Tennessee Valley Authority, 1101 Market Street, Chattanooga, Tennessee 37402

CNL-15-190

September 23, 2015

10 CFR 50.90

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

Watts Bar Nuclear Plant, Unit 2
Construction Permit No. CPPR-92
NRC Docket No. 50-391

Subject: **Watts Bar Nuclear Plant Unit 2 – Submittal of Final Revision 0 of the Technical Specifications & Technical Specification Bases, and Final Revision 0 of the Technical Requirements Manual & Technical Requirements Manual Bases**

References:

1. Letter from TVA to NRC, CNL-15-134, "Watts Bar Nuclear Plant Unit 2 – Submittal of Developmental and Final Revision J of the Technical Specification & Technical Specification Bases, and Developmental and Final Revision E of the Technical Requirements Manual & Technical Requirements Manual Bases," dated July 6, 2015 [ML15187A461]

2. Letter from TVA to NRC, CNL-15-177, "Watts Bar Nuclear Plant Unit 2 – Submittal of Replacement Pages for Developmental and Final Revision J of the Technical Specification & Technical Specification Bases, and Developmental and Final Revision E of the Technical Requirements Manual & Technical Requirements Manual Bases," dated September 4, 2015 [ML15247A564]

3. Email from R. Schaaf, NRC, to G. Arent, TVA, dated September 10, 2015

4. Email from J. Poole, NRC, to G. Arent, TVA, dated September 18, 2015

By letter dated July 6, 2015 (Reference 1), Tennessee Valley Authority (TVA) submitted Developmental Revision J of the Watts Bar Nuclear Plant (WBN) Unit 2 Technical Specifications (TS) and TS Bases as well as Revision E of the WBN Unit 2 Technical Requirements Manual (TRM) and TRM Bases. By letter dated September 4, 2015 (Reference 2), TVA submitted replacement pages for specific sections of Reference 1 to address NRC staff questions and comments. The Nuclear Regulatory Commission (NRC) staff provided requests for additional information (RAIs) regarding References 1 and 2 by emails dated September 10, 2015 (Reference 3) and September 18, 2015 (Reference 4).

The purpose of this letter is to provide responses to the Reference 3 and 4 RAIs. In this letter, TVA is also submitting the final Revision 0 version of the WBN Unit 2 TS along with the TS Bases, and final Revision 0 version of the TRM along with the TRM Bases. In addition, a final version of the Environmental Protection Plan (Non-Radiological) is provided.

Enclosure 1 provides a summary of responses, changes, and additional information to the NRC RAIs (References 3 and 4).

Enclosures 2 through 4 provide the final Revision 0 WBN Unit 2 TS, TS Bases, TRM and Bases, respectively. Enclosure 5 provides the final Environmental Protection Plan (Non-Radiological), which will become Appendix B of the WBN Unit 2 operating license.

It should be noted that the contents of Enclosures 3 and 4 (TS Bases, TRM and Bases), are not part of the TS, but are maintained separately by TVA in accordance with the applicable regulatory requirements (e.g., 10 CFR 50.59). These documents are provided to the NRC in support of issuance of the initial operating license for WBN Unit 2.

Enclosure 6 contains one new regulatory commitment as discussed in Enclosure 1. Please direct any questions concerning this matter to Gordon Arent at (423) 365-2004.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 23rd day of September 2015.

Respectfully,

J. W. Shea
Vice President, Nuclear Licensing

Enclosures:

1. Summary of Responses to NRC RAIs
2. WBN Unit 2 Technical Specifications
3. WBN Unit 2 Technical Specifications Bases
4. WBN Unit 2 Technical Requirements Manual and Bases
5. WBN Unit 2 Environmental Protection Plan (Non-Radiological)
6. List of Commitments

cc (Enclosures):

U.S. Nuclear Regulatory Commission, Region II
NRC Senior Resident Inspector - Watts Bar Nuclear Plant, Unit 2
NRC Project Manager - Watts Bar Nuclear Plant, Unit 2
Director - Division of Radiological Health – Tennessee State Department of Environment and Conservation

Enclosure 1

Summary of Responses to NRC RAIs

Item No.	NRC Question / Comment	WBN Response
1.	LCO 3.0.8 for snubbers added. - Need plant specific justification.	Limiting Condition for Operation (LCO) 3.0.8 has been deleted from Technical Specifications (TS) and the previous Technical Requirements Manual (TRM) Section 3.7.3, Snubbers, has been reinserted into the TRM. The Watts Bar Nuclear Plant Unit 2 (WBN2) TRM 3.7.3 is consistent with the Watts Bar Nuclear Plant Unit 1 (WBN1) TRM 3.7.3.
2.	LCO 3.2.1 Heat Flux Hot Channel Factor with relaxed axial offset control – changes to Condition B – No Required Action "B.2" text is present and justification needed for adding Required Actions B.2.1, B.2.2, B.2.3, and B.2.4. Justification additionally needed for SR 3.2.1.2 changes.	The Note in Condition B has been revised to reflect Required Actions B.2.1 through B.2.4 vice 'B.2'. The technical justification for the changes to TS 3.2.1 and associated Bases will be provided to the NRC in separate correspondence. See Commitment 1 in Enclosure 6.
3.	Table 3.3.1-1 Page 4, Item 14, Turbine Trip – SR 3.3.1.10 (b)(c) added. It is in WB1 TS Amendment No. 7, but was not in WB2 developmental Rev. G. Justification needed.	An administrative error occurred on a previous developmental revision to the TS in which SR 3.3.1.10 and its applicable footnotes were inadvertently removed. The SR was reinserted to correct this error. This action was discussed in a previous Request for Additional Information (RAI) response to the NRC in letter CNL-14-150, dated 10/21/2014.
4.	LCO 3.5.2 ECCS – Operating – removal of Note 2. Explanation in enclosure 2 of submittal is "Delete note 2 regarding COMS & MODE 3 would not apply to WBN2 due to significantly different COMS temp (350 vs 217)." – I may be able to verify this if I have access to data on COMS to verify that it is not needed until 217 degrees on Unit 2. Since 217 is less than MODE 3 temp then the note would not be required because it would lie outside the mode of applicability of the spec (MODES 1,2 and 3). - Need plant specific justification.	Note 2 was reinserted in the TS along with the applicable Bases text consistent with the previous revision. This maintains consistency with WBN1. An editorial change is made to refer to the COMS temperature specified in the PTLR, consistent with other requirements in the WBN2 TS.
5.	LCO 3.6.11 - SR 3.6.11.2 – Ice Weight. - Need plant specific justification.	The ice weight values in SR 3.6.11.2 and 3.6.11.3 were revised to reflect the revised containment analysis for WBN2. Reference letter

Enclosure 1

Summary of Responses to NRC RAIs

Item No.	NRC Question / Comment	WBN Response
		CNL-15-127, dated 8/13/2015, which provided the revised analysis as well as markups of the TS and TS Bases.
6.	LCO 3.6.12 Ice Condenser Doors. Where is the justification for addition of Actions Note 2.	The Note has been deleted from the TS and the appropriate text added to the TS Bases, consistent with a previous revision of the TS. Adding the text back into the TS Bases maintains consistency with WBN1 which has the same Bases wording. The acceptability of the Bases wording was previously addressed in the NRC Safety Evaluation for WBN1 License Amendment No. 25, dated 7/17/2000.
7.	SR 3.8.1.8 changes – justification?	The changes to SR 3.8.1.8 are the result of a revision to the WBN1 TS related to the Common Station Service Transformers. This ensures consistency between WBN1 and WBN2 for the electrical systems. Reference license amendment request dated 08/01/2013, as supplemented by letter CNL-14-107 dated 1/29/2015, and letter CNL-15-078 dated 6/12/2015.
8.	Addition of SR 3.8.1.22 – justification?	The changes to SR 3.8.1.8 are the result of a revision to the WBN1 TS related to the Common Station Service Transformers. This ensures consistency between WBN1 and WBN2 for the electrical systems. Reference license amendment request dated 08/01/2013, as supplemented by letter CNL-14-107 dated 1/29/2015, and letter CNL-15-078 dated 6/12/2015.
9.	Why don't LCO 3.8.4 NOTES for Unit 2 match Unit 1?	The Note regarding use of the C-S Diesel Generator (DG) as a substitute is not applicable for WBN2 as this DG is not configured to support plant operation.
10	B 3.8.4 – 125 V DG DC electrical power subsystem change from 30 minutes to 4 hours justification? Is this just unit specific difference (i.e. bought longer duty batteries?)	The time change from 30 minutes to 4 hours was discussed in the RAI Response for developmental revision I in letter CNL-15-094, dated 8/26/2015. The change is consistent with the WBN2 design basis. A markup of the revised text showing the change to 4 hours was included in the RAI response.
11.	TS 5.7.2.12 b.2 (Rev. G Sheet modified to Rev. J – meanwhile Rev. I was acceptable). – Why omit the words "For design basis	Developmental revision G was submitted via letter dated 2/28/2012. Enclosure 1 to the letter provided a discussion of changes and

Enclosure 1

Summary of Responses to NRC RAIs

Item No.	NRC Question / Comment	WBN Response
	accidents that have a faulted steam generator, accident induced …" and "…for the faulted steam generator and 150 gallons per day (gpd) for the non-faulted steam generators. For design basis accidents that do not have a faulted steam generator, accident induced leakage is not to exceed 150 gpd per steam generator." Is this an inadvertent omission or an unjustified technical change?	stated that TS 5.7.2.12 and TS 3.4.17 (and Bases) were revised to incorporate appropriate information from TSTF-510, revision 2, consistent with the NRC email request dated 1/24/2012. TVAs response to NRC questions was provided in Enclosure 2 of the letter. As a result, specific text was removed from TS 5.7.2.12 and placed in TS Bases 3.4.17 while other words were added to TS 5.7.2.12. The revised TS and Bases pages were provided in Enclosure 3. In a subsequent response to NRC RAI questions, minor wording changes were made as documented in letter CNL-14-143, dated 9/3/2014.
12.	TS 5.7.2.12 b.2 per Watts Bar Unit 2 TS Revision I everything in the last sentence following "… SG" was removed. Now in Rev. J the additional language "… except for specific types of degradation at specific locations as described in paragraph c. of the Steam Generator Program." has been restored. What is the justification?	The additional language "… except for specific types of degradation at specific locations as described in paragraph c. of the Steam Generator Program" has been deleted in the TS. The additional wording is not necessary. The sentence now reads "Leakage is not to exceed 1 gpm per SG." This ends the paragraph.
13.	TS 5.7.2.18 (p 5.0-24) – Changes to the Safety Function Determination Program originally submitted pre GDC 5 resolutions on 6/17/15 remain (TSTF-273 submittal). No supplemental change sheets were submitted with supplement dated 9/4/15.	Letter CNL-15-147, dated 7/14/2015 for WBN1 withdrew the proposed changes to TS 5.7.2.18. This was stated in the cover letter. A revised markup was not provided in the submittal. The proposed words have been deleted in the TS. This will maintain consistency between the WBN1 and WBN2 TS.
14.	SR 3.7.7.4 (p 3.7-17) and 3.7.7.5 (p 3.7-18) differ from unit 1. Additionally the unit number of the pumps has been changed from previous revision. Please confirm that unit No. is, in fact, what changed (admin only) and that unit 2 is correct here (seems obvious – but why was it incorrect previously). Additionally, the pump number does not agree with the basis for SR 3.7.7.4 in that the basis (p B3.7-40) still mentions pump 1 B-B (not 2 B-B like the	The changes proposed in revision J to SR 3.7.7.4 and SR 3.7.7.5 contained some administrative errors in pump and train numbers (WBN1 vice WBN2). The text was corrected to provide the correct pump and train numbers. The format of the Notes for the respective SRs is maintained. Additional text was added to the TS Bases to describe the addition of the Notes. The changes support the operability of the Component Cooling System (CCS) under

Item No.	NRC Question / Comment	WBN Response
	SR). Will this be a change to Unit 1 TS also?	configurations that can occur during dual unit operation, since CCS is a shared system for WBN1 and WBN2. A similar change will be considered in the future for the WBN1 TS, but is not currently required to support WBN1 operation.
15.	SR 3.8.1.19 c. why remove the words "DGs of the same power train …" and replace with "DG"?	This is an editorial change to provide consistency in the terminology for the DGs. Each DG is a stand-alone DG with individual operability requirements.
16.	TS 5.7.2.14 – Something seems inconsistent with application of the VFTP to Reactor Building Purge (RBP). Was RBP removed from the VFTP? Why is table 6.5-3 mentioned in paragraphs 5.7.2.14 a and b but deleted from c and d? No laboratory test or pressure drop test required for this? Then overall, although consistent with previous revisions of TS for unit 2, why was RBP removed from the tables in the Spec (Unit 1 has it)? This is not mentioned as a unit difference in Table 1 of the submittal.	The Reactor Building Purge (RBP) System was removed from the Ventilation Filter Testing Program (VFTP) as a result of the implementation of the alternate source term methodology for the fuel handling analysis (FHA). The discussion of this change and revised TS were provided in a letter dated 12/12/2013 regarding the fuel handling accident dose analysis. In addition, FSAR Amendment 111 deleted FSAR Table 6.5-3, thus this table reference has now been deleted from all the applicable paragraphs in TS 5.7.2.14. Consistent with the removal of the RBP System from the program, no laboratory tests or pressure drop tests are required.
17.	TS 5.7.2.19 Containment Leak Rate Testing Program peak pressure paragraph is revised. Is this to account for new analysis?	Letter CNL-14-178, dated 10/31/2014, provided an update to TS 5.7.2.19 to clarify that for containment leakage rate testing purposes, the maximum allowable internal containment pressure of 15.0 psig is utilized for P_a. As stated in the letter, this change is considered administrative, and aligns the TS with TS Bases 3.6.1 (Applicable Safety Analyses, second paragraph) and FSAR Section 6.2.6, Containment Leakage Testing.
18.	5.9.6 - please explain unit differences.	The change to the format for TS 5.9.6 is an administrative change to improve consistency with the Standard Technical Specifications 5.6.4, and does not change any technical information. As shown in the STS, the information regarding Pressurizer Power Operated Relief Valve (PORV) lift settings and arming temperature, and the

Item No.	NRC Question / Comment	WBN Response
		related TS LCOs are provided in the first subsection (a). The WBN1 TS have not been reformatted.
19.	5.9.7 - Why remove the word emergency?	Standard terminology for the WBN diesel generators is 'diesel generators' or 'DGs'. This is an editorial change only. Note: A search of the TS and TS Bases identified one additional correction to the TS and five corrections in the TS Bases to ensure consistent terminology in revision 0. These editorial changes were made in the following sections: - TS 3.7.8 Required Action A.1 Note 1. - TS Bases 3.7.8, Actions A.1, first paragraph. - TS Bases 3.5.1, Applicable Safety Analysis, second paragraph. - TS Bases 3.5.2, Background, next to last paragraph. - TS Bases 3.5.2, Applicable Safety Analysis, subparagraph a. - TS Bases 3.5.2, Actions A.1, next to last paragraph.
20.	In addition to the above questions and comments, there were numerous items that related to minor editorial or typographical issues that were discussed during two teleconferences with the NRC staff on 9/11/2015 and 9/18/2015. The specific items are not repeated in this response table due to the minor or editorial nature of the items.	These items were discussed with the NRC as appropriate. In some cases, minor editorial or typographical errors were corrected in revision 0 of the TS, TS Bases, TRM, and TRM Bases. In some cases, reference to previous documents were provided that identified the item resolution.

ENCLOSURE 2

WBN Unit 2 Technical Specifications

Tennessee Valley Authority

Watts Bar Nuclear Plant Unit 2

Technical Specifications

LIST OF TABLES

LIST OF FIGURES

ACRONYM	TITLE
ABGTS	Auxiliary Building Gas Treatment System
ACRP	Auxiliary Control Room Panel
AFD	Axial Flux Difference
AFW	Auxiliary Feedwater System
ARFS	Air Return Fan System
ARO	All Rods Out
ARV	Atmospheric Relief Valve
ASME	American Society of Mechanical Engineers
BOC	Beginning of Cycle
CAOC	Constant Axial Offset Control
CCS	Component Cooling Water System
CFR	Code of Federal Regulations
COLR	Core Operating Limits Report
CREVS	Control Room Emergency Ventilation System
CSS	Containment Spray System
CST	Condensate Storage Tank
DNB	Departure from Nucleate Boiling
ECCS	Emergency Core Cooling System
EFPD	Effective Full-Power Days
EGTS	Emergency Gas Treatment System
EOC	End of Cycle
ERCW	Essential Raw Cooling Water
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Features Actuation System
HEPA	High Efficiency Particulate Air
HVAC	Heating, Ventilating, and Air-Conditioning

ACRONYM	TITLE
LCO	Limiting Condition For Operation
MFIV	Main Feedwater Isolation Valve
MFRV	Main Feedwater Regulation Valve
MSIV	Main Steam Line Isolation Valve
MSSV	Main Steam Safety Valve
MTC	Moderator Temperature Coefficient
NMS	Neutron Monitoring System
ODCM	Offsite Dose Calculation Manual
PCP	Process Control Program
PDMS	Power Distribution Monitoring System
PIV	Pressure Isolation Valve
PORV	Power-Operated Relief Valve
PTLR	Pressure and Temperature Limits Report
QPTR	Quadrant Power Tilt Ratio
RAOC	Relaxed Axial Offset Control
RCCA	Rod Cluster Control Assembly
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RTP	Rated Thermal Power
RTS	Reactor Trip System
RWST	Refueling Water Storage Tank
SG	Steam Generator
SI	Safety Injection
SL	Safety Limit
SR	Surveillance Requirement
UHS	Ultimate Heat Sink

LIST OF EFFECTIVE PAGES (continued)

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
i	0	2.0-1	0
ii	0	2.0-2	0
iii	0	3.0-1	0
iv	0	3.0-2	0
v	0	3.0-3	0
vi	0	3.0-4	0
vii	0	3.0-5	0
viii	0	3.1-1	0
ix	0	3.1-2	0
x	0	3.1-3	0
xi	0	3.1-4	0
xii	0	3.1-5	0
xiii	0	3.1-6	0
xiv	0	3.1-7	0
1.1-1	0	3.1-8	0
1.1-2	0	3.1-9	0
1.1-3	0	3.1-10	0
1.1-4	0	3.1-11	0
1.1-5	0	3.1-12	0
1.1-6	0	3.1-13	0
1.1-7	0	3.1-14	0
1.1-8	0	3.1-15	0
1.2-1	0	3.1-16	0
1.2-2	0	3.1-17	0
1.2-3	0	3.1-18	0
1.3-1	0	3.1-19	0
1.3-2	0	3.1-20	0
1.3-3	0	3.1-21	0
1.3-4	0	3.2-1	0
1.3-5	0	3.2-2	0
1.3-6	0	3.2-3	0
1.3-7	0	3.2-4	0
1.3-8	0	3.2-5	0
1.3.9	0	3.2-6	0
1.3-10	0	3.2-7	0
1.3-11	0	3.2-8	0
1.3-12	0	3.2-9	0
1.4-1	0	3.2-10	0
1.4-2	0	3.2-11	0
1.4-3	0	3.3-1	0
1.4-4	0	3.3-2	0

(continued)

LIST OF EFFECTIVE PAGES (continued)

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
3.3-3	0		
3.3-4	0	3.3-47	0
3.3-5	0	3.3-48	0
3.3-6	0	3.3-49	0
3.3-7	0	3.3-50	0
3.3-8	0	3.3-51	0
3.3-9	0	3.3-52	0
3.3-10	0	3.3-53	0
3.3-11	0	3.3-54	0
3.3-12	0	3.3-55	0
3.3-13	0	3.3-56	0
3.3-14	0	3.3-57	0
3.3-15	0	3.3-58	0
3.3-16	0	3.3-59	0
3.3-17	0	3.3-60	0
3.3-18	0	3.3-61	0
3.3-19	0	3.3-62	0
3.3-20	0	3.3-63	0
3.3-21	0	3.3-64	0
3.3-22	0	3.3-65	0
3.3-23	0	3.4-1	0
3.3-24	0	3.4-2	0
3.3-25	0	3.4-3	0
3.3-26	0	3.4-4	0
3.3-27	0	3.4-5	0
3.3-28	0	3.4-6	0
3.3-29	0	3.4-7	0
3.3-30	0	3.4-8	0
3.3-31	0	3.4-9	0
3.3-32	0	3.4-10	0
3.3-33	0	3.4-11	0
3.3-34	0	3.4-12	0
3.3-35	0	3.4-13	0
3.3-36	0	3.4-14	0
3.3-37	0	3.4-15	0
3.3-38	0	3.4-16	0
3.3-39	0	3.4-17	0
3.3-40	0	3.4-18	0
3.3-41	0	3.4-19	0
3.3-42	0	3.4-20	0
3.3-43	0	3.4-21	0
3.3-44	0	3.4-22	0
3.3-45	0	3.4-23	0
3.3-46	0	3.4-24	0

(continued)

LIST OF EFFECTIVE PAGES (continued)

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
3.4-25	0	3.6-18	0
3.4-26	0	3.6-19	0
3.4-27	0	3.6-20	0
3.4-28	0	3.6-21	0
3.4-29	0	3.6-22	0
3.4-30	0	3.6-23	0
3.4-31	0	3.6-24	0
3.4-32	0	3.6-25	0
3.4-33	0	3.6-26	0
3.4-34	0	3.6-27	0
3.4-35	0	3.6-28	0
3.4-36	0	3.6-29	0
3.4-37	0	3.6-30	0
3.4-38	0	3.6-31	0
3.4-39	0	3.6-32	0
3.5-1	0	3.6-33	0
3.5-2	0	3.6-34	0
3.5-3	0	3.6-35	0
3.5-4	0	3.6-36	0
3.5-5	0	3.7-1	0
3.5-6	0	3.7-2	0
3.5-7	0	3.7-3	0
3.5-8	0	3.7-4	0
3.5-9	0	3.7-5	0
3.5-10	0	3.7-6	0
3.5-11	0	3.7-7	0
3.6-1	0	3.7-8	0
3.6-2	0	3.7-9	0
3.6-3	0	3.7-10	0
3.6-4	0	3.7-11	0
3.6-5	0	3.7-12	0
3.6-6	0	3.7-13	0
3.6-7	0	3.7-14	0
3.6-8	0	3.7-15	0
3.6-9	0	3.7-16	0
3.6-10	0	3.7-17	0
3.6-11	0	3.7-18	0
3.6-12	0	3.7-19	0
3.6-13	0	3.7-20	0
3.6-14	0	3.7-21	0
3.6-15	0	3.7-22	0
3.6-16	0	3.7-23	0
3.6-17	0	3.7-24	0

(continued)

LIST OF EFFECTIVE PAGES (continued)

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
3.7-25	0	3.8-32	0
3.7-26	0	3.8-33	0
3.7-27	0	3.8-34	0
3.7-28	0	3.8-35	0
3.7-29	0	3.8-36	0
3.7-30	0	3.8-37	0
3.7-31	0	3.8-38	0
3.7-32	0	3.8-39	0
3.7-33	0	3.8-40	0
3.7-34	0	3.9-1	0
3.7-35	0	3.9-2	0
3.7-36	0	3.9-3	0
3.8-1	0	3.9-4	0
3.8-2	0	3.9-5	0
3.8-3	0	3.9-6	0
3.8-4	0	3.9-7	0
3.8-5	0	3.9-8	0
3.8-6	0	3.9-9	0
3.8-7	0	3.9-10	0
3.8-8	0	3.9-11	0
3.8-9	0	3.9-12	0
3.8-10	0	3.9-13	0
3.8-11	0	4.0-1	0
3.8-12	0	4.1-2	0
3.8-13	0	4.0-3	0
3.8-14	0	4.0-4	0
3.8-15	0	4.0-5	0
3.8-16	0	4.0-6	0
3.8-17	0	4.0-7	0
3.8-18	0	4.0-8	0
3.8-19	0	4.0-9	0
3.8-20	0	5.0-1	0
3.8-21	0	5.0-2	0
3.8-22	0	5.0-3	0
3.8-23	0	5.0-4	0
3.8-24	0	5.0-5	0
3.8-25	0	5.0-6	0
3.8-26	0	5.0-7	0
3.8-27	0	5.0-8	0
3.8-28	0	5.0-9	0
3.8-29	0	5.0-10	0
3.8-30	0	5.0-11	0
3.8-31	0	5.0-12	0

(continued)

LIST OF EFFECTIVE PAGES (continued)

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
5.0-13	0		
5.0-14	0		
5.0-15	0		
5.0-16	0		
5.0-17	0		
5.0-18	0		
5.0-19	0		
5.0-20	0		
5.0-21	0		
5.0-22	0		
5.0-23	0		
5.0-24	0		
5.0-25	0		
5.0-26	0		
5.0-27	0		
5.0-28	0		
5.0-29	0		
5.0-30	0		
5.0-31	0		
5.0-32	0		
5.0-33	0		
5.0-34	0		
5.0-35	0		
5.0-36	0		
5.0-37	0		
5.0-38	0		
5.0-39	0		
5.0-40	0		

(continued)

1.0 USE AND APPLICATION

1.1 Definitions

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

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
ACTUATION LOGIC TEST	An ACTUATION LOGIC TEST shall be the application of various simulated or actual input combinations in conjunction with each possible interlock logic state and the verification of the required logic output. The ACTUATION LOGIC TEST, as a minimum, shall include a continuity check of output devices.
AXIAL FLUX DIFFERENCE (AFD)	AFD shall be the difference in normalized flux signals between the top and bottom halves of a two section excore neutron detector.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel so that it responds within the required range and accuracy to known input. The CHANNEL CALIBRATION shall encompass the entire channel, including the required sensor, alarm, interlock, display, and trip functions. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION shall include an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping calibrations or total channel steps so that the entire channel is calibrated.

(continued)

1.1 Definitions (continued)

CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.
CHANNEL OPERATIONAL TEST (COT)	A COT shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify the OPERABILITY of required alarm, interlock, display, and trip functions. The COT shall include adjustments, as necessary, of the required alarm, interlock, and trip setpoints so that the setpoints are within the required range and accuracy.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or other reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is the unit specific document that provides cycle specific parameter limits for the initial and current reload cycle. These cycle specific parameter limits shall be determined for the initial and each reload cycle in accordance with Specification 5.9.5. Plant operation within these limits is addressed in individual Specifications.
DOSE EQUIVALENT I-131	DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) that alone would produce the same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table E-7 of Regulatory Guide 1.109, Rev. 1, NRC, 1977.

(continued)

1.1 Definitions (continued)

$\bar{E}$ - AVERAGE DISINTEGRATION ENERGY	$\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes, other than iodines, with half lives > 15 minutes, making up at least 95% of the total noniodine activity in the coolant.
ENGINEERED SAFETY FEATURE (ESF) RESPONSE TIME	The ESF RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF 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. In lieu of measurement, response time may be verified for selected components provided that the components and the methodology for verification have been previously reviewed and approved by the NRC.
L_a	The maximum allowable primary containment leakage rate, L_a, shall be .25% of primary containment air weight per day at the calculated peak containment pressure (P_a).

(continued)

1.1 Definitions (continued)

LEAKAGE	LEAKAGE shall be: a. <u>Identified LEAKAGE</u> 1. LEAKAGE, such as that from pump seals or valve packing (except reactor coolant pump (RCP) seal water injection or leakoff), that is captured and conducted to collection systems or a sump or collecting tank; 2. LEAKAGE into the containment 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; or 3. Reactor Coolant System (RCS) LEAKAGE through a steam generator to the Secondary System (primary-to-secondary LEAKAGE); b. <u>Unidentified LEAKAGE</u> All LEAKAGE (except RCP seal water injection or leakoff) that is not identified LEAKAGE; c. <u>Pressure Boundary LEAKAGE</u> LEAKAGE (except primary-to-secondary LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.
MASTER RELAY TEST	A MASTER RELAY TEST shall consist of energizing each master relay and verifying the OPERABILITY of each relay. The MASTER RELAY TEST shall include a continuity check of each associated slave relay.
MODE	A MODE shall correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.

(continued)

1.1 Definitions (continued)

OPERABLE-OPERABILITY	A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PDMS	The Power Distribution Monitoring System (PDMS) is a real-time three dimensional core monitoring system. The system utilizes existing core instrumentation data and an on-line neutronics code to provide surveillance of core thermal limits.
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; 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 RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as 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 5.9.6. Plant operation within these operating limits is addressed in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," and LCO 3.4.12, "Cold Overpressure Mitigation System (COMS)."

(continued)

1.1 Definitions (continued)

QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3411 MWt.
REACTOR TRIP SYSTEM (RTS) RESPONSE TIME	The RTS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RTS trip setpoint at the channel sensor until loss of stationary gripper coil voltage. 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. In lieu of measurement, response time may be verified for selected components provided that the components and the methodology for verification have been previously reviewed and approved by the NRC.
SHUTDOWN MARGIN (SDM)	SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming: a. All rod cluster control assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. With any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM; and b. In MODES 1 and 2, the fuel and moderator temperatures are changed to the nominal zero power design level.
SLAVE RELAY TEST	A SLAVE RELAY TEST shall consist of energizing each slave relay and verifying the OPERABILITY of each slave relay. The SLAVE RELAY TEST shall include, as a minimum, a continuity check of associated testable actuation devices.

(continued)

1.1 Definitions (continued)

STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.
TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT)	A TADOT shall consist of operating the trip actuating device and verifying the OPERABILITY of required alarm, interlock, display, and trip functions. The TADOT shall include adjustment, as necessary, of the trip actuating device so that it actuates at the required setpoint within the required accuracy.

Table 1.1-1 (page 1 of 1)
MODES

MODE	TITLE	REACTIVITY CONDITION (k_{eff})	% RATED THERMAL POWER [a]	AVERAGE REACTOR COOLANT TEMPERATURE (°F)
1	Power Operation	≥ 0.99	> 5	NA
2	Startup	≥ 0.99	≤ 5	NA
3	Hot Standby	< 0.99	NA	≥ 350
4	Hot Shutdown [b]	< 0.99	NA	350 > T_{avg} > 200
5	Cold Shutdown [b]	< 0.99	NA	≤ 200
6	Refueling [c]	NA	NA	NA

(a) Excluding decay heat.

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

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

1.0 USE AND APPLICATION

1.2 Logical Connectors

PURPOSE	The purpose of this section is to explain the meaning of logical connectors. Logical connectors are used in Technical Specifications (TS) to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, Surveillances, and Frequencies. The only logical connectors that appear in TS are AND and OR. The physical arrangement of these connectors constitutes logical conventions with specific meanings.
BACKGROUND	Several levels of logic may be used to state Required Actions. These levels are identified by the placement (or nesting) of the logical connectors and by the number assigned to each Required Action. The first level of logic is identified by the first digit of the number assigned to a Required Action and the placement of the logical connector in the first level of nesting (i.e., left justified with the number of the Required Action). The successive levels of logic are identified by additional digits of the Required Action number and by successive indentations of the logical connectors. When logical connectors are used to state a Condition, Completion Time, Surveillance, or Frequency, only the first level of logic is used, and the logical connector is left justified with the statement of the Condition, Completion Time, Surveillance, or Frequency.

1.2 Logical Connectors (continued)

EXAMPLES

The following examples illustrate the use of logical connectors.

EXAMPLE 1.2-1

ACTIONS

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

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

(continued)

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-2

ACTIONS

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

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

1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE	The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.
BACKGROUND	Limiting Conditions for Operation (LCOs) specify minimum requirements for ensuring safe operation of the unit. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).
DESCRIPTION	The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the unit is in a MODE or specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the unit is not within the LCO Applicability. If situations are discovered that require entry into more than one Condition at a time within a single LCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition. Once a Condition has been entered, subsequent trains, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will <u>not</u> result in separate entry into the Condition, unless specifically stated. The Required Actions of the Condition continue to apply to each additional failure, with Completion Times based on initial entry into the Condition.

(continued)

1.3 Completion Times

DESCRIPTION (continued)

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

a. Must exist concurrent with the first inoperability; and

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

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

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

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

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

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

(continued)

1.3 Completion Times (continued)

EXAMPLES

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

EXAMPLE 1.3-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

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

The Required Actions of Condition B are to be in MODE 3 within 6 hours AND in MODE 5 within 36 hours. A total of 6 hours is allowed for reaching MODE 3 and a total of 36 hours (not 42 hours) is allowed for reaching MODE 5 from the time that Condition B was entered. If MODE 3 is reached within 3 hours, the time allowed for reaching MODE 5 is the next 33 hours because the total time allowed for reaching MODE 5 is 36 hours.

If Condition B is entered while in MODE 3, the time allowed for reaching MODE 5 is the next 36 hours.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pump inoperable.	A.1 Restore pump to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

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

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

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

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

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-2 (continued)

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

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-3

ACTIONS

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

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-3 (continued)

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

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

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

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

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

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

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

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-5

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

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

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

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.

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-5 (continued)

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

EXAMPLE 1.3-6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One channel inoperable.	A.1 Perform SR 3.x.x.x. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

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

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

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable	A.1 Verify affected subsystem isolated.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore subsystem to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

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

If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour or any subsequent 8 hour interval from the previous performance (plus the extension allowed by SR 3.0.2), Condition B is entered. The Completion Time clock for Condition A does not stop after Condition B is entered, but continues from the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

1.3 Completion Times

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

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE	The purpose of this section is to define the proper use and application of Frequency requirements.
DESCRIPTION	Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated LCO. An understanding of the correct application of the specified Frequency is necessary for compliance with the SR. The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR as well as certain Notes in the Surveillance column that modify performance requirements. Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

1.4 Frequency (continued)

EXAMPLES

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

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the interval specified in the Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Example 1.4-3), then SR 3.0.3 becomes applicable.

If the interval as specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, the Surveillance must be performed within the Frequency requirements of SR 3.0.2 prior to entry into the MODE or other specified condition. Failure to do so would result in a violation of SR 3.0.4.

(continued)

EXAMPLES (continued)

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

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

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

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the extension allowed by SR 3.0.2. "Thereafter" indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

(continued)

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-3

SURVEILLANCE REQUIREMENTS

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

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

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

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

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

In MODES 1 and 2, the combination of THERMAL POWER, Reactor Coolant System (RCS) highest loop average temperature, and pressurizer pressure shall not exceed the SLs specified in Figure 2.1.1-1.

2.1.2 RCS Pressure SL

In MODES 1, 2, 3, 4, and 5, the RCS pressure shall be maintained ≤ 2735 psig.

2.2 SL Violations

2.2.1 If SL 2.1.1 is violated, restore compliance and be in MODE 3 within 1 hour.

2.2.2 If SL 2.1.2 is violated:

2.2.2.1 In MODE 1 or 2, restore compliance and be in MODE 3 within 1 hour.

2.2.2.2 In MODE 3, 4, or 5, restore compliance within 5 minutes.

2.2.3 Within 1 hour, notify the NRC Operations Center, in accordance with 10 CFR 50.72.

2.2.4 Within 24 hours, notify the Plant Manager and Site Vice President.

2.2.5 Within 30 days a Licensee Event Report (LER) shall be prepared pursuant to 10 CFR 50.73. The LER shall be submitted to the NRC, the NSRB, the Plant Manager, and Site Vice President.

2.2.6 Operation of the unit shall not be resumed until authorized by the NRC.

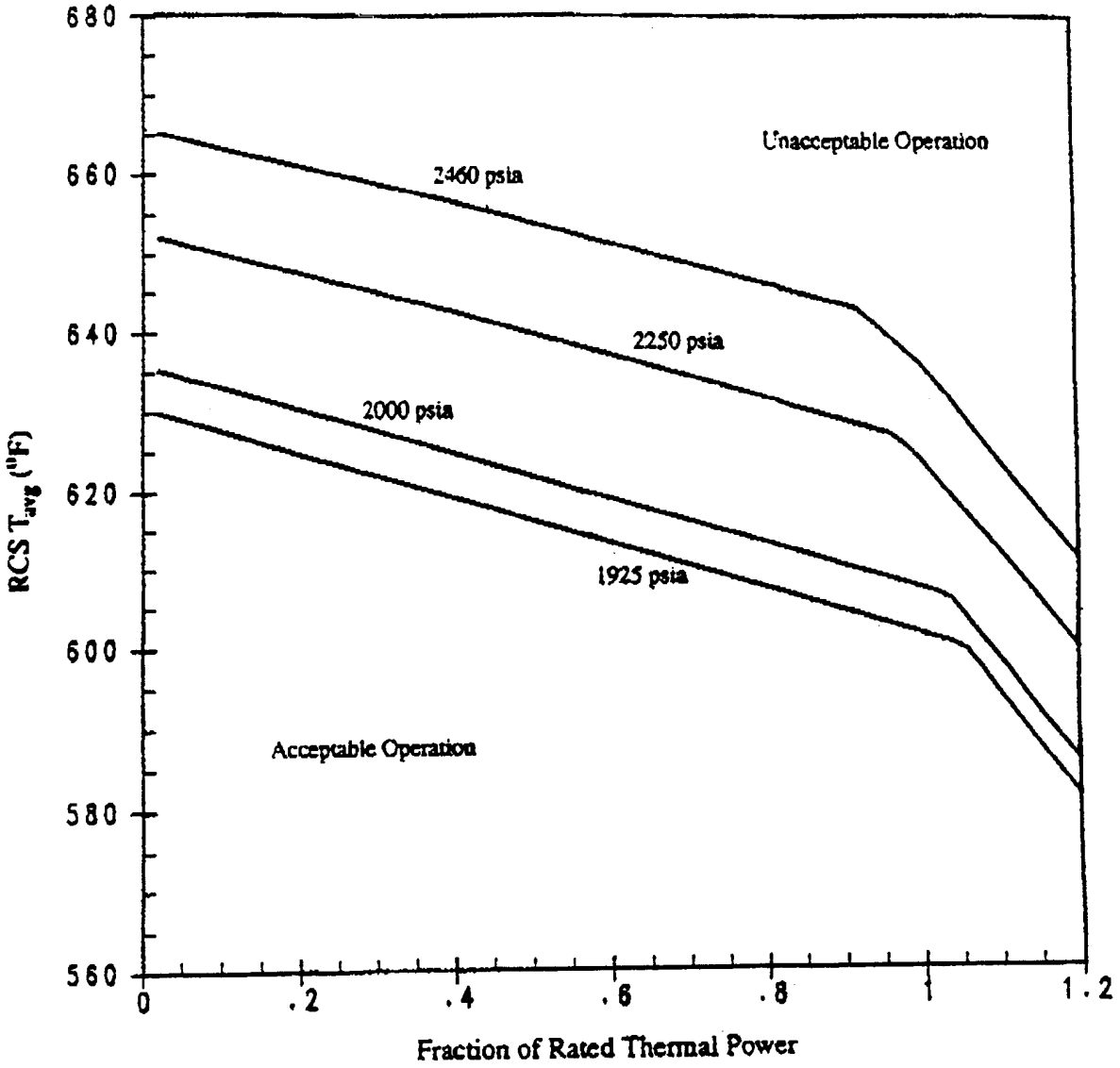


Figure 2.1.1-1 (page 1 of 1)
Reactor Core Safety Limits

3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1 LCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in LCO 3.0.2, 3.0.7 and 3.0.8.

LCO 3.0.2 Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met, except as provided in LCO 3.0.5 and LCO 3.0.6.

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

LCO 3.0.3 When an LCO is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS the unit shall be placed in a MODE or other specified condition in which the LCO is not applicable. Action shall be initiated within 1 hour to place the unit, as applicable, in:

a. MODE 3 within 7 hours;

b. MODE 4 within 13 hours; and

c. MODE 5 within 37 hours.

Exceptions to this Specification are stated in the individual Specifications.

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

LCO 3.0.3 is only applicable in MODES 1, 2, 3, and 4.

LCO 3.0.4 When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall only be made:

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

(continued)

3.0 LCO APPLICABILITY

LCO 3.0.4 (continued)

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

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

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

LCO 3.0.5

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

LCO 3.0.6

When a supported system LCO is not met solely due to a support system LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system LCO ACTIONS are required to be entered. This is an exception to LCO 3.0.2 for the supported system. In this event, additional evaluations and limitations may be required in accordance with Specification 5.7.2.18, "Safety Function Determination Program (SFDP)." If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

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

3.0 LCO APPLICABILITY (continued)

LCO 3.0.7	Test Exception LCO 3.1.9 allows specified Technical Specification (TS) requirements to be changed to permit performance of special tests and operations. Unless otherwise specified, all other TS requirements remain unchanged. Compliance with Test Exception LCOs is optional. When a Test Exception LCO is desired to be met but is not met, the ACTIONS of the Test Exception LCO shall be met. When a Test Exception LCO is not desired to be met, entry into a MODE or other specified condition in the Applicability shall be made in accordance with the other applicable Specifications.

3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

SR 3.0.1

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

SR 3.0.2

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

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

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

Exceptions to this Specification are stated in the individual Specifications.

SR 3.0.3

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

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

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

3.0 SR APPLICABILITY (continued)

SR 3.0.4

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

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

3.1 REACTIVITY CONTROL SYSTEMS

3.1.1 SHUTDOWN MARGIN (SDM) - T_{avg} > 200°F

LCO 3.1.1 SDM shall be ≥ 1.6% Δk/k.

APPLICABILITY: MODE 2 with k_{eff} < 1.0,
MODES 3 and 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.1.1	Verify SDM is ≥ 1.6% Δk/k.	24 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.2 SHUTDOWN MARGIN (SDM) - T_{avg} ≤ 200°F

LCO 3.1.2 The SDM shall be ≥ 1.0% Δk/k.

APPLICABILITY: MODE 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.2.1	Verify SDM is ≥ 1.0% Δk/k.	24 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.3 Core Reactivity

LCO 3.1.3 The measured core reactivity shall be within ± 1% $\Delta k/k$ of predicted values.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Measured core reactivity not within limit.	A.1	Re-evaluate core design and safety analysis, and determine that the reactor core is acceptable for continued operation.	72 hours
	AND		
	A.2	Establish appropriate operating restrictions and SRs.	72 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	----------NOTE---------- The predicted reactivity values may be adjusted (normalized) to correspond to the measured core reactivity prior to exceeding a fuel burnup of 60 effective full power days (EFPD) after each fuel loading. ---------- Verify measured core reactivity is within ± 1% $\Delta k/k$ of predicted values.	Once prior to entering MODE 1 after initial fuel loading and each refueling <u>AND</u> ----------NOTE--------- Only required after 60 EFPD ---------- 31 EFPD thereafter

3.1 REACTIVITY CONTROL SYSTEMS

3.1.4 Moderator Temperature Coefficient (MTC)

LCO 3.1.4 The MTC shall be maintained within the limits specified in the COLR. The maximum upper limit shall be $\leq 0\ \Delta k/k°F$ at hot zero power.

APPLICABILITY: MODE 1 and MODE 2 with $k_{eff} \geq 1.0$ for the upper MTC limit, MODES 1, 2, and 3 for the lower MTC limit.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. MTC not within upper limit.	A.1	Establish administrative withdrawal limits for control banks to maintain MTC within limit.	24 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 2 with $k_{eff} < 1.0$.	6 hours
C. MTC not within lower limit.	C.1	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify MTC is within upper limit	Once prior to entering MODE 1 after initial fuel loading and each refueling
SR 3.1.4.2	Verify MTC is within 300 ppm Surveillance limit specified in the COLR.	----------NOTE--------- Not required to be performed until 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm ---------- Once each cycle
SR 3.1.4.3	----------NOTES---------- 1. If the MTC is more negative than the 300 ppm Surveillance limit (not LCO limit) specified in the COLR, SR 3.1.4.3 shall be repeated once per 14 EFPD during the remainder of the fuel cycle. 2. SR 3.1.4.3 need not be repeated if the MTC measured at the equivalent of equilibrium RTP-ARO boron concentration of ≤ 60 ppm is less negative than the 60 ppm Surveillance limit specified in the COLR. ---------- Verify MTC is within lower limit.	----------NOTE--------- Not required to be performed until 7 EFPD after reaching the equivalent of an equilibrium RTP-ARO boron concentration of 300 ppm ---------- Once each cycle

3.1 REACTIVITY CONTROL SYSTEMS

3.1.5 Rod Group Alignment Limits

LCO 3.1.5 All shutdown and control rods shall be OPERABLE, with all individual indicated rod positions within 12 steps of their group step counter demand position.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more rod(s) untrippable.	A.1.1	Verify SDM is ≥ 1.6% Δk/k.	1 hour
	OR		
	A.1.2	Initiate boration to restore SDM to within limit.	1 hour
	AND		
	A.2	Be in MODE 3.	6 hours
B. One rod not within alignment limits.	B.1	Restore rod to within alignment limits.	1 hour
	OR		
	B.2.1.1	Verify SDM is ≥ 1.6% Δk/k.	1 hour
		OR	
	B.2.1.2	Initiate boration to restore SDM to within limit.	1 hour
	AND		(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2.2	Reduce THERMAL POWER to ≤ 75% RTP.	2 hours
	AND		
	B.2.3	Verify SDM is ≥ 1.6% Δk/k.	Once per 12 hours
	AND		
	B.2.4	Perform SR 3.2.1.1.	72 hours
	AND		
	B.2.5	Perform SR 3.2.2.1.	72 hours
	AND		
	B.2.6	Re-evaluate safety analyses and confirm results remain valid for duration of operation under these conditions.	5 days
C. Required Action and associated Completion Time of Condition B not met.	C.1	Be in MODE 3.	6 hours
D. More than one rod not within alignment limit.	D.1.1	Verify SDM is ≥ 1.6% Δk/k.	1 hour
	OR		
	D.1.2	Initiate boration to restore required SDM to within limit.	1 hour
	AND		
	D.2	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify individual rod positions within alignment limit.	12 hours AND Once within 4 hours and every 4 hours thereafter when the rod position deviation monitor is inoperable
SR 3.1.5.2	Verify rod freedom of movement (tripability) by moving each rod not fully inserted in the core ≥ 10 steps in either direction.	92 days
SR 3.1.5.3	Verify rod drop time of each rod, from the fully withdrawn position, is ≤ 2.7 seconds from the beginning of decay of stationary gripper coil voltage to dashpot entry, with: a. T_{avg} ≥ 551°F; and b. All reactor coolant pumps operating.	Prior to reactor criticality after initial fuel loading and each removal of the reactor head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.6 Shutdown Bank Insertion Limits

LCO 3.1.6 Each shutdown bank shall be within insertion limits specified in the COLR.

APPLICABILITY: MODE 1,
MODE 2 with any control bank not fully inserted.

----------NOTE----------
This LCO is not applicable while performing SR 3.1.5.2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more shutdown banks not within limits.	A.1.1	Verify SDM is ≥ 1.6% Δk/k.	1 hour
	OR		
	A.1.2	Initiate boration to restore SDM to within limit.	1 hour
	AND		
	A.2	Restore shutdown banks to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify each shutdown bank is within the limits specified in the COLR	12 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Control Bank Insertion Limits

LCO 3.1.7 Control banks shall be within the insertion, sequence, and overlap limits specified in the COLR

APPLICABILITY: MODE 1,
MODE 2 with $k_{eff} \geq 1.0$.

----------NOTE----------
This LCO is not applicable while performing SR 3.1.5.2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Control bank insertion limits not met.	A.1.1	Verify SDM is $\geq$ 1.6% $\Delta k/k$.	1 hour
	OR		
	A.1.2	Initiate boration to restore SDM to within limit.	1 hour
	AND		
	A.2	Restore control bank(s) to within limits.	2 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Control bank sequence or overlap limits not met.	B.1.1	Verify SDM is $\geq$ 1.6% Δk/k.	1 hour
	OR		
	B.1.2	Initiate boration to restore SDM to within limit.	1 hour
	AND		
	B.2	Restore control bank sequence and overlap to within limits.	2 hours
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify estimated critical control bank position is within the limits specified in the COLR.	Within 4 hours prior to achieving criticality

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.7.2	Verify each control bank insertion is within the limits specified in the COLR.	12 hours <u>AND</u> Once within 4 hours and every 4 hours thereafter when the rod insertion limit monitor is inoperable
SR 3.1.7.3	Verify sequence and overlap limits specified in the COLR are met for control banks not fully withdrawn from the core.	12 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.8 Rod Position Indication

LCO 3.1.8 The Rod Position Indication (RPI) System and the Demand Position Indication System shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each inoperable rod position indicator per group and each demand position indicator per bank.

CONDITION	REQUIRED ACTION	COMPLETION TIME
----------NOTE---------- Rod position monitoring by Required Actions A.2.1 and A.2.2 may only be applied to one inoperable RPI and shall only be allowed: (1) until the end of the current cycle, or (2) until an entry into MODE 5 of sufficient duration, whichever occurs first, when the repair of the inoperable RPI can safely be performed. Required Actions A.2.1, A.2.2 and A.2.3 shall not be allowed after the plant has been in MODE 5 or other plant condition, for a sufficient period of time, in which the repair of the inoperable RPI could have safely been performed. --- A. One RPI per group inoperable for one or more groups.	A.1 Verify the position of the rods with inoperable position indicators by using the PDMS. <u>OR</u> A.2.1 Verify the position of the rod with the inoperable position indicator by using the PDMS. <u>AND</u>	Once per 8 hours 8 hours <u>AND</u> Once every 31 days thereafter <u>AND</u> 8 hours, if rod control system parameters indicate unintended movement (continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2.2	Review the parameters of the rod control system for indications of unintended rod movement for the rod with an inoperable position indicator.	16 hours AND Once per 8 hours thereafter
	AND		
	A.2.3	Verify the position of the rod with an inoperable position indicator by using the PDMS.	8 hours, if the rod with an inoperable position indicator is moved greater than 12 steps. AND Prior to increasing THERMAL POWER above 50% RTP and within 8 hours of reaching 100% RTP
	OR		
	A.3	Reduce THERMAL POWER to less than or equal to 50% RTP.	8 hours
B. One or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction since the last determination of the rod's position.	B.1	Verify the position of the rods with inoperable position indicators by using the PDMS.	4 hours
	OR		
	B.2	Reduce THERMAL POWER to less than or equal to 50% RTP.	8 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One demand position indicator per bank inoperable for one or more banks.	C.1.1	Verify by administrative means all RPIs for the affected banks are OPERABLE.	Once per 8 hours
	AND		
	C.1.2	Verify the most withdrawn rod and the least withdrawn rod of the affected banks are less than or equal to 12 steps apart.	Once per 8 hours
	OR		
	C.2	Reduce THERMAL POWER to less than or equal to 50% RTP.	8 hours
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.8.1	Verify each RPI agrees within 12 steps of the group demand position for the full indicated range of rod travel.	18 months

3.1 REACTIVITY CONTROL SYSTEMS

3.1.9 PHYSICS TESTS Exceptions - MODE 1

LCO 3.1.9 During the performance of PHYSICS TESTS, the requirements of

LCO 3.1.5, "Rod Group Alignment Limits";
LCO 3.1.6, "Shutdown Bank Insertion Limits";
LCO 3.1.7, "Control Bank Insertion Limits";
LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and
LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)"

may be suspended, provided:

a. THERMAL POWER is maintained ≤ 85% RTP;

b. Power Range Neutron Flux - High trip setpoints are ≤ 10% RTP above the THERMAL POWER at which the test is performed, with a maximum setting of 90% RTP; and

c. SDM is ≥ 1.6% $\Delta k/k$.

APPLICABILITY: MODE 1 during PHYSICS TESTS.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. SDM not within limit.	A.1	Initiate boration to restore SDM to within limit.	15 minutes
	AND		
	A.2	Suspend PHYSICS TESTS exceptions.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. THERMAL POWER not within limit.	B.1	Reduce THERMAL POWER to within limit.	1 hour
	OR		
	B.2	Suspend PHYSICS TESTS exceptions	1 hour
C. Power Range Neutron Flux - High trip setpoints > 10% RTP above the PHYSICS TEST power level. OR Power Range Neutron Flux - High trip setpoints > 90% RTP.	C.1	Restore Power Range Neutron Flux - High trip setpoints to ≤ 10% above the PHYSICS TEST power level, or to ≤ 90% RTP, whichever is lower.	1 hour
	OR		
	C.2	Suspend PHYSICS TESTS exceptions.	1 hour

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.9.1	Verify THERMAL POWER is ≤ 85% RTP.	1 hour
SR 3.1.9.2	Verify Power Range Neutron Flux - High trip setpoints are ≤ 10% above the PHYSICS TESTS power level, and ≤ 90% RTP.	Within 8 hours prior to initiation of PHYSICS TESTS
SR 3.1.9.3	Perform SR 3.2.1.1 and SR 3.2.2.1.	12 hours
SR 3.1.9.4	Verify SDM is ≥ 1.6% $\Delta k/k$.	24 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.10 PHYSICS TESTS Exceptions - MODE 2

LCO 3.1.10 During the performance of PHYSICS TESTS, the requirements of

LCO 3.1.4, "Moderator Temperature Coefficient (MTC)";
LCO 3.1.5, "Rod Group Alignment Limits";
LCO 3.1.6, "Shutdown Bank Insertion Limits";
LCO 3.1.7, "Control Bank Insertion Limits"; and
LCO 3.4.2, "RCS Minimum Temperature for Criticality"

may be suspended, and the number of required channels for LCO 3.3.1, “RTS Instrumentation,” Functions 2, 3, 6, and 16.e, may be reduced to “3” required channels provided:

a. RCS lowest loop average temperature is ≥ 541°F; and

b. SDM is ≥ 1.6% Δk/k.

APPLICABILITY: MODE 2 during PHYSICS TESTS.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. SDM not within limit.	A.1	Initiate boration to restore SDM to within limit.	15 minutes
	AND		
	A.2	Suspend PHYSICS TESTS exceptions.	1 hour
B. THERMAL POWER not within limit.	B.1	Open reactor trip breakers.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. RCS lowest loop average temperature not within limit.	C.1	Restore RCS lowest loop average temperature to within limit.	15 minutes
D. Required Action and associated Completion Time of Condition C not met.	D.1	Be in MODE 3.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.10.1	Perform a CHANNEL OPERATIONAL TEST on power range and intermediate range channels per SR 3.3.1.7, SR 3.3.1.8, and Table 3.3.1-1.	Prior to initiation of PHYSICS TESTS
SR 3.1.10.2	Verify the RCS lowest loop average temperature is $\geq$ 541°F.	30 minutes
SR 3.1.10.3	Verify SDM is $\geq$ 1.6% $\Delta k/k$.	24 hours

3.2 POWER DISTRIBUTION LIMITS

3.2.1 Heat Flux Hot Channel Factor (F_Q (Z))

LCO 3.2.1 F_Q (Z), as approximated by F_Q^C (Z) and F_Q^W (Z), shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. F_Q^C (Z) not within limit.	A.1	Reduce THERMAL POWER ≥ 1% RTP for each 1% F_Q^C (Z) exceeds limit.	15 minutes
	AND		
	A.2	Reduce Power Range Neutron Flux – High trip setpoints ≥ 1% for each 1% F_Q^C (Z) exceeds limit.	8 hours
	AND		
	A.3	Reduce Overpower ΔT trip setpoints ≥ 1% for each 1% F_Q^C (Z) exceeds limit.	72 hours
	AND		
	A.4	Perform SR 3.2.1.1.	Prior to increasing THERMAL POWER above the limit of Required Action A.1

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. $F_Q^W(Z)$ not within limits.	B.1	Reduce AFD limits ≥ 1% for each 1% $F_Q^W(Z)$ exceeds limit.	2 hours
	AND		
		----------NOTE---------- Required Actions B.2.1, B.2.2, B.2.3, and B.2.4 not required if SR 3.2.1.2 was performed at < 75% RTP. ----------	
	B.2.1	Reduce maximum allowable power ≥ 3% RTP for each 1% $F_Q^W(Z)$ exceeds limit.	4 hours
	AND		
	B.2.2	Reduce Power Range Neutron Flux – High trip setpoints ≥ 1% for each 1% the maximum allowable power is reduced.	72 hours
	AND		
	B.2.3	Reduce Overpower ΔT trip setpoints ≥ 1% for each 1% the maximum allowable power is reduced.	72 hours
	AND		
	B.2.4	Perform SR 3.2.1.1 and SR 3.2.1.2.	Prior to increasing THERMAL POWER above the limit of Required Action B.2.1

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

----------NOTE----------
During power escalation at the beginning of each cycle, THERMAL POWER may be increased until an equilibrium power level has been achieved, at which a power distribution map is obtained.

SURVEILLANCE	FREQUENCY
SR 3.2.1.1 Verify $F_Q^C(Z)$ is within limit.	Once after initial fuel loading and each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> Once within 12 hours after achieving equilibrium conditions after exceeding, by ≥ 10% RTP, the THERMAL POWER at which $F_Q^C(Z)$ was last verified <u>AND</u> 31 EFPD thereafter

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.2.1.2	----------NOTE---------- If $F_Q^W(Z)$, increased by the appropriate factor specified in the COLR, is not within limits: Repeat SR 3.2.1.2 once per 7 EFPD using the Power Distribution Monitoring System (PDMS) until two successive incore power distribution measurements indicate Maximum over z $\left[\frac{F_Q^C(Z)}{K(Z)}\right]$ <u>AND</u> Maximum over z $\left[\frac{F_Q^C(Z)*W(Z)}{K(Z)}\right]$ have not increased. ----------	
	Verify $F_Q^W(Z)$ is within limit.	Once after initial fuel loading and each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> (continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.1.2 (continued)	Once within 12 hours after achieving equilibrium conditions after exceeding, by ≥ 10% RTP, the THERMAL POWER at which $F_Q^W(Z)$ was last verified AND 31 EFPD thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

LCO 3.2.2 $F^N_{\Delta H}$ shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. ----------NOTE---------- Required Actions A.2 and A.3 must be completed whenever Condition A is entered. ---------- $F^N_{\Delta H}$ not within limit.	A.1.1	Restore $F^N_{\Delta H}$ to within limit.	4 hours
	OR		
	A.1.2.1	Reduce THERMAL POWER to < 50% RTP.	4 hours
		AND	
	A.1.2.2	Reduce Power Range Neutron Flux - High trip setpoints to ≤ 55% RTP.	8 hours
	AND		
	A.2	Perform SR 3.2.2.1	24 hours
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 ----------NOTE---------- THERMAL POWER does not have to be reduced to comply with this Required Action. ---------- Perform SR 3.2.2.1.	Prior to THERMAL POWER exceeding 50% RTP AND Prior to THERMAL POWER exceeding 75% RTP AND 24 hours after THERMAL POWER reaching ≥ 95% RTP
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify $F^N_{\Delta H}$ is within limits specified in the COLR.	Once after initial fuel loading and each refueling prior to THERMAL POWER exceeding 75% RTP AND 31 EFPD thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.3 AXIAL FLUX DIFFERENCE (AFD)

LCO 3.2.3 The AFD in % flux difference units shall be maintained within the limits specified in the COLR.

----------NOTE----------
The AFD shall be considered outside limits when two or more OPERABLE excore channels indicate AFD to be outside limits.

APPLICABILITY: MODE 1 with THERMAL POWER ≥ 50% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. AFD not within limits.	A.1 Reduce THERMAL POWER to < 50% RTP.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.3.1	Verify AFD within limits for each OPERABLE excore channel.	7 days AND Once within 1 hour and every 1 hour thereafter with the AFD monitor alarm inoperable

3.2 POWER DISTRIBUTION LIMITS

3.2.4 QUADRANT POWER TILT RATIO (QPTR)

LCO 3.2.4 The QPTR shall be ≤ 1.02.

APPLICABILITY: MODE 1 with THERMAL POWER > 50% RTP.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. QPTR not within limit.	A.1	Reduce THERMAL POWER ≥ 3% from RTP for each 1% of QPTR > 1.00.	2 hours
	AND		
	A.2	Perform SR 3.2.4.1 and reduce THERMAL POWER ≥ 3% from RTP for each 1% of QPTR > 1.00.	Once per 12 hours thereafter
	AND		
	A.3	Perform SR 3.2.1.1 and SR 3.2.2.1.	24 hours AND Once per 7 days thereafter
	AND		
	A.4	Reevaluate safety analyses and confirm results remain valid for duration of operation under this condition.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.5	----------NOTE---------- Perform Required Action A.5 only after Required Action A.4 is completed. ---------- Calibrate excore detectors to show QPTR of 1.0.	 Prior to increasing THERMAL POWER above the limit of Required Action A.1
	<u>AND</u>		
	A.6	----------NOTE---------- Perform Required Action A.6 only after Required Action A.5 is completed. ---------- Perform SR 3.2.1.1 and SR 3.2.2.1.	 Within 24 hours after reaching RTP <u>OR</u> Within 48 hours after increasing THERMAL POWER above the limit of Required Action A.1
B. Required Action and associated Completion Time not met.	B.1	Reduce THERMAL POWER to ≤ 50% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.4.1	----------NOTES---------- a. With input from one power range neutron flux channel inoperable and THERMAL POWER < 75% RTP, the remaining three power range channels can be used for calculating QPTR. b. SR 3.2.4.2 may be performed in lieu of this Surveillance if adequate power range neutron flux channel inputs are not OPERABLE. ---------- Verify QPTR is within limit by calculation.	7 days <u>AND</u> Once within 12 hours and every 12 hours thereafter with the QPTR alarm inoperable
SR 3.2.4.2	----------NOTE---------- Only required to be performed if input from one or more power range neutron flux channels are inoperable with THERMAL POWER ≥ 75% RTP. ---------- Verify QPTR is within limit using the PDMS.	Once within 12 hours <u>AND</u> every 12 hours thereafter

3.3 INSTRUMENTATION

3.3.1 Reactor Trip System (RTS) Instrumentation

LCO 3.3.1 The RTS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.1-1 for the channel(s).	Immediately
B. One Manual Reactor Trip channel inoperable.	B.1 Restore channel to OPERABLE status.	48 hours
	OR	
	B.2.1 Be in MODE 3.	54 hours
	AND	
	B.2.2 Open reactor trip breakers (RTBs).	55 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One channel or train inoperable.	C.1 Restore channel or train to OPERABLE status.	48 hours
	OR	
	C.2 Open RTBs.	49 hours
D. One Power Range Neutron Flux-High channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 12 hours for surveillance testing and setpoint adjustment of other channels. ----------	
	D.1.1 Place channel in trip.	72 hours
	AND	
	D.1.2 Reduce THERMAL POWER to ≤ 75% RTP.	78 hours
	OR	
	D.2.1 Place channel in trip.	72 hours
	AND	
	----------NOTE---------- Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. ----------	
	D.2.2 Perform SR 3.2.4.2.	Once per 12 hours
	OR	
	D.3 Be in MODE 3.	78 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. One channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels. ----------		
	E.1	Place channel in trip.	72 hours
	OR		
	E.2	Be in MODE 3.	78 hours
F. THERMAL POWER > P-6 and < P-10, one Intermediate Range Neutron Flux channel inoperable.	F.1	Reduce THERMAL POWER to < P-6.	2 hours
	OR		
	F.2	Increase THERMAL POWER to > P-10.	2 hours
G. THERMAL POWER > P-6 and < P-10, two Intermediate Range Neutron Flux channels inoperable.	G.1	Suspend operations involving positive reactivity additions.	Immediately
	AND		
	G.2	Reduce THERMAL POWER to < P-6.	2 hours
H. THERMAL POWER < P-6, one or two Intermediate Range Neutron Flux channels inoperable.	H.1	Restore channel(s) to OPERABLE status.	Prior to increasing THERMAL POWER to > P-6
I. One Source Range Neutron Flux channel inoperable.	I.1	Suspend operations involving positive reactivity additions.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
J. Two Source Range Neutron Flux channels inoperable.	J.1	Open RTBs.	Immediately
K. One Source Range Neutron Flux channel inoperable.	K.1	Restore channel to OPERABLE status.	48 hours
	OR		
	K.2	Open RTBs.	49 hours
L. Required Source Range Neutron Flux channel inoperable.	L.1	Suspend operations involving positive reactivity additions.	Immediately
	AND		
	L.2	Close unborated water source isolation valves.	1 hour
	AND		
	L.3	Perform SR 3.1.1.1.	1 hour AND Once per 12 hours thereafter

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
M. One channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels. ---------- M.1 Place channel in trip. <u>OR</u> M.2 Reduce THERMAL POWER to < P-7.	 72 hours 78 hours
N. One Reactor Coolant Flow - Low channel inoperable.	----------NOTE---------- One channel may be bypassed for up to 12 hours for surveillance testing. ---------- N.1 Place channel in trip. <u>OR</u> N.2 Reduce THERMAL POWER to < P-7.	 72 hours 78 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
O. One Low Fluid Oil Pressure Turbine Trip channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels. ---------- O.1 Place channel in trip. <u>OR</u> O.2 Reduce THERMAL POWER to < P-9.	 72 hours 76 hours
P. One train inoperable.	----------NOTE---------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---------- P.1 Restore train to OPERABLE status. <u>OR</u> P.2 Be in MODE 3.	 24 hours 30 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
Q. One RTB train inoperable.	----------NOTE---------- One train may be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. ----------		
	Q.1	Restore train to OPERABLE status.	24 hours
	OR		
	Q.2	Be in MODE 3.	30 hours
R. One channel inoperable.	R.1	Verify interlock is in required state for existing unit conditions.	1 hour
	OR		
	R.2	Be in MODE 3.	7 hours
S. One channel inoperable.	S.1	Verify interlock is in required state for existing unit conditions.	1 hour
	OR		
	S.2	Be in MODE 2.	7 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
T. One trip mechanism inoperable for one RTB.	T.1	Restore inoperable trip mechanism to OPERABLE status.	48 hours
	OR		
	T.2.1	Be in MODE 3.	54 hours
	AND		
	T.2.2	Open RTB.	55 hours
U. One Steam Generator Water Level - Low-Low channel inoperable.	----------NOTE---------- One channel may be bypassed for up to 12 hours for surveillance testing. ----------		
	U.1.1	Place channel in trip.	72 hours
	AND		
	U.1.2	For the affected protection set, set the Trip Time Delay (T_s) to match the Trip Time Delay (T_m).	72 hours
	OR		
	U.2	Be in MODE 3.	78 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
V. One Vessel ΔT channel inoperable.	----------NOTE---------- One channel may be bypassed for up to 12 hours for surveillance testing. ---------- V.1 Set the Trip Time Delay threshold power level for (T_s) and (T_m) to 0% power. <u>OR</u> V.2 Be in MODE 3.	 72 hours 78 hours
W. One channel inoperable.	----------NOTE---------- One channel may be bypassed for up to 12 hours for surveillance testing. ---------- W.1 Place channel in trip. <u>OR</u> W.2 Be in MODE 3.	 72 hours 78 hours
X. One channel inoperable.	----------NOTE---------- One channel may be bypassed for up to 12 hours for surveillance testing. ---------- X.1 Place channel in trip. <u>OR</u> X.2 Reduce THERMAL POWER to < P-7.	 72 hours 78 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
Y. One, two or three Turbine Stop Valve Closure channels inoperable.	Y.1	Place channel(s) in trip.	72 hours
	OR		
	Y.2	Reduce THERMAL POWER to < P-9.	76 hours
Z. Two RTS Trains inoperable.	Z.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.1-1 to determine which SRs apply for each RTS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.2	----------NOTES---------- 1. Adjust NIS channel if absolute difference is > 2%. 2. Required to be performed within 12 hours after THERMAL POWER is ≥ 15% RTP. ---------- Compare results of calorimetric heat balance calculation to Nuclear Instrumentation System (NIS) channel output.	24 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.3	----------NOTES---------- 1. Adjust NIS channel if absolute difference is ≥ 3%. 2. Required to be performed within 96 hours after THERMAL POWER is ≥ 25% RTP. ---------- Compare results of the PDMS measurements to NIS AFD.	31 effective full power days (EFPD)
SR 3.3.1.4	----------NOTE---------- This Surveillance must be performed on the reactor trip bypass breaker prior to placing the bypass breaker in service. ---------- Perform TADOT.	62 days on a STAGGERED TEST BASIS
SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	92 days on a STAGGERED TEST BASIS
SR 3.3.1.6	----------NOTE---------- Required to be performed within 6 days after THERMAL POWER is ≥ 50% RTP. ---------- Calibrate excore channels to agree with the PDMS measurements.	92 EFPD

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.7	----------NOTE---------- For Functions 2 and 3 (Power Range Instrumentation), this Surveillance shall include verification that interlock P-10 is in the required state for existing unit conditions. ---------- Perform COT.	 184 days
SR 3.3.1.8	----------NOTES---------- 1. Not required to be performed for Source Range instrumentation prior to entering MODE 3 from MODE 2 until 4 hours after entry into MODE 3. 2. This Surveillance shall include verification that interlock P-6 is in the required state for existing unit conditions. ---------- Perform COT.	----------NOTE--------- Only required when not performed within previous 31 days ---------- Prior to reactor startup <u>AND</u> Four hours after reducing power below P-10 for intermediate range instrumentation <u>AND</u> Four hours after reducing power below P-6 for source range instrumentation <u>AND</u> Every 31 days thereafter

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.9	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	92 days
SR 3.3.1.10	----------NOTE---------- This Surveillance shall include verification that the time constants are adjusted to the prescribed values. ---------- Perform CHANNEL CALIBRATION.	18 months
SR 3.3.1.11	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION.	18 months
SR 3.3.1.12	Perform COT.	18 months
SR 3.3.1.13	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.14	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	Prior to exceeding the P-9 interlock whenever the unit has been in MODE 3, if not performed within the previous 31 days.
SR 3.3.1.15	----------NOTE---------- Neutron detectors are excluded from response time testing. ---------- Verify RTS RESPONSE TIME is within limits.	18 months on a STAGGERED TEST BASIS

Table 3.3.1-1 (page 1 of 9)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
1.	Manual Reactor Trip	1, 2	2	B	SR 3.3.1.13	NA	NA
		3 [a], 4 [a], 5 [a]	2	C	SR 3.3.1.13	NA	NA
2.	Power Range Neutron Flux						
	a. High	1, 2	4	D	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 [b][c] SR 3.3.1.11 [b][c] SR 3.3.1.15	≤ 111.4% RTP	109% RTP
	b. Low	1 [d], 2	4	E	SR 3.3.1.1 SR 3.3.1.7 [b][c] SR 3.3.1.11 [b][c] SR 3.3.1.15	≤ 27.4% RTP	25% RTP
3.	Power Range Neutron Flux Rate						
	a. High Positive Rate	1, 2	4	E	SR 3.3.1.7 [b][c] SR 3.3.1.11 [b][c]	≤ 6.3% RTP with time constant ≥ 2 sec	5% RTP with time constant ≥ 2 sec
	b. High Negative Rate – DELETED						
4.	Intermediate Range Neutron Flux	1 [d], 2 [e]	2	F, G	SR 3.3.1.1 SR 3.3.1.8 [b][c] SR 3.3.1.11 [b][c]	≤ 40% RTP	25% RTP
		2 [f]	2	H	SR 3.3.1.1 SR 3.3.1.8 [b][c] SR 3.3.1.11 [b][c]	≤ 40% RTP	25% RTP

(continued)

(a) With Reactor Trip Breakers (RTBs) closed and Rod Control System capable of rod withdrawal.

(b) If the as found channel setpoint is outside its predefined as found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(c) The instrument channel setpoint shall be reset to a value that is within the as left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. The methodologies used to determine the as found and as left tolerances for the NTSP are specified in FSAR Section 7.1.2.

(d) Below the P-10 (Power Range Neutron Flux) interlocks.

(e) Above the P-6 (Intermediate Range Neutron Flux) interlocks.

(f) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

Table 3.3.1-1 (page 2 of 9)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
5.	Source Range Neutron Flux	2 [f]	2	I, J	SR 3.3.1.1 SR 3.3.1.8 [b][c] SR 3.3.1.11 [b][c]	≤ 1.33 E5 cps	1.0 E5 cps
		3 [a], 4 [a], 5 [a]	2	J, K	SR 3.3.1.1 SR 3.3.1.8 [b][c] SR 3.3.1.11 [b][c] SR 3.3.1.15	≤ 1.33 E5 cps	1.0 E5 cps
		3 [g], 4 [g], 5 [g]	1	L	SR 3.3.1.1 SR 3.3.1.11 [b][c]	N/A	N/A
6.	Overtemperature ΔT	1, 2	4	W	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7 [b][c] SR 3.3.1.10 [b][c] SR 3.3.1.15	Refer to Note 1 (Page 3.3-21)	Refer to Note 1 (Page 3.3-21)
7.	Overpower ΔT	1, 2	4	W	SR 3.3.1.1 SR 3.3.1.7 [b][c] SR 3.3.1.10 [b][c] SR 3.3.1.15	Refer to Note 2 (Page 3.3-22)	Refer to Note 2 (Page 3.3-22)
8.	Pressurizer Pressure						
	a. Low	1 [h]	4	X	SR 3.3.1.1 SR 3.3.1.7 [b][c] SR 3.3.1.10 [b][c] SR 3.3.1.15	≥ 1964.8 psig	1970 psig
	b. High	1, 2	4	W	SR 3.3.1.1 SR 3.3.1.7 [b][c] SR 3.3.1.10 [b][c] SR 3.3.1.15	≤ 2390.2 psig	2385 psig

(continued)

(a) With Reactor Trip Breakers (RTBs) closed and Rod Control System capable of rod withdrawal.

(b) If the as found channel setpoint is outside its predefined as found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(c) The instrument channel setpoint shall be reset to a value that is within the as left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. The methodologies used to determine the as found and as left tolerances for the NTSP are specified in FSAR Section 7.1.2.

(f) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

(g) With the RTBs open. In this condition, source range Function does not provide reactor trip but does provide indication.

(h) Above the P-7 (Low Power Reactor Trips Block) interlock.

Table 3.3.1-1 (page 3 of 9)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
9.	Pressurizer Water Level-High	1 [h]	3	X	SR 3.3.1.1 SR 3.3.1.7 [b][c] SR 3.3.1.10 [b][c]	≤ 92.7% span	92% span
10.	Reactor Coolant Flow - Low	1 [h]	3 per loop	N	SR 3.3.1.1 SR 3.3.1.7 [b][c] SR 3.3.1.10 [b][c] SR 3.3.1.15	≥ 89.7% flow	90% flow
11.	Undervoltage RCPs	1 [h]	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10 [b][c] SR 3.3.1.15	≥ 5112 V	5400 V
12.	Underfrequency RCPs	1 [h]	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10 [b][c] SR 3.3.1.15	≥ 56.9 Hz	57.5 Hz

(continued)

(b) If the as found channel setpoint is outside its predefined as found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(c) The instrument channel setpoint shall be reset to a value that is within the as left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. The methodologies used to determine the as found and as left tolerances for the NTSP are specified in FSAR Section 7.1.2.

(h) Above the P-7 (Low Power Reactor Trips Block) interlock.

Table 3.3.1-1 (page 4 of 9)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
13. SG Water Level – Low-Low	1, 2	3/SG	U	SR 3.3.1.1 SR 3.3.1.7 [b][c] SR 3.3.1.10 [b][c] SR 3.3.1.15	≥ 16.4% of narrow range span	17% of narrow range span
Coincident with:						
a) Vessel ΔT Equivalent to power ≤ 50% RTP	1, 2	3	V	SR 3.3.1.7 [b][c] SR 3.3.1.10 [b][c]	Vessel ΔT variable input ≤ 52.6% RTP	Vessel ΔT variable input 50% RTP
With a time delay (T_s) if one steam generator is affected					≤ 1.01 T_s (Refer to Note 3, Page 3.3-23)	T_s (Refer to Note 3, Page 3.3-23)
or						
A time delay (T_m) if two or more steam generators are affected					≤ 1.01 T_m (Refer to Note 3, Page 3.3-23)	T_m (Refer to Note 3, Page 3.3-23)
b) Vessel ΔT Equivalent to power > 50% RTP with no time delay (T_s and T_m = 0)	1, 2	3	V	SR 3.3.1.7 [b][c] SR 3.3.1.10 [b][c]	Vessel ΔT variable input ≤ 52.6% RTP	Vessel ΔT variable input 50% RTP
14. Turbine Trip						
a. Low Fluid Oil Pressure	1 [i]	3	O	SR 3.3.1.10 [b][c] SR 3.3.1.14	≥ 38.3 psig	45 psig
b. Turbine Stop Valve Closure	1 [i]	4	Y	SR 3.3.1.10 SR 3.3.1.14	≥ 1% open	1% open

(continued)

(b) If the as found channel setpoint is outside its predefined as found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(c) The instrument channel setpoint shall be reset to a value that is within the as left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. The methodologies used to determine the as found and as left tolerances for the NTSP are specified in FSAR Section 7.1.2.

(i) Above the P-9 (Power Range Neutron Flux) interlock.

Table 3.3.1-1 (page 5 of 9)
Reactor Trip System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
15. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1, 2	2 trains	P	SR 3.3.1.13	NA	NA
16. Reactor Trip System Interlocks						
a. Intermediate Range Neutron Flux, P-6						
(1) Enable Manual Block of SR Trip	2 [f]	2	R	SR 3.3.1.11 SR 3.3.1.12	NA	1.66E-04% RTP
(2) Auto Reset (Unblock Manual Block of SR Trip)	2 [f]	2	R	SR 3.3.1.11 SR 3.3.1.12	≥ 7.65E-5% RTP	0.47E-4% RTP below setpoint
b. Low Power Reactor Trips Block, P-7	1	1 per train	S	SR 3.3.1.11 SR 3.3.1.12	NA	NA
c. Power Range Neutron Flux, P-8	1	4	S	SR 3.3.1.11 SR 3.3.1.12	≤ 50.4% RTP	48% RTP
d. Power Range Neutron Flux, P-9	1	4	S	SR 3.3.1.11 SR 3.3.1.12	≤ 52.4% RTP	50% RTP
e. Power Range Neutron Flux, P-10	1, 2	4	R	SR 3.3.1.11 SR 3.3.1.12	≥ 7.6% RTP and ≤ 12.4% RTP	10% RTP
f. Turbine Impulse Pressure, P-13	1	2	S	SR 3.3.1.10 SR 3.3.1.12	≤ 12.4% full-power pressure	10% full-power pressure

(continued)

(f) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

Table 3.3.1-1 (page 6 of 9)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOW-ABLE VALUE	NOMINAL TRIP SETPOINT
17.	Reactor Trip Breakers [j]	1, 2	2 trains	Q	SR 3.3.1.4	NA	NA
		3 [a], 4 [a], 5 [a]	2 trains	C	SR 3.3.1.4	NA	NA
18.	Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1, 2	1 each per RTB	T	SR 3.3.1.4	NA	NA
		3 [a], 4 [a], 5 [a]	1 each per RTB	C	SR 3.3.1.4	NA	NA
19.	Automatic Trip Logic	1, 2	2 trains	P	SR 3.3.1.5	NA	NA
		3 [a], 4 [a], 5 [a]	2 trains	C	SR 3.3.1.5	NA	NA

(a) With Reactor Trip Breakers (RTBs) closed and Rod Control System capable of rod withdrawal.

(j) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.1-1 (page 7 of 9)
Reactor Trip System Instrumentation

Note 1: Overtemperature ΔT

The Overtemperature ΔT Function Allowable Value shall not exceed the following Trip Setpoint by more than 1.2% of ΔT span.

$$\Delta T\left\{\frac{1+\tau_4 s}{1+\tau_5 s}\right\} \leq \Delta T_0\left\{K_1 - K_2\,\frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left[T - T'\right] + K_3\left(P - P'\right) - f_1(\Delta I)\right\}$$

Where: ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T′ is the indicated T_{avg} at RTP, ≤ 588.2°F.

P is the measured pressurizer pressure, psig
P′ is the nominal RCS operating pressure, ≥ 2235 psig

$K_1 \leq 1.16$	$K_2 \geq 0.0183/°F$	$K_3 = 0.000900/psig$
$\tau_1 \geq 33$ sec	$\tau_2 \leq 4$ sec	
$\tau_4 \geq 3$ sec	$\tau_5 \leq 3$ sec	

$f_1(\Delta I)$	=	$-2.62\{22 + (q_t - q_b)\}$	when $q_t - q_b < -22\%$ RTP
		0	when -22% RTP $\leq q_t - q_b \leq 10\%$ RTP
		$1.96\{(q_t - q_b) - 10\}$	when $q_t - q_b > 10\%$ RTP

Where q_t and q_b are percent RTP in the upper and lower halves of the core, respectively, and $q_t + q_b$ is the total THERMAL POWER in percent RTP.

Table 3.3.1-1 (page 8 of 9)
Reactor Trip System Instrumentation

Note 2: Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following Trip Setpoint by more than 1.0% of ΔT span.

$$\Delta T\left\{\frac{1+\tau_4 s}{1+\tau_5 s}\right\} \leq \Delta T_0\left\{K_4 - K_5\,\frac{(\tau_3 s)}{(1+\tau_3 s)}[T] - K_6\left(T - T''\right) - f_2(\Delta I)\right\}$$

Where: ΔT is measured RCS ΔT, °F.

ΔT_0 is the indicated ΔT at RTP, °F.

s is the Laplace transform operator, sec^{-1}.

T is the measured RCS average temperature, °F.

T′′ is the indicated T_{avg} at RTP, ≤ 588.2°F.

$K_4 \leq 1.10$	$K_5 \geq$	0.02/°F for increasing T_{avg} 0/°F for decreasing T_{avg}	$K_6 \geq$	0.00162/°F when T > T″ 0/°F when T ≤ T″	
$\tau_3 \geq$ 5 sec	$\tau_4 \geq$	3 sec	$\tau_5 \leq$	3 sec	

$f_2(\Delta I) = 0$ for all ΔI.

Table 3.3.1-1 (page 9 of 9)
Reactor Trip System Instrumentation

NOTE 3: Steam Generator Water Level Low-Low Trip Time Delay:

$$T_s = A(P)^3 + B(P)^2 + C(P) + D$$

$$T_m = E(P)^3 + F(P)^2 + G(P) + H$$

Where:

P = Vessel ΔT Equivalent to power (% RTP), $P \leq 50\%$ RTP

T_s = Time Delay for Steam Generator Water Level – Low Low Reactor Trip, one Steam Generator affected.

T_m = Time Delay for Steam Generator Water Level – Low Low Reactor Trip, two or more Steam Generators affected.

A = -0.0085041

B = 0.9266400

C = -33.85998

D = 474.6060

E = -0.0047421

F = 0.5682600

G = -23.70753

H = 357.9840

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or train(s).	Immediately
B. One channel or train inoperable.	B.1 Restore channel or train to OPERABLE status.	48 hours
	OR	
	B.2.1 Be in MODE 3.	54 hours
	AND	
	B.2.2 Be in MODE 5.	84 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One train inoperable.	C.1	----------NOTE---------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---------- Restore train to OPERABLE status.	24 hours
	OR		
	C.2.1	Be in MODE 3.	30 hours
	AND		
	C.2.2	Be in MODE 5.	60 hours
D. One channel inoperable.	D.1	----------NOTE---------- One channel may be bypassed for up to 12 hours for surveillance testing. ---------- Place channel in trip.	72 hours
	OR		
	D.2.1	Be in MODE 3.	78 hours
	AND		
	D.2.2	Be in MODE 4.	84 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. One Containment Pressure channel inoperable.	E.1	----------NOTE---------- One channel may be bypassed for up to 12 hours for surveillance testing. ----------	
		Place channel in bypass.	72 hours
	OR		
	E.2.1	Be in MODE 3.	78 hours
	AND		
	E.2.2	Be in MODE 4.	84 hours
F. One channel or train inoperable.	F.1	Restore channel or train to OPERABLE status.	48 hours
	OR		
	F.2.1	Be in MODE 3.	54 hours
	AND		
	F.2.2	Be in MODE 4.	60 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
G. One train inoperable.	G.1	----------NOTE---------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---------- Restore train to OPERABLE status.	24 hours
	OR		
	G.2.1	Be in MODE 3.	30 hours
	AND		
	G.2.2	Be in MODE 4.	36 hours
H. One train inoperable.	H.1	----------NOTE---------- One train may be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. ---------- Restore train to OPERABLE status.	24 hours
	OR		
	H.2.1	Be in MODE 3.	30 hours
	AND		
	H.2.2	Be in MODE 4.	36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
I. One Steam Generator Water Level – High High channel inoperable.	I.1	----------NOTE---------- One channel may be bypassed for up to 12 hours for surveillance testing. ---------- Place channel in trip.	 72 hours
	OR		
	I.2.1	Be in MODE 3.	78 hours
	AND		
	I.2.2	Be in MODE 4.	84 hours
J. One or more Turbine Driven Main Feedwater Pump trip channel(s) inoperable.	J.1	Restore channel to OPERABLE status.	48 hours
	OR		
	J.2	Be in MODE 3.	54 hours
K. One channel inoperable.	K.1	----------NOTE---------- One channel may be bypassed for up to 12 hours for surveillance testing. ---------- Place channel in bypass.	 72 hours
	OR		
	K.2.1	Be in MODE 3.	78 hours
	AND		
	K.2.2	Be in MODE 5.	108 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
L. One P-11 interlock channel inoperable.	L.1 Verify interlock is in required state for existing unit condition.	1 hour
	OR	
	L.2.1 Be in MODE 3.	7 hours
	AND	
	L.2.2 Be in MODE 4.	13 hours
M. One Steam Generator Water Level – Low-Low channel inoperable.	----------NOTE---------- One channel may be bypassed for up to 12 hours for surveillance testing. ----------	
	M.1.1 Place channel in trip.	72 hours
	AND	
	M.1.2 For the affected protection set, set the Trip Time Delay (T_s) to match the Trip Time Delay (T_m).	72 hours
	OR	
	M.2.1 Be in MODE 3.	78 hours
	AND	
	M.2.2 Be in MODE 4.	84 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
N. One Vessel ΔT channel inoperable.	----------NOTE---------- One channel may be bypassed for up to 12 hours for surveillance testing. ---------- N.1 Set the Trip Time Delay threshold power level for (T_s) and (T_m) to 0% power. OR N.2 Be in MODE 3.	 72 hours 78 hours
O. One MSVV Room Water Level High channel inoperable.	----------NOTE---------- The inoperable channel may be bypassed for up to 12 hours for surveillance testing of other channels. ---------- O.1 Place channel in trip. OR O.2 Be in MODE 3.	 72 hours 78 hours

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	92 days on a STAGGERED TEST BASIS
SR 3.3.2.3	Perform MASTER RELAY TEST.	92 days on a STAGGERED TEST BASIS
SR 3.3.2.4	Perform COT.	184 days
SR 3.3.2.5	----------NOTE---------- Slave relays tested by SR 3.3.2.7 are excluded from this surveillance. --- Perform SLAVE RELAY TEST.	92 days <u>OR</u> 18 months for Westinghouse type AR and Potter & Brumfield MDR Series relays

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.6	----------NOTE---------- Verification of relay setpoints not required. ---------- Perform TADOT.	92 days
SR 3.3.2.7	Perform SLAVE RELAY TEST on slave relays K603A, K603B, K604A, K604B, K607A, K607B, K609A, K609B, K612A, K625A, and K625B.	18 months
SR 3.3.2.8	----------NOTE---------- Verification of setpoint not required for manual initiation. ---------- Perform TADOT.	18 months
SR 3.3.2.9	----------NOTE---------- This Surveillance shall include verification that the time constants are adjusted to the prescribed values. ---------- Perform CHANNEL CALIBRATION.	18 months
SR 3.3.2.10	----------NOTE---------- Not required to be performed for the turbine driven AFW pump until 24 hours after ≥ 1092 psig in the steam generator. ---------- Verify ESFAS RESPONSE TIMES are within limit.	18 months on a STAGGERED TEST BASIS

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.11	----------NOTE---------- Verification of setpoint not required. ---------- Perform TADOT.	Once per reactor trip breaker cycle

SURVEILLANCE REQUIREMENTS (continued)

Table 3.3.2-1 (page 1 of 8)
Engineered Safety Feature Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
1.	Safety Injection						
a.	Manual Initiation	1, 2, 3, 4	2	B	SR 3.3.2.8	NA	NA
b.	Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5 SR 3.3.2.7	NA	NA
c.	Containment Pressure – High	1, 2, 3	3	D	SR 3.3.2.1 SR 3.3.2.4 [(b) (c)] SR 3.3.2.9 [(b) (c)] SR 3.3.2.10	≤ 1.6 psig	1.5 psig
d.	Pressurizer Pressure – Low	1, 2, 3[(a)]	3	D	SR 3.3.2.1 SR 3.3.2.4 [(b) (c)] SR 3.3.2.9 [(b) (c)] SR 3.3.2.10	≥ 1864.8 psig	1870 psig
e.	Steam Line Pressure - Low	1, 2, 3[(a)]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 [(b) (c)] SR 3.3.2.9 [(b) (c)] SR 3.3.2.10	≥ 666.6[(d)] psig	675[(d)] psig
2.	Containment Spray						
a.	Manual Initiation	1, 2, 3, 4	2 per train, 2 trains	B	SR 3.3.2.8	NA	NA
b.	Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA	NA
c.	Containment Pressure – High High	1, 2, 3	4	E	SR 3.3.2.1 SR 3.3.2.4 [(b) (c)] SR 3.3.2.9 [(b) (c)] SR 3.3.2.10	≤2.9 psig	2.8 psig

(continued)

(a) Above the P-11 (Pressurizer Pressure) Interlock.

(b) If the as found channel setpoint is outside its redefined as found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(c) The instrument channel setpoint shall be reset to a value that is within the as left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. The methodologies used to determine the as found and as left tolerances for the NTSP are specified in FSAR Section 7.1.2.

(d) Time constants used in the lead/lag controller are $t_1 \geq 50$ seconds and $t_2 \leq 5$ seconds.

SURVEILLANCE REQUIREMENTS (continued)

Table 3.3.2-1 (page 2 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
3. Containment Isolation						
a. Phase A Isolation						
1) Manual Initiation	1, 2, 3, 4	2	B	SR 3.3.2.8	NA	NA
2) Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5 SR 3.3.2.7	NA	NA
3) Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
b. Phase B Isolation						
1) Manual Initiation	1, 2, 3, 4	2 per train, 2 trains	B	SR 3.3.2.8	NA	NA
2) Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5 SR 3.3.2.7	NA	NA
3) Containment Pressure – High High	1, 2, 3	4	E	SR 3.3.2.1 SR 3.3.2.4 [(b) (c)] SR 3.3.2.9 [(b) (c)] SR 3.3.2.10	≤2.9 psig	2.8 psig

(continued)

(b) If the as found channel setpoint is outside its redefined as found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(c) The instrument channel setpoint shall be reset to a value that is within the as left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. The methodologies used to determine the as found and as left tolerances for the NTSP are specified in FSAR Section 7.1.2.

SURVEILLANCE REQUIREMENTS (continued)

Table 3.3.2-1 (page 3 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
4. Steam Line Isolation						
a. Manual Initiation	1, 2 [e], 3 [e]	1/valve	F	SR 3.3.2.8	NA	NA
b. Automatic Actuation Logic and Actuation Relays	1, 2 [e], 3 [e]	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA	NA
c. Containment Pressure – High High	1, 2 [e], 3 [e]	4	E	SR 3.3.2.1 SR 3.3.2.4 [b] [c] SR 3.3.2.9 [b] [c] SR 3.3.2.10	≤ 2.9 psig	2.8 psig
d. Steam Line Pressure						
1) Low	1, 2 [e], 3 [a][e]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 [b] [c] SR 3.3.2.9 [b] [c] SR 3.3.2.10	≥ 666.6 [d] psig	675 [d] psig
2) Negative Rate - High	3 [e][f]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 [b] [c] SR 3.3.2.9 [b] [c] SR 3.3.2.10	≤ 108.5 [g] psi	100 [g] psi

(continued)

(a) Above the P-11 (Pressurizer Pressure) Interlock.

(b) If the as found channel setpoint is outside its redefined as found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(c) The instrument channel setpoint shall be reset to a value that is within the as left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. The methodologies used to determine the as found and as left tolerances for the NTSP are specified in FSAR Section 7.1.2.

(d) Time constants used in the lead/lag controller are $t_1 \geq 50$ seconds and $t_2 \leq 5$ seconds.

(e) Except when all MSIVs are closed and de-activated.

(f) Function automatically blocked above P-11 (Pressurizer Interlock) setpoint and is enabled below P-11 when safety injection on Steam Line Pressure Low is manually blocked.

(g) Time constants utilized in the rate/lag controller are t_3 and $t_4 \geq 50$ seconds.

SURVEILLANCE REQUIREMENTS (continued)

Table 3.3.2-1 (page 4 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
5. Turbine Trip and Feedwater Isolation						
a. Automatic Actuation Logic and Actuation Relays	1, 2 [h], 3 [h]	2 trains	H	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA	NA
b. SG Water Level – High High (P-14)	1, 2 [h], 3 [h]	3 per SG	I	SR 3.3.2.1 SR 3.3.2.4 [b] [c] SR 3.3.2.9 [b] [c] SR 3.3.2.10	≤83.1%	82.4%
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
d. North MSV Vault Room Water Level – High	1, 2 [h][i]	3 per vault room	O	SR 3.3.2.6 SR 3.3.2.9	≤ 5.31 inches	4 inches
e. South MSV Vault Room Water Level – High	1, 2 [h][i]	3 per vault room	O	SR 3.3.2.6 SR 3.3.2.9	≤ 4.56 inches	4 inches

(continued)

(b) If the as found channel setpoint is outside its redefined as found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(c) The instrument channel setpoint shall be reset to a value that is within the as left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. The methodologies used to determine the as found and as left tolerances for the NTSP are specified in FSAR Section 7.1.2.

(h) Except when all MFIVs, MFRVs, and associated bypass valves are closed and de-activated or isolated by a closed manual valve.

(i) MODE 2 if Turbine Driven Main Feed Pumps are operating.

SURVEILLANCE REQUIREMENTS (continued)

Table 3.3.2-1 (page 5 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
6. Auxiliary Feedwater						
a. Automatic Actuation Logic and Actuation Relays	1, 2, 3	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA	NA
b. SG Water Level – Low Low	1, 2, 3	3 per SG	M	SR 3.3.2.1 SR 3.3.2.4 [(b) (c)] SR 3.3.2.9 [(b) (c)] SR 3.3.2.10	≥ 16.4%	17.0%
Coincident with:						
1) Vessel ΔT Equivalent to power ≤ 50% RTP	1, 2	3	N	SR 3.3.2.4 [(b) (c)] SR 3.3.2.9 [(b) (c)]	Vessel ΔT variable input ≤ 52.6% RTP	Vessel ΔT variable input 50% RTP
With a time delay (T_s) if one SG is affected					≤ 1.01 T_s (Note 1, Page 3.3-40)	T_s (Note 1, Page 3.3-40)
or						
A time delay (T_m) if two or more SGs are affected					≤ 1.01 T_m (Note 1, Page 3.3-40)	T_m (Note 1, Page 3.3-40)
OR						
2) Vessel ΔT equivalent to power > 50% RTP with no time delay (T_s and T_m = 0)	1, 2	3	N	SR 3.3.2.4 [(b) (c)] SR 3.3.2.9 [(b) (c)]	Vessel ΔT variable input ≤ 52.6% RTP	Vessel ΔT variable input 50% RTP
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					

(continued)

(b) If the as found channel setpoint is outside its redefined as found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(c) The instrument channel setpoint shall be reset to a value that is within the as left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. The methodologies used to determine the as found and as left tolerances for the NTSP are specified in FSAR Section 7.1.2.

SURVEILLANCE REQUIREMENTS (continued)

Table 3.3.2-1 (page 6 of 8)
Engineered Safety Feature Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
6.	Auxiliary Feedwater (continued)						
d.	Loss of Offsite Power	1, 2, 3	4 per bus	F	Refer to Function 4 of Table 3.3.5-1 for SRs and Allowable Values. Notes (b) and (c) are applicable to SR 3.3.5.2 for this function.		
e.	Trip of all Turbine Driven Main Feedwater Pumps	1 [(j)], 2 [(k)]	1 per pump	J	SR 3.3.2.8 [(b)(c)] SR 3.3.2.9 [(b) (c)] SR 3.3.2.10	≥43.3 psig	50 psig
f.	Auxiliary Feedwater Pumps Train A and B Suction Transfer on Suction Pressure - Low	1, 2, 3, 4[(m)]	3	B	SR 3.3.2.6 SR 3.3.2.9 [(b) (c)] SR 3.3.2.10	A) ≥ 0.5 psig B) ≥ 1.33 psig	A) 1.2 psig B) 2.0 psig
7.	Automatic Switchover to Containment Sump						
a.	Automatic Actuation Logic and Actuation Relays	1, 2, 3, 4	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA	NA
b.	Refueling Water Storage Tank (RWST) Level - Low	1, 2, 3, 4	4	K	SR 3.3.2.1 SR 3.3.2.4 [(b) (c)] SR 3.3.2.9 [(b) (c)] SR 3.3.2.10	≥155.6 inches from Tank Base	158 inches from Tank Base
	Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
	and						
	Coincident with Containment Sump Level - High	1, 2, 3, 4	4	K	SR 3.3.2.1 SR 3.3.2.4 [(b) (c)] SR 3.3.2.9 [(b) (c)] SR 3.3.2.10	≥ 37.2 inches above el. 702.8 ft	38.2 inches above el. 702.8 ft

(continued)

(b) If the as found channel setpoint is outside its redefined as found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(c) The instrument channel setpoint shall be reset to a value that is within the as left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. The methodologies used to determine the as found and as left tolerances for the NTSP are specified in FSAR Section 7.1.2.

(j) Entry into Condition J may be suspended for up to 4 hours when placing the second Turbine Driven Main Feedwater (TDMFW) Pump in service or removing one of two TDMFW pumps from service.

(k) When one or more Turbine Driven Feedwater Pump(s) are supplying feedwater to steam generators.

(m) When steam generators are being relied on for heat removal.

SURVEILLANCE REQUIREMENTS (continued)

Table 3.3.2-1 (page 7 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
8. ESFAS Interlocks						
a. Reactor Trip, P-4	1, 2, 3	1 per train, 2 trains	F	SR 3.3.2.11	NA	NA
b. Pressurizer Pressure, P-11						
(1) Unblock (Auto Reset of SI Block)	1, 2, 3	3	L	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.9	≤ 1975.2 psig	1970 psig
(2) Enable Manual Block of SI	1, 2, 3	3	L	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.9	≥ 1956.8 psig	1962 psig

SURVEILLANCE REQUIREMENTS (continued)

Table 3.3.2-1 (page 8 of 8)
Engineered Safety Feature Actuation System Instrumentation

NOTE 1: Steam Generator Water Level Low-Low Trip Time Delay:

$$T_s = A(P)^3 + B(P)^2 + C(P) + D$$

$$T_m = E(P)^3 + F(P)^2 + G(P) + H$$

Where:

P = Vessel ΔT Equivalent to power (% RTP), P ≤ 50% RTP.

T_s = Time Delay for Steam Generator Water Level – Low Low Reactor Trip, one Steam Generator affected.

T_m = Time Delay for Steam Generator Water Level – Low Low Reactor Trip, two or more Steam Generators affected.

A = -0.0085041

B = 0.9266400

C = -33.85998

D = 474.6060

E = -0.0047421

F = 0.5682600

G = -23.70753

H = 357.9840

3.3 INSTRUMENTATION

3.3.3 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3 The PAM instrumentation for each Function in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.3-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ----------NOTE---------- Not applicable to Functions 3, 4, 14, and 16. ---------- 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 5.9.8.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more Functions with two required channels inoperable. <u>OR</u> Functions 3, 4, 14, and 16 with one required channel inoperable.	C.1	Restore one channel to OPERABLE status.	7 days
D. Required Action and associated Completion Time of Condition C not met.	D.1	Enter the Condition referenced in Table 3.3.3-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.3-1.	E.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	E.2	Be in MODE 4.	12 hours
F. As required by Required Action D.1 and referenced in Table 3.3.3-1.	F.1	Initiate action in accordance with Specification 5.9.8.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.3.2	----------NOTES---------- 1. Neutron detectors are excluded from CHANNEL CALIBRATION. 2. Not applicable to Functions 11 and 16. --- Perform CHANNEL CALIBRATION.	18 months
SR 3.3.3.3	----------NOTES---------- 1. Verification of relay setpoints not required. 2. Only applicable to Functions 11 and 16. --- Perform TADOT.	18 months

Table 3.3.3-1 (page 1 of 3)
Post Accident Monitoring Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS / TRAINS	CONDITION REFERENCED FROM REQUIRED ACTION D.1
1)	Intermediate Range Neutron Flux [g]	1[a], 2[b], 3	2	E
2)	Source Range Neutron Flux	2[c] , 3	2	E
3)	Reactor Coolant System (RCS) Hot Leg Temperature (T-Hot)	1, 2, 3	1 per loop	E
4)	RCS Cold Leg Temperature (T-Cold)	1, 2, 3	1 per loop	E
5)	RCS Pressure (Wide Range)	1, 2, 3	3	E
6)	Reactor Vessel Water Level [f][g]	1, 2, 3	2	F
7)	Containment Sump Water Level (Wide Range)	1, 2, 3	2	E
8)	Containment Lower Comp. Atm. Temperature	1, 2, 3	2	E
9)	Containment Pressure (Wide Range) [g]	1, 2, 3	2	E
10)	Containment Pressure (Narrow Range)	1, 2, 3	4	E
11)	Containment Isolation Valve Position [g]	1, 2, 3	2 per penetration flow path [d][i]	E
12)	Containment Radiation (High Range)	1, 2, 3	2 upper containment 2 lower containment	F
13)	RCS Pressurizer Level	1, 2, 3	3	E
14)	Steam Generator (SG) Water Level (Wide Range) [g]	1, 2, 3	1/SG	E

(continued)

Table 3.3.3-1 (page 2 of 3)
Post Accident Monitoring Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS / TRAINS	CONDITION REFERENCED FROM REQUIRED ACTION D.1
15)	Steam Generator Water Level (Narrow Range)	1, 2, 3	3/SG	E
16)	AFW Valve Status [j]	1, 2, 3	1 per valve	E
17)	Core Exit Temperature-Quadrant 1[f]	1, 2, 3	2 [e]	E
18)	Core Exit Temperature-Quadrant 2[f]	1, 2, 3	2 [e]	E
19)	Core Exit Temperature-Quadrant 3[f]	1, 2, 3	2 [e]	E
20)	Core Exit Temperature-Quadrant 4[f]	1, 2, 3	2 [e]	E
21)	Auxiliary Feedwater Flow	1, 2, 3	2/SG	E
22)	Reactor Coolant System Subcooling Margin Monitor [h]	1, 2, 3	2	E
23)	Refueling Water Storage Tank Water Level	1, 2, 3	2	E
24)	Steam Generator Pressure	1, 2, 3	2/SG	E
25)	Auxiliary Building Passive Sump Level [j]	1, 2, 3	2	E

Table 3.3.3-1 (page 3 of 3)
Post Accident Monitoring Instrumentation

(a) Below the P-10 (Power Range Neutron Flux) interlocks.

(b) Above the P-6 (Intermediate Range Neutron Flux) interlocks.

(c) Below the P-6 (Intermediate Range Neutron Flux) interlocks

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

(e) A channel consists of two core exit thermocouples (CETs).

(f) The Common Q Post Accident Monitoring System provides these functions on a flat screen display.

(g) Regulatory Guide 1.97, non-Type A, Category 1 Variables.

(h) This function is displayed on the Common Q Post Accident Monitoring System flat screen display and digital panel meters.

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

(j) Watts Bar specific (not required by Regulatory Guide 1.97) non-Type A Category 1 variable.

3.3 INSTRUMENTATION

3.3.4 Remote Shutdown System

LCO 3.3.4 The Remote Shutdown System Functions in Table 3.3.4-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required Functions inoperable.	A.1	Restore required Function to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.4.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.4.2	Verify each required control circuit and transfer switch is capable of performing the intended function.	18 months
SR 3.3.4.3	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION for each required instrumentation channel.	18 months
SR 3.3.4.4	Perform TADOT of the reactor trip breaker open/closed indication.	18 months

Table 3.3.4-1 (page 1 of 1)
Remote Shutdown System Instrumentation and Controls

FUNCTION/INSTRUMENT OR CONTROL PARAMETER	REQUIRED NUMBER OF FUNCTIONS
1. Reactivity Control	
a. Source Range Neutron Flux	1
b. Reactor Trip Breaker Position Indication	1 per trip breaker
2. Reactor Coolant System (RCS) Pressure Control	
a. Pressurizer Pressure Indication or RCS Wide Range Pressure Indication	1
b. Pressurizer Power Operated Relief Valve (PORV) Control and Pressurizer Block Valve Control	1 each per relief path
c. Pressurizer Heater Control	1
3. RCS Inventory Control	
a. Pressurizer Level Indication	1
b. Charging and Letdown Flow Control and Indication	1
4. Decay Heat Removal via Steam Generators (SGs)	
a. RCS Hot Leg Temperature Indication	1 per loop
b. AFW Controls	1
c. SG Pressure Indication and Control	1 per SG
d. SG Level Indication and AFW Flow Indication	1 per SG
e. SG T_{sat} Indication	1 per SG
5. Decay Heat Removal via RHR System	
a. RHR Flow Control	1
b. RHR Temperature Indication	1

3.3 INSTRUMENTATION

3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

LCO 3.3.5 The LOP DG Start Instrumentation for each Function in Table 3.3.5-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4,
When associated DG is required to be OPERABLE by LCO 3.8.2, "AC Sources-Shutdown."

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel per bus inoperable.	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.3.2, "ESFAS Instrumentation," for Auxiliary Feedwater Start Instrumentation made inoperable by LOP DG Start Instrumentation. ---------- A.1 Restore channel to OPERABLE status.	6 hours
B. One or more Functions with two or more channels per bus inoperable.	B.1 Restore all but one channel to OPERABLE status.	1 hour

(continued)

ACTIONS continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1 Enter applicable Condition(s) and Required Action(s) for the associated DG made inoperable by LOP DG start instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.5-1 to determine which SRs apply for each LOP Function.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	----------NOTE---------- Verification of relay setpoints not required. ---------- Perform TADOT.	92 days
SR 3.3.5.2	Perform CHANNEL CALIBRATION.	6 months
SR 3.3.5.3	Perform CHANNEL CALIBRATION.	18 months

Table 3.3.5-1 (page 1 of 1)
LOP DG Start Instrumentation

		FUNCTION	REQUIRED CHANNELS PER BUS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT	ALLOWABLE VALUE
1.		6.9 kV Emergency Bus Undervoltage (Loss of Voltage)				
	a.	Bus Undervoltage	3	SR 3.3.5.1 SR 3.3.5.2	≥ 5994 V and ≤ 6006 V	≥ 5967.6 V
	b.	Time Delay	2	SR 3.3.5.3	≥ 0.73 sec and ≤ 0.77 sec	≥ 0.58 sec and ≤ 0.94 sec
2.		6.9 kV Emergency Bus Undervoltage (Degraded Voltage)				
	a.	Bus Undervoltage	3	SR 3.3.5.1 SR 3.3.5.2	≥ 6593.4 V and ≤ 6606.6 V	≥ 6570 V
	b.	Time Delay	2	SR 3.3.5.3	≥ 9.73 sec and ≤ 10.27 sec	≥ 9.42 sec and ≤ 10.49 sec
3.		Diesel Generator Start	2	SR 3.3.5.1 SR 3.3.5.2	≥ 4733.4 V and ≤ 4926.6 V with an internal time delay of ≥ 0.46 sec and ≤ 0.54 sec	≥ 2295.6 V with an internal time delay of 0.56 sec at zero volts
4.		Load Shed	4	SR 3.3.5.1 SR 3.3.5.2	≥ 4733.4 V and ≤ 4926.6 V with an internal time delay of ≥ 2.79 sec and ≤ 3.21 sec	≥ 2295.6 V with an internal time delay of ≤ 3.3 sec at zero volts.

3.3 INSTRUMENTATION

3.3.6 Containment Vent Isolation Instrumentation

LCO 3.3.6 The Containment Vent Isolation instrumentation for each Function in Table 3.3.6-1 shall be OPERABLE.

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

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One radiation monitoring channel inoperable.	A.1 Restore the affected channel to OPERABLE status.	4 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more Functions with one or more manual or automatic actuation trains inoperable. <u>OR</u> Two radiation monitoring channels inoperable. <u>OR</u> Required Action and associated Completion Time of Condition A not met.	----------NOTE---------- One train of automatic actuation logic may be bypassed and Required Action B.1 may be delayed for up to 4 hours for Surveillance testing provided the other train is OPERABLE. ---------- B.1 Enter applicable Conditions and Required Actions of LCO 3.6.3, "Containment Isolation Valves," for containment purge and exhaust isolation valves made inoperable by isolation instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.6-1 to determine which SRs apply for each Containment Vent Isolation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.6.2	----------NOTE---------- This surveillance is only applicable to the actuation logic of the ESFAS instrumentation. ---------- Perform ACTUATION LOGIC TEST.	92 days on a STAGGERED TEST BASIS
SR 3.3.6.3	----------NOTE---------- This surveillance is only applicable to the master relays of the ESFAS instrumentation. ---------- Perform MASTER RELAY TEST.	92 days on a STAGGERED TEST BASIS
SR 3.3.6.4	Perform COT.	92 days
SR 3.3.6.5	Perform SLAVE RELAY TEST.	92 days <u>OR</u> 18 months for Westinghouse type AR and Potter & Brumfield MDR Series relays

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.6	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	18 months
SR 3.3.6.7	Perform CHANNEL CALIBRATION.	18 months

Table 3.3.6-1 (page 1 of 1)
Containment Vent Isolation Instrumentation

FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Manual Initiation	2	SR 3.3.6.6	NA
2. Automatic Actuation Logic and Actuation Relays	2 trains	SR 3.3.6.2 SR 3.3.6.3 SR 3.3.6.5	NA
3. Containment Purge Exhaust Radiation Monitors	2	SR 3.3.6.1 SR 3.3.6.4 SR 3.3.6.7	≤ 2.8E-02 μCi/cc (1.14×10^4 cpm)
4. Safety Injection	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 1, for all initiation functions and requirements.		

3.3 INSTRUMENTATION

3.3.7 Control Room Emergency Ventilation System (CREVS) Actuation Instrumentation

LCO 3.3.7 The CREVS actuation instrumentation for each Function in Table 3.3.7-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, 4, 5, and 6
During movement of irradiated fuel assemblies.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel or train inoperable.	A.1 Place one CREVS train in emergency radiation protection mode.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One or more Functions with two channels or two trains inoperable.	B.1.1	Place one CREVS train in emergency radiation protection mode.	Immediately
	AND		
	B.1.2	Enter applicable Conditions and Required Actions for one CREVS train made inoperable by inoperable CREVS actuation instrumentation	Immediately
	OR		
	B.2	Place both trains in emergency radiation protection mode.	Immediately
C. Required Action and associated Completion Time for Condition A or B not met in MODE 1, 2, 3, or 4.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 5	36 hours
D. Required Action and associated Completion Time for Condition A or B not met during movement of irradiated fuel assemblies.	D.1	Suspend movement of irradiated fuel assemblies.	Immediately
E. Required Action and associated Completion Time for Condition A or B not met in MODE 5 or 6.	E.1	Initiate action to restore one CREVS train to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.7-1 to determine which SRs apply for each CREVS Actuation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.7.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.7.2	Perform COT.	92 days
SR 3.3.7.3	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	18 months
SR 3.3.7.4	Perform CHANNEL CALIBRATION.	18 months

Table 3.3.7-1 (page 1 of 1)
CREVS Actuation Instrumentation

FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Manual Initiation	2 trains	SR 3.3.7.3	NA
2. Control Room Radiation Control Room Air Intakes	2	SR 3.3.7.1 SR 3.3.7.2 SR 3.3.7.4	≤ 1.647E-04 μC/cc (3,308 cpm)
3. Safety Injection	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 1, for all initiation functions and requirements.		

3.3 INSTRUMENTATION

3.3.8 Auxiliary Building Gas Treatment System (ABGTS) Actuation Instrumentation

LCO 3.3.8 The ABGTS actuation instrumentation for each Function in Table 3.3.8-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.8-1.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more Functions with one channel or train inoperable.	A.1	Place one ABGTS train in operation.	7 days
B. One or more Functions with two channels or two trains inoperable.	B.1.1	Place one ABGTS train in operation.	Immediately
	AND		
	B.1.2	Enter applicable Conditions and Required Actions of LCO 3.7.12, "Auxiliary Building Gas Treatment System (ABGTS)," for one train made inoperable by inoperable actuation instrumentation	Immediately
	OR		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	Place both trains in emergency radiation protection mode.	Immediately
C. Required Action and associated Completion Time for Condition A or B not met.	C.1	Be in MODE 3.	hours
	AND		
	C.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.1	----------NOTE---------- Verification of setpoint is not required. ---------- Perform TADOT.	18 months

Table 3.3.8-1 (page 1 of 1)
ABGTS Actuation Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1.	Manual Initiation	1,2,3,4	2	SR 3.3.8.1	NA
2.	Containment Isolation	Refer to LCO 3.3.2, Function 3.a., for all Phase A initiating functions and requirements.			

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the limits specified below:

a. Pressurizer pressure ≥ 2214 psig;

b. RCS average temperature ≤ 593.2°F; and

c. RCS total flow rate ≥ 380,000 gpm (process computer or control board indication).

APPLICABILITY: MODE 1.

----------NOTE----------
Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1	Restore RCS DNB parameter(s) to within limit.	2 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is ≥ 2214 psig.	12 hours
SR 3.4.1.2	Verify RCS average temperature is ≤ 593.2°F.	12 hours
SR 3.4.1.3	Verify RCS total flow rate is ≥ 380,000 gpm (process computer or control board indication).	12 hours
SR 3.4.1.4	----------NOTE---------- Required to be performed within 24 hours after ≥ 90% RTP. ---------- Verify by precision heat balance method that RCS total flow rate is ≥ 380,000 gpm.	18 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 RCS Minimum Temperature for Criticality

LCO 3.4.2 Each RCS loop average temperature (T_{avg}) shall be ≥ 551°F.

APPLICABILITY: MODE 1,
MODE 2 with k_{eff} ≥ 1.0.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. T_{avg} in one or more RCS loops not within limit.	A.1 Be in MODE 3.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.2.1	Verify RCS T_{avg} in each loop ≥ 551°F.	----------NOTE--------- Only required if T_{avg} - T_{ref} deviation alarm not reset and any RCS loop T_{avg} < 561°F. ---------- 30 minutes

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.3 RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. ----------NOTE---------- Required Action A.2 shall be completed whenever this Condition is entered. ---------- Requirements of LCO not met in MODE 1, 2, 3, or 4.	A.1 AND A.2	Restore parameter(s) to within limits Determine RCS is acceptable for continued operation.	30 minutes 72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 AND B.2	Be in MODE 3. Be in MODE 5 with RCS pressure < 500 psig	6 hours 36 hours
C. ----------NOTE---------- Required Action C.2 shall be completed whenever this Condition is entered. ---------- Requirements of LCO not met any time in other than MODE 1, 2, 3, or 4.	C.1 AND C.2	Initiate action to restore parameter(s) to within limits. Determine RCS is acceptable for continued operation.	Immediately Prior to entering MODE 4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	----------NOTE---------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. ---------- Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	30 minutes

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Loops - MODES 1 and 2

LCO 3.4.4 Four RCS loops shall be OPERABLE and in operation.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of LCO not met.	A.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.4.1 Verify each RCS loop is in operation.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 RCS Loops - MODE 3

LCO 3.4.5 Two RCS loops shall be OPERABLE, and either:

a. Two RCS loops shall be in operation when the Rod Control System is capable of rod withdrawal; or

b. One RCS loop shall be in operation when the Rod Control System is not capable of rod withdrawal.

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

All reactor coolant pumps may be de-energized for ≤ 1 hour per 8 hour period provided:

a. No operations are permitted that would cause reduction of the RCS boron concentration; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature.

APPLICABILITY: MODE 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required RCS loop inoperable.	A.1	Restore required RCS loop to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 4.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One required RCS loop not in operation, and reactor trip breakers closed and Rod Control System capable of rod withdrawal.	C.1	Restore required RCS loop to operation.	1 hour
	OR		
	C.2	De-energize all control rod drive mechanisms (CRDMs).	1 hour
D. All RCS loops inoperable.	D.1	De-energize all CRDMs.	Immediately
OR	AND		
No RCS loop in operation.	D.2	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND		
	D.3	Initiate action to restore one RCS loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify required RCS loops are in operation	12 hours
SR 3.4.5.2	Verify steam generator secondary side water levels are ≥ 6% narrow range for required RCS loops.	12 hours
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 RCS Loops - MODE 4

LCO 3.4.6 Two loops shall be OPERABLE, and consist of either:

a. Any combination of RCS loops and residual heat removal (RHR) loops, and one loop shall be in operation, when the rod control system is not capable of rod withdrawal; or

b. Two RCS loops, and both loops shall be in operation, when the rod control system is capable of rod withdrawal.

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

1. No RCP shall be started with any RCS cold leg temperature ≤ 350ºF unless the secondary side water temperature of each steam generator (SG) is ≤ 50°F above each of the RCS cold leg temperatures.

2. For the initial 7 hours after entry into MODE 3 from MODE 1 or MODE 2, two loops shall consist of:

   a. Two RCS loops with one loop in operation when the rod control system is not capable of rod withdrawal; or

   b. Two RCS loops with both loops in operation when the rod control system is capable of rod withdrawal.

3. Average reactor coolant temperature shall be maintained > 200ºF for the initial 7 hours after entry into MODE 3 from MODE 1 or MODE 2.

APPLICABILITY: MODE 4.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Only one RCS loop OPERABLE. AND Two RHR loops inoperable. OR Less than 7 hours since entry into MODE 3 from MODE 1 or MODE 2.	A.1	Initiate action to restore a second required RCS or RHR loop to OPERABLE status.	Immediately
B. One required RHR loop inoperable. AND No RCS loops OPERABLE.	B.1	Be in MODE 5.	24 hours
C. One required RCS loop not in operation, and reactor trip breakers closed and Rod Control System capable of rod withdrawal.	C.1	Restore required RCS loop to operation.	1 hour
	OR		
	C.2	De-energize all control rod drive mechanisms (CRDMs).	1 hour
D. Required RCS or RHR loops inoperable. OR No required RCS or RHR loop in operation	D.1	De-energize all CRDMs.	Immediately
	AND		
	D.2	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND		
	D.3	Initiate action to restore one required loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify two RCS loops are in operation when the rod control system is capable of rod withdrawal.	12 hours
SR 3.4.6.2	Verify one required RHR or RCS loop is in operation when the rod control system is not capable of rod withdrawal.	12 hours
SR 3.4.6.3	Verify SG secondary side water levels are greater than or equal to 32% narrow range for required RCS loops.	12 hours
SR 3.4.6.4	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops - MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side water level of at least two steam generators (SGs) shall be greater than or equal to 6% narrow range.

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

1. One required RHR loop may be inoperable for up to 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

2. No reactor coolant pump shall be started with one or more RCS cold leg temperatures less than or equal to the COMS arming temperature specified in the PTLR unless the secondary side water temperature of each SG is ≤ 50°F above each of the RCS cold leg temperatures.

3. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

APPLICABILITY: MODE 5 with RCS loops filled.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR loop inoperable. <u>AND</u> Required SGs secondary side water levels not within limits.	A.1	Initiate action to restore a second RHR loop to OPERABLE status.	Immediately
	<u>OR</u>		
	A.2	Initiate action to restore required SG secondary side water levels to within limits.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Required RHR loops inoperable. <u>OR</u> No RHR loop in operation.	B.1	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	<u>AND</u>		
	B.2	Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.7.2	Verify SG secondary side water level is greater than or equal to 6% narrow range in required SGs.	12 hours
SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 RCS Loops - MODE 5, Loops Not Filled

LCO 3.4.8 Two residual heat removal (RHR) loops shall be OPERABLE and one RHR loop shall be in operation.

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

1. All RHR pumps may be de-energized for ≤ 15 minutes when switching from one loop to another provided:

   a. The core outlet temperature is maintained > 10°F below saturation temperature.

   b. No operations are permitted that would cause a reduction of the RCS boron concentration; and

   c. No draining operations to further reduce the RCS water volume are permitted.

2. One RHR loop may be inoperable for ≤ 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

APPLICABILITY: MODE 5 with RCS loops not filled.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR loop inoperable.	A.1 Initiate action to restore RHR loop to OPERABLE status.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Required RHR loops inoperable. <u>OR</u> No RHR loop in operation.	B.1	Suspend all operations involving reduction in RCS boron concentration.	Immediately
	<u>AND</u>		
	B.2	Initiate action to restore one RHR loop to OPERABLE status and operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.8.2	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE with:

a. Pressurizer water level ≤ 92%; and

b. Two groups of pressurizer heaters OPERABLE with the capacity of each group ≥ 150 kW

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Pressurizer water level not within limit.	A.1	Be in MODE 3 with reactor trip breakers open.	6 hours
	AND		
	A.2	Be in MODE 4.	12 hours
B. One required group of pressurizer heaters inoperable.	B.1	Restore required group of pressurizer heaters to OPERABLE status.	72 hours
C. Required Action and associated Completion Time of Condition B not met.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify pressurizer water level is ≤ 92%.	12 hours
SR 3.4.9.2	Verify capacity of each required group of pressurizer heaters is ≥ 150 kW.	92 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Pressurizer Safety Valves

LCO 3.4.10 Three pressurizer safety valves shall be OPERABLE with lift settings ≥ 2410 psig and ≤ 2560 psig.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with all RCS cold leg temperatures greater than the COMS arming temperature specified in the PTLR.

----------NOTE----------
The lift settings are not required to be within the LCO limits during MODE 3 and MODE 4 with all RCS cold leg temperatures greater than the COMS arming temperature specified in the PTLR for the purpose of setting the pressurizer safety valves under ambient (hot) conditions. This exception is allowed for 54 hours following entry into MODE 3 provided a preliminary cold setting was made prior to heatup.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1	Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. <u>OR</u> Two or more pressurizer safety valves inoperable.	B.1 <u>AND</u> B.2	Be in MODE 3. Be in MODE 4 with any RCS cold leg temperature less than or equal to the COMS arming temperature specified in the PTLR.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	Verify each pressurizer safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1% of the nominal lift setting of 2485 psig.	In accordance with the Inservice Testing Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

LCO 3.4.11 Each PORV and associated block valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more PORVs inoperable and capable of being manually cycled.	A.1	Close and maintain power to associated block valve.	1 hour
B. One PORV inoperable and not capable of being manually cycled.	B.1	Close associated block valve.	1 hour
	AND		
	B.2	Remove power from associated block valve.	1 hour
	AND		
	B.3	Restore PORV to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One block valve inoperable.	C.1	Place associated PORV in manual control.	1 hour
	AND		
	C.2	Restore block valve 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.	6 hours
	AND		
	D.2	Be in MODE 4.	12 hours
E. Two PORVs inoperable and not capable of being manually cycled.	E.1	Close associated block valves.	1 hour
	AND		
	E.2	Remove power from associated block valves.	1 hour
	AND		
	E.3	Be in MODE 3.	6 hours
	AND		
	E.4	Be in MODE 4.	12 hours
F. Two block valves inoperable.	F.1	Place associated PORVs in manual control.	1 hour
	AND		
	F.2	Restore one block valve to OPERABLE status.	2 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Required Action and associated Completion Time of Condition F not met.	G.1 Be in MODE 3. AND G.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	----------NOTE---------- Not required to be met with block valve closed in accordance with the Required Action of Condition B or E. ---------- Perform a complete cycle of each block valve.	 92 days
SR 3.4.11.2	Perform a complete cycle of each PORV.	18 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 Cold Overpressure Mitigation System (COMS)

LCO 3.4.12 A COMS System shall be OPERABLE with a maximum of one charging pump and no safety injection pump capable of injecting into the RCS and the accumulators isolated and either a or b below.

a. Two RCS relief valves, as follows:

   1. Two power operated relief valves (PORVs) with lift settings within the limits specified in the PTLR, or

   2. One PORV with a lift setting within the limits specified in the PTLR and the RHR suction relief valve with a setpoint ≥ 436.5 psig and ≤ 463.5 psig.

b. The RCS depressurized and an RCS vent capable of relieving > 475 gpm water flow.

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

1. Two charging pumps may be made capable of injecting for less than or equal to one hour for pump swap operations.

2. Accumulator may be unisolated when accumulator pressure is less than the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.

APPLICABILITY: MODE 4 with any RCS cold leg temperature ≤ to the COMS arming temperature specified in the PTLR,
MODE 5,
MODE 6 when the reactor vessel head is on.

ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable when entering MODE 4.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more safety injection pumps capable of injecting into the RCS.	A.1	Initiate action to verify no safety injection pumps are capable of injecting into the RCS.	Immediately
B. Two or more charging pumps capable of injecting into the RCS.	B.1	Initiate action to verify a maximum of one charging pump is capable of injecting into the RCS.	Immediately
C. An accumulator not isolated when the accumulator pressure is greater than or equal to the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	C.1	Isolate affected accumulator.	1 hour
D. Required Action and associated Completion Time of Condition C not met.	D.1	Increase RCS cold leg temperature to greater than the COMS arming temperature specified in the PTLR.	12 hours
	OR		
	D.2	Depressurize affected accumulator to less than the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. One required RCS relief valve inoperable in MODE 4 with any RCS cold leg temperature less than or equal to the COMS arming temperature specified in the PTLR.	E.1	Restore required RCS relief valve to OPERABLE status.	7 days
F. One required RCS relief valve inoperable in MODE 5 or 6.	F.1	Restore required RCS relief valve to OPERABLE status.	24 hours
G. Two required RCS relief valves inoperable. <u>OR</u> Required Action and associated Completion Time of Condition A, B, D, E, or F not met. <u>OR</u> COMS inoperable for any reason other than Condition A, B, C, D, E, or F.	G.1	Depressurize RCS and establish RCS vent.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.12.1	Verify no safety injection pumps are capable of injecting into the RCS.	Within 4 hours after entering MODE 4 from MODE 3 prior to the temperature of one or more RCS cold legs decreasing below the COMS arming temperature specified in the PTLR. AND 12 hours thereafter
SR 3.4.12.2	Verify a maximum of one charging pump is capable of injecting into the RCS.	Within 4 hours after entering MODE 4 from MODE 3 prior to the temperature of one or more RCS cold legs decreasing below the COMS arming temperature specified in the PTLR. AND 12 hours thereafter
SR 3.4.12.3	Verify each accumulator is isolated.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.4	----------NOTE---------- Only required to be performed when complying with LCO 3.4.12.b. ---------- Verify RCS vent open.	12 hours for unlocked open vent paths <u>AND</u> 31 days for locked open vent paths
SR 3.4.12.5	Verify PORV block valve is open for each required PORV.	72 hours
SR 3.4.12.6	Verify both RHR suction isolation valves are locked open with operator power removed for the required RHR suction relief valve.	31 days
SR 3.4.12.7	----------NOTE---------- Required to be met within 12 hours after decreasing RCS cold leg temperature to less than or equal to the COMS arming temperature specified in the PTLR. ---------- Perform a COT on each required PORV, excluding actuation.	31 days
SR 3.4.12.8	Perform CHANNEL CALIBRATION for each required PORV actuation channel.	18 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE; and

d. 150 gallons per day primary-to-secondary LEAKAGE through any one steam generator (SG).

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS operational LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE or primary-to-secondary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. OR Pressure boundary LEAKAGE exists. OR Primary-to-secondary LEAKAGE not within limit.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	----------NOTES---------- 1. Not required to be performed until 12 hours after establishment of steady state operation. 2. Not applicable to primary-to-secondary LEAKAGE. ---------- Verify RCS operational LEAKAGE is within limits by performance of RCS water inventory balance.	72 hours
SR 3.4.13.2	----------NOTE---------- Not required to be performed until 12 hours after establishment of steady state operation. ---------- Verify primary-to-secondary LEAKAGE is less than or equal to 150 gallons per day through any one SG.	72 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

LCO 3.4.14 Leakage from each RCS PIV shall be within limit.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4, except valves in the residual heat removal (RHR) flow path when in, or during the transition to or from, the RHR 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 an inoperable PIV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more flow paths with leakage from one or more RCS PIVs not within limit.	----------NOTE---------- Each valve used to satisfy Required Action A.1 must have been verified to meet SR 3.4.14.1 and be in the reactor coolant pressure boundary. ----------	
	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
	<u>AND</u>	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	Restore RCS PIV to within limits.	72 hours
B. Required Action and associated Completion Time for Condition A not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.14.1	----------NOTE---------- 1. Not required to be performed in MODES 3 and 4. 2. Not required to be performed on the RCS PIVs located in the RHR flow path when in the shutdown cooling mode of operation. 3. RCS PIVs actuated during the performance of this Surveillance are not required to be tested more than once if a repetitive testing loop cannot be avoided. ---------- Verify leakage from each RCS PIV is equivalent to ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at an RCS pressure ≥ 2215 psig and ≤ 2255 psig.	In accordance with the Inservice Testing Program, and 18 months AND Prior to entering MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 9 months AND Within 24 hours following valve actuation due to automatic or manual action or flow through the valve

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.15 RCS Leakage Detection Instrumentation

LCO 3.4.15 The following RCS leakage detection instrumentation shall be OPERABLE:

1. One containment pocket sump level monitor; and
2. One lower containment atmosphere particulate radioactivity monitor.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Required containment pocket sump level monitor inoperable.	A.1	Perform SR 3.4.13.1.	Once per 24 hours
	AND		
	A.2	Restore required containment pocket sump level monitor to OPERABLE status.	30 days
B. Required containment atmosphere particulate radioactivity monitor inoperable.	B.1.1	Analyze grab samples of the containment atmosphere.	Once per 24 hours
	OR		
	B.1.2	Perform SR 3.4.13.1.	Once per 24 hours
	AND		
	B.2	Restore required containment atmosphere particulate radioactivity monitor to OPERABLE status.	30 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours
D. All required monitors inoperable.	D.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.15.1	Perform CHANNEL CHECK of the required containment atmosphere particulate radioactivity monitor.	12 hours
SR 3.4.15.2	Perform COT of the required containment atmosphere particulate radioactivity monitor.	92 days
SR 3.4.15.3	Perform CHANNEL CALIBRATION of the required containment pocket sump level monitor.	18 months
SR 3.4.15.4	Perform CHANNEL CALIBRATION of the required containment atmosphere particulate radioactivity monitor.	18 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 RCS Specific Activity

LCO 3.4.16 The specific activity of the reactor coolant shall be within limits.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS average temperature (T_{avg}) ≥ 500°F.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. DOSE EQUIVALENT I-131 > 0.265 μCi/gm.	----------NOTE---------- LCO 3.0.4.c is applicable. ----------		
	A.1	Verify DOSE EQUIVALENT I-131 ≤ 14 μCi/gm.	Once per 4 hours
	AND		
	A.2	Restore DOSE EQUIVALENT I-131 to within limit.	48 hours
B. Gross specific activity of the reactor coolant not within limit.	B.1	Perform SR 3.4.16.2.	4 hours
	AND		
	B.2	Be in MODE 3 with T_{avg} < 500°F.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A not met. OR DOSE EQUIVALENT I-131 > 14 μCi/gm.	C.1 Be in MODE 3 with T_{avg} < 500°F.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	Verify reactor coolant gross specific activity ≤ 100/ $\bar{E}$ μCi/gm.	7 days
SR 3.4.16.2	----------NOTE---------- Only required to be performed in MODE 1. ---------- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity ≤ 0.265 μCi/gm.	14 days AND Between 2 hours and 6 hours after a THERMAL POWER change of ≥ 15% RTP within a 1 hour period

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.16.3	----------NOTE---------- Required to be performed within 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for ≥ 48 hours. ---------- Determine $\bar{E}$ from a sample taken in MODE 1 after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for ≥ 48 hours.	184 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Steam Generator (SG) Tube Integrity

LCO 3.4.17 SG tube integrity shall be maintained

AND

All SG tubes satisfying the tube plugging criteria shall be plugged in accordance with the Steam Generator Program.

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

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each SG tube.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more SG tubes satisfying the tube plugging criteria and not plugged in accordance with the Steam Generator Program.	A.1	Verify tube integrity of the affected tube(s) is maintained until the next refueling outage or SG tube inspection.	7 days
	AND		
	A.2	Plug the affected tube(s) in accordance with the Steam Generator Program.	Prior to entering MODE 4 following the next refueling outage or SG tube inspection.
B. Required Action and associated Completion Time of Condition A not met. OR SG tube integrity not maintained.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.17.1	Verify steam generator tube integrity in accordance with the Steam Generator Program.	In accordance with the Steam Generator Program.
SR 3.4.17.2	Verify that each inspected SG tube that satisfies the tube plugging criteria is plugged in accordance with the Steam Generator Program.	Prior to entering MODE 4 following a SG tube inspection.

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.1 Accumulators

LCO 3.5.1 Four ECCS accumulators shall be OPERABLE.

APPLICABILITY: MODES 1 and 2,
MODE 3 with pressurizer pressure > 1000 psig.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One accumulator inoperable due to boron concentration not within limits.	A.1	Restore boron concentration to within limits.	72 hours
B. One accumulator inoperable for reasons other than Condition A.	B.1	Restore accumulator to OPERABLE status.	24 hours
C. Required Action and associated Completion Time of Condition A or B not met.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Reduce pressurizer pressure to ≤ 1000 psig.	12 hours
D. Two or more accumulators inoperable.	D.3	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify each accumulator isolation valve is fully open.	12 hours
SR 3.5.1.2	Verify borated water volume in each accumulator is ≥ 7630 gallons and ≤ 8000 gallons.	12 hours
SR 3.5.1.3	Verify nitrogen cover pressure in each accumulator is ≥ 610 psig and ≤ 660 psig.	12 hours
SR 3.5.1.4	Verify boron concentration in each accumulator is ≥ 3000 ppm and ≤ 3300 ppm.	31 days AND ----------NOTE--------- Only required to be performed for affected accumulators ---------- Once within 6 hours after each solution volume increase of ≥ 75 gallons, that is not the result of addition from the refueling water storage tank
SR 3.5.1.5	Verify power is removed from each accumulator isolation valve operator when pressurizer pressure is ≥ 1000 psig.	31 days

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 ECCS - Operating

LCO 3.5.2 Two ECCS trains shall be OPERABLE.

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

1. In MODE 3, both safety injection (SI) pump flow paths may be isolated by closing the isolation valves for up to 2 hours to perform pressure isolation valve testing per SR 3.4.14.1.

2. In MODE 3, the safety injection pumps and charging pumps may be made incapable of injecting to support transition into or from the Applicability of the LCO 3.4.12, Cold Overpressure Mitigation System (COMS) for up to four hours or until the temperature of all the RCS cold legs exceeds the COMS arming temperature specified in the PTLR, whichever occurs first.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more trains inoperable. <u>AND</u> At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available.	A.1 Restore train(s) to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify the following valves are in the listed position with power to the valve operator removed. Number / Position / Function 2-FCV-63-1 / Open / RHR Supply 2-FCV-63-22 / Open / SIS Discharge	12 hours
SR 3.5.2.2	Verify each ECCS manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.5.2.3	Verify ECCS piping is full of water.	31 days
SR 3.5.2.4	Verify each ECCS pump's developed head at the test flow point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.5.2.5	Verify each ECCS automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	18 months
SR 3.5.2.6	Verify each ECCS pump starts automatically on an actual or simulated actuation signal.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.7	Verify, for each ECCS throttle valve listed below, each position stop is in the correct position. Valve Number CCP Discharge Throttle Valves: 2-63-582, 2-63-583, 2-63-584, 2-63-585 SI Cold Leg Throttle Valves: 2-63-550, 2-63-552, 2-63-554, 2-63-556 SI Hot Leg Throttle Valves: 2-63-542, 2-63-544, 2-63-546, 2-63-548	18 months
SR 3.5.2.8	Verify, by visual inspection, each ECCS train containment sump suction inlet is not restricted by debris and the suction inlet trash racks and screens show no evidence of structural distress or abnormal corrosion.	18 months

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.3 ECCS - Shutdown

LCO 3.5.3 One ECCS train shall be OPERABLE.

APPLICABILITY: MODE 4.

ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable to ECCS high head (centrifugal charging) subsystem.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required ECCS residual heat removal (RHR) subsystem inoperable.	----------NOTE---------- The required ECCS residual heat removal (RHR) subsystem may be inoperable for up to 1 hour for surveillance testing of valves provided that alternate heat removal methods are available via the steam generators to maintain the Reactor Coolant System T_{avg} less than 350°F and provided that the required subsystem is capable of being manually realigned to the ECCS mode of operation from the main control room. ---------- A.1 Initiate action to restore required ECCS RHR subsystem to OPERABLE status	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Required ECCS centrifugal charging subsystem inoperable.	B.1	Restore required ECCS centrifugal charging subsystem to OPERABLE status.	1 hour
C. Required Action and associated Completion Time of Condition B not met.	C.1	Be in MODE 5.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	----------NOTE---------- An RHR train may be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned to the ECCS mode of operation. ---------- The following SRs are applicable for all equipment required to be OPERABLE: SR 3.5.2.1 SR 3.5.2.3 SR 3.5.2.4 SR 3.5.2.7 SR 3.5.2.8	In accordance with applicable SRs

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.4 Refueling Water Storage Tank (RWST)

LCO 3.5.4 The RWST shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. RWST boron concentration not within limits. <u>OR</u> RWST borated water temperature not within limits.	A.1	Restore RWST to OPERABLE status.	8 hours
B. RWST inoperable for reasons other than Condition A.	B.1	Restore RWST to OPERABLE status.	1 hour
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	C.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.4.1	----------NOTE---------- Only required to be performed when ambient air temperature is < 60 °F or > 105 °F. ---------- Verify RWST borated water temperature is ≥ 60 °F and ≤ 105 °F.	24 hours
SR 3.5.4.2	Verify RWST borated water volume is ≥ 370,000 gallons.	7 days
SR 3.5.4.3	Verify boron concentration in the RWST is ≥ 3100 ppm and ≤ 3300 ppm.	7 days

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.5 Seal Injection Flow

LCO 3.5.5 Reactor coolant pump seal injection flow shall be ≤ 40 gpm with charging pump discharge header pressure ≥ 2430 psig and the pressurizer level control valve full open.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Seal injection flow not within limit.	A.1	Adjust manual seal injection throttle valves to give a flow within limit with charging pump discharge header pressure ≥ 2430 psig and the pressurizer level control valve full open.	4 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.5.1	----------NOTE---------- Required to be performed within 4 hours after the Reactor Coolant System pressure stabilizes at ≥ 2215 psig and ≤ 2255 psig. ---------- Verify manual seal injection throttle valves are adjusted to give a flow within limit with charging pump discharge header pressure ≥ 2430 psig and the pressurizer level control valve full open.	31 days

3.6 CONTAINMENT SYSTEMS

3.6.1 Containment

LCO 3.6.1 Containment shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Containment inoperable.	A.1	Restore containment to OPERABLE status	1 hour
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1	Perform required visual examinations and leakage rate testing except for containment air lock testing, in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program.

3.6 CONTAINMENT SYSTEMS

3.6.2 Containment Air Locks

LCO 3.6.2 Two containment air locks shall be OPERABLE.

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

ACTIONS

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

1. Entry and exit is permissible to perform repairs on the affected air lock components.
2. Separate Condition entry is allowed for each air lock.
3. Enter applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when air lock leakage results in exceeding the overall containment leakage rate.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment air locks with one containment air lock door inoperable.	----------NOTES---------- 1. Required Actions A.1, A.2, and A.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit is permissible for 7 days under administrative controls if both air locks are inoperable. ----------	(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.1	Verify the OPERABLE door is closed in the affected air lock.	1 hour
	AND		
	A.2	Lock the OPERABLE door closed in the affected air lock.	24 hours
	AND		
	A.3	----------NOTE---------- Air lock doors in high radiation areas may be verified locked closed by administrative means. ---------- Verify the OPERABLE door is locked closed in the affected air lock.	Once per 31 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more containment air locks with containment air lock interlock mechanism inoperable.	----------NOTES---------- 1. Required Actions B.1, B.2, and B.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit of containment is permissible under the control of a dedicated individual. ----------	
	B.1 Verify an OPERABLE door is closed in the affected air lock.	1 hour
	AND	
	B.2 Lock an OPERABLE door closed in the affected air lock.	24 hours
	AND	
	B.3 ----------NOTE---------- Air lock doors in high radiation areas may be verified locked closed by administrative means. ---------- Verify an OPERABLE door is locked closed in the affected air lock.	Once per 31 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more containment air locks inoperable for reasons other than Condition A or B.	C.1	Initiate action to evaluate overall containment leakage rate per LCO 3.6.1.	Immediately
	AND		
	C.2	Verify a door is closed in the affected air lock.	1 hour
	AND		
	C.3	Restore air lock to OPERABLE status.	24 hours
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1	----------NOTES---------- 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1. ---------- Perform required air lock leakage rate testing in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program
SR 3.6.2.2	----------NOTE---------- Only required to be performed upon entry or exit through the containment air lock. ---------- Verify only one door in the air lock can be opened at a time.	184 days

3.6 CONTAINMENT SYSTEMS

3.6.3 Containment Isolation Valves

LCO 3.6.3 Each containment isolation valve shall be OPERABLE.

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

ACTIONS

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

1. Penetration flow path(s) may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each penetration flow path.
3. Enter applicable Conditions and Required Actions for systems made inoperable by containment isolation valves.
4. Enter applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when isolation valve leakage results in exceeding the overall containment leakage rate acceptance criteria.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ----------NOTE---------- Only applicable to penetration flow paths with two containment isolation valves. ---------- One or more penetration flow paths with one containment isolation valve inoperable except for purge valve or shield building bypass leakage not within limit.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. <u>AND</u>	4 hours (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 ----------NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ---------- Verify the affected penetration flow path is isolated.	 Once per 31 days for isolation devices outside containment <u>AND</u> Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. ----------NOTE---------- Only applicable to penetration flow paths with two containment isolation valves. ---------- One or more penetration flow paths with two containment isolation valves inoperable except for purge valve or shield building bypass leakage not within limit.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour
C. ----------NOTE---------- Only applicable to penetration flow paths with only one containment isolation valve and a closed system. ---------- One or more penetration flow paths with one containment isolation valve inoperable.	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND C.2 ----------NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ----------	4 hours (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	Verify the affected penetration flow path is isolated.	Once per 31 days
D. Shield building bypass leakage not within limit.	D.1 Restore leakage within limit.	4 hours
E. One or more penetration flow paths with one or more containment purge valves not within purge valve leakage limits.	E.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange. AND	24 hours (continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. (continued)	E.2	----------NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ---------- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside containment <u>AND</u> Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment
	<u>AND</u>		
	E.3	Perform SR 3.6.3.5 for the resilient seal purge valves closed to comply with Required Action E.1.	Once per 92 days
F. Required Action and associated Completion Time not met.	F.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	F.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1	Verify each containment purge valve is closed, except when the containment purge valves are open for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open.	31 days
SR 3.6.3.2	----------NOTE---------- Valves and blind flanges in high radiation areas may be verified by use of administrative controls. ---------- Verify each containment isolation manual valve and blind flange that is located outside containment, the containment annulus, and the Main Steam Valve Vault Rooms, and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	31 days
SR 3.6.3.3	----------NOTE---------- Valves and blind flanges in high radiation areas may be verified by use of administrative controls. ---------- Verify each containment isolation manual valve and blind flange that is located inside containment, the containment annulus, and the Main Steam Valve Vault Rooms, and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days
SR 3.6.3.4	Verify the isolation time of each power operated and each automatic containment isolation valve is within limits.	In accordance with the Inservice Testing Program or 92 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.3.5	Perform leakage rate testing for containment purge valves with resilient seals.	184 days AND Within 92 days after opening the valve
SR 3.6.3.6	Verify each automatic containment isolation valve that is not locked, sealed, or otherwise secured in position, actuates to the isolation position on an actual or simulated actuation signal.	18 months
SR 3.6.3.7	Verify each 24 inch containment lower compartment purge supply and exhaust isolation valve is blocked to restrict the valve from opening > 50°.	18 months
SR 3.6.3.8	Verify the combined leakage rate for all shield building bypass leakage paths is $\leq$ 0.25 L_a when pressurized to $\geq$ 15.0 psig.	In accordance with the Containment Leakage Rate Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.4 Containment Pressure

LCO 3.6.4 Containment pressure shall be ≥ -0.1 and ≤ +0.3 psid relative to the annulus.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Containment pressure not within limits.	A.1	Restore containment pressure to within limits.	1 hour
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.4.1	Verify containment pressure is within limits.	12 hours

3.6 CONTAINMENT SYSTEMS

3.6.5 Containment Air Temperature

LCO 3.6.5 Containment average air temperature shall be:

a. ≥ 85 °F and ≤ 110 °F for the containment upper compartment, and

b. ≥ 100 °F and ≤ 120 °F for the containment lower compartment.

----------NOTE----------
The minimum containment average air temperatures in MODES 2, 3, and 4 may be reduced to 60 °F.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Containment average air temperature not within limits.	A.1	Restore containment average air temperature to within limits.	8 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.5.1	Verify containment upper compartment average air temperature is within limits.	24 hours
SR 3.6.5.2	Verify containment lower compartment average air temperature is within limits.	24 hours

3.6 CONTAINMENT SYSTEMS

3.6.6 Containment Spray System

LCO 3.6.6 Two containment spray trains and two residual heat removal (RHR) spray trains shall be OPERABLE.

----------NOTE----------
The RHR spray train is not required in MODE 4.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One containment spray train inoperable.	A.1	Restore containment spray train to OPERABLE status.	72 hours
B. One RHR spray train inoperable.	B.1	Restore RHR spray train to OPERABLE status.	72 hours
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 5.	84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.6.1	Verify each containment spray manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days
SR 3.6.6.2	Verify each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.6.6.3	Verify each automatic containment spray valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	18 months
SR 3.6.6.4	Verify each containment spray pump starts automatically on an actual or simulated actuation signal.	18 months
SR 3.6.6.5	Verify each spray nozzle is unobstructed.	At first refueling AND 10 years
SR 3.6.6.6	Perform SR 3.5.2.2 and SR 3.5.2.4 for the RHR spray system.	In accordance with Applicable SRs

3.6 CONTAINMENT SYSTEMS

3.6.7 RESERVED FOR FUTURE ADDITION

3.6 CONTAINMENT SYSTEMS

3.6.8 Hydrogen Mitigation System (HMS)

LCO 3.6.8 Two HMS trains shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One HMS train inoperable.	A.1	Restore HMS train to OPERABLE status.	7 days
	OR		
	A.2	Perform SR 3.6.8.1 on the OPERABLE train.	Once per 7 days
B. One containment region with no OPERABLE hydrogen igniter.	B.1	Restore one hydrogen igniter in the affected containment region to OPERABLE status.	7 days
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.8.1	Energize each HMS train power supply breaker and verify ≥ 33 igniters are energized in each train.	92 days
SR 3.6.8.2	Verify at least one hydrogen igniter is OPERABLE in each containment region.	92 days
SR 3.6.8.3	Energize each hydrogen igniter and verify temperature is ≥ 1700 °F.	18 months

3.6 CONTAINMENT SYSTEMS

3.6.9 Emergency Gas Treatment System (EGTS)

LCO 3.6.9 Two EGTS trains shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One EGTS train inoperable.	A.1	Restore EGTS train to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.9.1	Operate each EGTS train for ≥ 10 continuous hours with heaters operating.	31 days
SR 3.6.9.2	Perform required EGTS filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.9.3	Verify each EGTS train actuates on an actual or simulated actuation signal.	18 months
SR 3.6.9.4	Verify each EGTS train produces a flow rate ≥ 3600 cfm and ≤ 4400 cfm within 20 seconds from the initiation of a Containment Isolation Phase A signal.	18 months on a STAGGERED TEST BASIS

3.6 CONTAINMENT SYSTEMS

3.6.10 Air Return System (ARS)

LCO 3.6.10 Two ARS trains shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One ARS train inoperable.	A.1	Restore ARS train to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.10.1	Verify each ARS fan starts on an actual or simulated actuation signal, after a delay of ≥ 8.0 minutes and ≤ 10.0 minutes, and operates for ≥ 15 minutes.	92 days
SR 3.6.10.2	Verify, with the ARS fan dampers closed, each ARS fan motor current is ≥ 54 amps and ≤ 94 amps.	92 days
SR 3.6.10.3	Verify, with the ARS fan not operating, each ARS fan damper opens when ≤ 92.4 in-lb is applied.	92 days

3.6 CONTAINMENT SYSTEMS

3.6.11 Ice Bed

LCO 3.6.11 The ice bed shall be OPERABLE

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Ice bed inoperable.	A.1 Restore ice bed to OPERABLE status.	48 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.11.1	Verify maximum ice bed temperature is ≤ 27°F.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.11.2	Verify total weight of stored ice is greater than or equal to 2,750,700 lb by: a. Weighing a representative sample of ≥ 144 ice baskets and verifying each basket contains greater than or equal to 1415 lb of ice; and b. Calculating total weight of stored ice, at a 95 percent confidence level, using all ice basket weights determined in SR 3.6.11.2.a.	18 months
SR 3.6.11.3	Verify azimuthal distribution of ice at a 95 percent confidence level by subdividing weights, as determined by SR 3.6.11.2.a, into the following groups: a. Group 1-bays 1 through 8; b. Group 2-bays 9 through 16; and c. Group 3-bays 17 through 24. The average ice weight of the sample baskets in each group from radial rows 1, 2, 4, 6, 8, and 9 shall be greater than or equal to 1415 lb.	18 months
SR 3.6.11.4	Verify, by visual inspection, accumulation of ice on structural members comprising flow channels through the ice bed is less than or equal to 15 percent blockage of the total flow area for each safety analysis section.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.11.5	----------NOTE---------- The requirements of this SR are satisfied if the boron concentration and pH values obtained from averaging the individual sample results are within the limits specified below. ---------- Verify, by chemical analysis of the stored ice in at least one randomly selected ice basket from each ice condenser bay, that ice bed: a. Boron concentration is ≥ 1800 ppm and ≤2000 ppm; and b. pH is ≥ 9.0 and ≤ 9.5.	54 months
SR 3.6.11.6	Visually inspect, for detrimental structural wear, cracks, corrosion, or other damage, two ice baskets from each azimuthal group of bays.	40 months
SR 3.6.11.7	----------NOTE---------- The chemical analysis may be performed on either the liquid solution or on the resulting ice. ---------- Verify, by chemical analysis, that ice added to the ice condenser meets the boron concentration and pH requirements or SR 3.6.11.5.	Each ice addition

3.6 CONTAINMENT SYSTEMS

3.6.12 Ice Condenser Doors

LCO 3.6.12 The ice condenser inlet doors, intermediate deck doors, and top deck doors shall be OPERABLE and closed.

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

ACTIONS

----------NOTE----------
1. Separate Condition entry is allowed for each ice condenser door.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more ice condenser inlet doors inoperable due to being physically restrained from opening.	A.1	Restore inlet door to OPERABLE status.	1 hour
B. One or more ice condenser doors inoperable for reasons other than Condition A or not closed.	B.1	Verify maximum ice bed temperature is ≤ 27°F.	Once per 4 hours
	AND		
	B.2	Restore ice condenser door to OPERABLE status and closed positions.	14 days
C. Required Action and associated Completion Time of Condition B not met.	C.1	Restore ice condenser door to OPERABLE status and closed positions.	48 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A or C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.12.1	Verify all inlet doors indicate closed by the Inlet Door Position Monitoring System.	12 hours
SR 3.6.12.2	Verify, by visual inspection, each intermediate deck door is closed and not impaired by ice, frost, or debris.	7 days
SR 3.6.12.3	Verify, by visual inspection, each inlet door is not impaired by ice, frost, or debris.	3 months during first year after receipt of license AND 18 months
SR 3.6.12.4	Verify torque required to cause each inlet door to begin to open is ≤ 675 in-lb.	3 months during first year after receipt of license AND 18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.12.5	Perform a torque test on a sampling of ≥ 50% of the inlet doors.	3 months during first year after receipt of license AND 18 months
SR 3.6.12.6	Verify for each intermediate deck door: a. No visual evidence of structural deterioration; b. Free movement of the vent assemblies; and c. Free movement of the door.	3 months during first year after receipt of license AND 18 months
SR 3.6.12.7	Verify, by visual inspection, each top deck door: a. Is in place; b. Free movement of top deck vent assembly; and c. Has no condensation, frost, or ice formed on the door that would restrict its opening.	92 days

3.6 CONTAINMENT SYSTEMS

3.6.13 Divider Barrier Integrity

LCO 3.6.13 Divider barrier integrity shall be maintained.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. ----------NOTE---------- For this action, separate Condition entry is allowed for each personnel access door or equipment hatch. ---------- One or more personnel access doors or equipment hatches between upper and lower containment open or inoperable, other than for personnel transit.	A.1	Restore personnel access doors and equipment hatches to OPERABLE status and closed positions.	1 hour
B. Divider barrier seal inoperable.	B.1	Restore seal to OPERABLE status.	1 hour
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.13.1	Verify, by visual inspection, all personnel access doors and equipment hatches between upper and lower containment compartments are closed.	Prior to entering MODE 4 from MODE 5
SR 3.6.13.2	Verify, by visual inspection, that the seals and sealing surfaces of each personnel access door and equipment hatch have: a. No detrimental misalignments; b. No cracks or defects in the sealing surfaces; and c. No apparent deterioration of the seal material.	Prior to final closure after each opening <u>AND</u> ----------NOTE--------- Only required for seals made of resilient materials ---------- 10 years
SR 3.6.13.3	Verify, by visual inspection, each personnel access door or equipment hatch that has been opened for personnel transit is closed.	After each opening
SR 3.6.13.4	Not used	
SR 3.6.13.5	Visually inspect ≥ 95% of the divider barrier seal length, and verify: a. Seal and seal mounting bolts are properly installed; and b. Seal material shows no evidence of deterioration due to holes, ruptures, chemical attack, abrasion, radiation damage, or changes in physical appearance.	18 months

3.6 CONTAINMENT SYSTEMS

3.6.14 Containment Recirculation Drains

LCO 3.6.14 The ice condenser floor drains and the refueling canal drains shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One ice condenser floor drain inoperable.	A.1	Restore ice condenser floor drain to OPERABLE status.	1 hour
B. One refueling canal drain inoperable.	B.1	Restore refueling canal drain to OPERABLE status.	1 hour
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.14.1	Verify, by visual inspection, that: a. Each refueling canal drain plug is removed; b. Each refueling canal drain is not obstructed by debris; and c. No debris is present in the upper compartment or refueling canal that could obstruct the refueling canal drain.	92 days <u>AND</u> Prior to entering MODE 4 from MODE 5 after each partial or complete fill of the canal
SR 3.6.14.2	Verify for each ice condenser floor drain that the: a. Gate opening is not impaired by ice, frost, or debris; b. Gate seat shows no evidence of damage; c. Gate opening force is ≤ 100 lb; and d. Drain line from the ice condenser floor to the lower compartment is unrestricted.	18 months

3.6 CONTAINMENT SYSTEMS

3.6.15 Shield Building

LCO 3.6.15 The shield building shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Shield building inoperable.	A.1	Restore shield building to OPERABLE status.	24 hours
B. ----------NOTE---------- Annulus pressure requirement is not applicable during ventilating operations, required annulus entries, or Auxiliary Building isolations not exceeding 1 hour in duration. ---------- Annulus pressure not within limits.	B.1	Restore annulus pressure within limits.	8 hours
C. Required Action and associated Completion Time not met.	C.1 <u>AND</u> C.2	Be in MODE 3. Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.15.1	Verify annulus negative pressure is equal to or more negative than -5 inches water gauge with respect to the atmosphere.	12 hours
SR 3.6.15.2	Verify the door in each access opening is closed, except when the access opening is being used for normal transient entry and exit.	31 days
SR 3.6.15.3	Verify shield building structural integrity by performing a visual inspection of the exposed interior and exterior surfaces of the Shield Building.	During shutdown for SR 3.6.1.1 Type A tests
SR 3.6.15.4	Verify each Emergency Gas Treatment System train with final flow ≥ 3600 cfm and ≤ 4400 cfm produces an annulus pressure equal to or more negative than - 0.61 inch water gauge at elevation 783 with respect to the atmosphere and with an inleakage of ≤ 250 cfm.	18 months on a STAGGERED TEST BASIS

3.7 PLANT SYSTEMS

3.7.1 Main Steam Safety Valves (MSSVs)

LCO 3.7.1 Five MSSVs per steam generator shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more steam generators with one MSSV inoperable.	A.1	Reduce THERMAL POWER to ≤ 58 % RTP.	4 hours
B. One or more steam generators with two or more MSSVs inoperable.	B.1	Reduce THERMAL POWER to less than or equal to the Maximum Allowable % RTP specified in Table 3.7.1-1 for the number of OPERABLE MSSVs.	4 hours
	AND		
		----------NOTE---------- Only required in MODE 1. ----------	
	B.2	Reduce the Power Range Neutron Flux - High reactor trip setpoint to less than or equal to the Maximum Allowable % RTP specified in Table 3.7.1-1 for the number of OPERABLE MSSVs.	36 Hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time not met. <u>OR</u> One or more steam generators with ≥ 4 MSSVs inoperable.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	----------NOTE---------- Only required to be performed in MODES 1 and 2. ---------- Verify each required MSSV lift setpoint per Table 3.7.1-2 in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1%.	In accordance with the Inservice Testing Program

Table 3.7.1-1

OPERABLE Main Steam Safety Valves Versus Maximum Allowable Power

NUMBER OF OPERABLE MSSVs PER STEAM GENERATOR	MAXIMUM ALLOWABLE POWER (% RTP)
3	≤ 41
2	≤ 25

Table 3.7.1-2

Main Steam Safety Valve Lift Settings

VALVE NUMBER				LIFT SETTING (psig ± 3%)
STEAM GENERATOR				
#1	#2	#3	#4	
2-522	2-517	2-512	2-527	1224
2-523	2-518	2-513	2-528	1215
2-524	2-519	2-514	2-529	1205
2-525	2-520	2-515	2-530	1195
2-526	2-521	2-516	2-531	1185

3.7 PLANT SYSTEMS

3.7.2 Main Steam Isolation Valves (MSIVs)

LCO 3.7.2 Four MSIVs shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 except when all MSIVs are closed and de-activated.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One MSIV inoperable in MODE 1.	A.1	Restore MSIV to OPERABLE status.	8 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 2.	6 hours
C. ----------NOTE---------- Separate Condition entry is allowed for each MSIV. ---------- One or more MSIVs inoperable in MODE 2 or 3.	C.1 AND C.2	Close MSIV. Verify MSIV is closed and de-activated.	8 hours Once per 7 days
D. Required Action and associated Completion Time of Condition C not met.	D.1 AND D.2	Be in MODE 3. Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	----------NOTE---------- Required to be performed in MODES 1 & 2. ---------- Verify closure time of each MSIV is ≤ 6.0 seconds on an actual or simulated actuation signal.	In accordance with the Inservice Testing Program or 18 months

3.7 PLANT SYSTEMS

3.7.3 Main Feedwater Isolation Valves (MFIVs) and Main Feedwater Regulation Valves (MFRVs) and Associated Bypass Valves

LCO 3.7.3 Four MFIVs, four MFRVs, and associated bypass valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3 except when MFIV, MFRV, or associated bypass valve is closed and de-activated or isolated by a closed manual valve.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more MFIVs inoperable.	A.1	Close or isolate MFIV.	72 hours
	AND		
	A.2	Verify MFIV is closed or isolated.	Once per 7 days
B. One or more MFRVs inoperable.	B.1	Close or isolate MFRV.	72 hours
	AND		
	B.2	Verify MFRV is closed or isolated.	Once per 7 days
C. One or more MFIV or MFRV bypass valves inoperable.	C.1	Restore bypass valve to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One MFIV and MFRV in the same flow path inoperable.	D.1	Isolate affected flow path.	8 hours
E. One MFIV bypass valve and MFRV bypass valve in the same flow path inoperable.	E.1	Restore one MFIV bypass valve or MFRV bypass valve to OPERABLE status.	8 hours
F. Required Action and associated Completion Time not met.	F.1	Be in MODE 3.	6 hours
	AND		
	F.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	Verify the closure time of each MFIV, MFRV, and associated bypass valve is ≤ 6.5 seconds on an actual or simulated actuation signal.	In accordance with the Inservice Testing Program or 18 months

3.7 PLANT SYSTEMS

3.7.4 Atmospheric Dump Valves (ADVs)

LCO 3.7.4 Four ADV lines shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 when steam generator is relied upon for heat removal.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required ADV line inoperable.	A.1	Restore required ADV line to OPERABLE status.	7 days
B. One train (two ADV lines) inoperable due to one train of ACAS inoperable.	B.1	Restore ADV lines to OPERABLE status.	72 hours
C. Two or more required ADV lines inoperable for reasons other than Condition B.	C.1	Restore all but one ADV line to OPERABLE status.	24 hours
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 4 without reliance upon steam generator for heat removal.	18 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Verify one complete cycle of each ADV.	18 months
SR 3.7.4.2	Verify one complete cycle of each ADV block valve.	18 months

3.7 PLANT SYSTEMS

3.7.5 Auxiliary Feedwater (AFW) System

LCO 3.7.5 Three AFW trains shall be OPERABLE.

----------NOTE----------
Only one AFW train, which includes a motor driven pump, is required to be OPERABLE in MODE 4.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 when steam generator is relied upon for heat removal.

ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable when entering MODE 1.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One steam supply to turbine driven AFW pump inoperable.	A.1 Restore steam supply to OPERABLE status.	7 days AND 10 days from discovery of failure to meet the LCO
B. One AFW train inoperable in MODE 1, 2 or 3 for reasons other than Condition A.	B.1 Restore AFW train to OPERABLE status.	72 hours AND 10 days from discovery of failure to meet the LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time for Condition A or B not met. <u>OR</u> Two AFW trains inoperable in MODE 1, 2, or 3.	C.1 <u>AND</u> C.2	Be in MODE 3. Be in MODE 4.	6 hours 18 hours
D. Three AFW trains inoperable in MODE 1, 2, or 3.	D.1	----------NOTE---------- LCO 3.0.3 and all other LCO Required Actions requiring MODE changes are suspended until one AFW train is restored to OPERABLE status. ---------- Initiate action to restore one AFW train to OPERABLE status.	 Immediately
E. Required AFW train inoperable in MODE 4.	E.1	Initiate action to restore AFW train to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	Verify each AFW manual, power operated, and automatic valve in each water flow path, and in both steam supply flow paths to the steam turbine driven pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.5.2	----------NOTE---------- Not required to be performed for the turbine driven AFW pump until 24 hours after ≥ 1092 psig in the steam generator. ---------- Verify the developed head of each AFW pump at the flow test point is greater than or equal to the required developed head.	31 days on a STAGGERED TEST BASIS
SR 3.7.5.3	----------NOTE---------- Not applicable in MODE 4 when steam generator is relied upon for heat removal. ---------- Verify each AFW automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	18 months
SR 3.7.5.4	----------NOTE---------- 1. Not required to be performed for the turbine driven AFW pump until 24 hours after ≥ 1092 psig in the steam generator. 2. Not applicable in MODE 4 when steam generator is relied upon for heat removal. ---------- Verify each AFW pump starts automatically on an actual or simulated actuation signal.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.5.5	Verify proper alignment of the required AFW flow paths by verifying flow from the condensate storage tank to each steam generator.	Prior to entering MODE 2 after initial fuel loading and whenever unit has been in MODE 5 or 6 for > 30 days

3.7 PLANT SYSTEMS

3.7.6 Condensate Storage Tank (CST)

LCO 3.7.6 The CST level shall be ≥ 200,000 gal.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 when steam generator is relied upon for heat removal.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. CST level not within limit.	A.1	Verify by administrative means OPERABILITY of ERCW backup water supply.	4 hours AND Once per 12 hours thereafter
	AND		
	A.2	Restore CST level to within limit.	7 days
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 4, without reliance on steam generator for heat removal.	18 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify the CST level is ≥ 200,000 gal.	12 hours

3.7 PLANT SYSTEMS

3.7.7 Component Cooling System (CCS)

LCO 3.7.7 Two CCS trains shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One CCS train inoperable.	A.1	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops-MODE 4," for residual heat removal loops made inoperable by CCS. ---------- Restore CCS train to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	Verify that the alternate feeder breaker to the C-S pump is open.	7 days
SR 3.7.7.2	----------NOTE---------- Isolation of CCS flow to individual components does not render the CCS inoperable. ---------- Verify each CCS manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.7.3	Verify each CCS automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	18 months
SR 3.7.7.4	----------NOTE---------- Verification of CCS pump 1B-B automatic start on SI is not required when CCS pump 1B-B is supporting CCS Train B OPERABILITY. ---------- Verify each CCS pump starts automatically on an actual or simulated actuation signal.	18 months
SR 3.7.7.5	----------NOTE---------- Only required to be met when CCS pump 1B-B is supporting CCS Train B OPERABILITY. ---------- Verify CCS pump 1B-B is aligned to CCS Train B and is in operation.	12 hours

3.7 PLANT SYSTEMS

3.7.8 Essential Raw Cooling Water (ERCW) System

LCO 3.7.8 Two ERCW trains shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One ERCW train inoperable.	A.1	----------NOTES---------- 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources- Operating," for diesel generator made inoperable by ERCW. 2. Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops-MODE 4," for residual heat removal loops made inoperable by ERCW. ---------- Restore ERCW train to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.8.1	----------NOTE---------- Isolation of ERCW flow to individual components does not render the ERCW inoperable. ---------- Verify each ERCW manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.8.2	Verify each ERCW automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	18 months
SR 3.7.8.3	Verify each ERCW pump starts automatically on an actual or simulated actuation signal.	18 months

3.7 PLANT SYSTEMS

3.7.9 Ultimate Heat Sink (UHS)

LCO 3.7.9 The UHS shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. UHS inoperable.	A.1 Be in MODE 3.	6 hours
	AND	
	A.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.9.1	Verify average water temperature of UHS is ≤ 85°F.	24 hours

3.7 PLANT SYSTEMS

3.7.10 Control Room Emergency Ventilation System (CREVS)

LCO 3.7.10 Two CREVS trains shall be OPERABLE.

----------NOTE----------
The control room envelope (CRE) boundary may be opened intermittently under administrative control.

APPLICABILITY: MODES 1, 2, 3, 4, 5, and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One CREVS train inoperable for reasons other than Condition B.	A.1	Restore CREVS train to OPERABLE status.	7 days
B. One or more CREVS trains inoperable due to inoperable CRE boundary in MODE 1, 2, 3, or 4.	B.1	Initiate action to implement mitigating actions.	Immediately
	AND		
	B.2	Verify mitigating actions ensure CRE occupant exposures to radiological and chemical hazards will not exceed limits and CRE occupants are protected from smoke hazards.	24 hours
	AND		
	B.3	Restore CRE boundary to OPERABLE status.	90 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met in MODE 1, 2, 3, or 4.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 5.	36 hours
D. Required Action and associated Completion Time of Condition A not met in MODE 5 or 6, or during movement of irradiated fuel assemblies.	D.1	Place OPERABLE CREVS train in emergency mode.	Immediately
	OR		
	D.2	Suspend movement of irradiated fuel assemblies.	Immediately
E. Two CREVS trains inoperable in MODE 1, 2, 3, or 4 due to actions taken as a result of a tornado warning.	E.1	Restore one CREVS train to OPERABLE status.	8 hours
F. Two CREVS trains inoperable in MODE 5 or 6, or during movement of irradiated fuel assemblies. OR One or more CREVS trains inoperable due to inoperable CRE boundary in MODE 5 or 6, or during movement of irradiated fuel assemblies.	F.1	Suspend movement of irradiated fuel assemblies.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Two CREVS trains inoperable in MODE 1, 2, 3, or 4 for reasons other than Condition B or E.	G.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.10.1	Operate each CREVS train for ≥ 15 minutes.	31 days
SR 3.7.10.2	Perform required CREVS filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.7.10.3	Verify each CREVS train actuates on an actual or simulated actuation signal.	18 months
SR 3.7.10.4	Perform required CRE unfiltered air inleakge testing in accordance with the Control Room Envelope Habitability Program.	In accordance with the Control Room Envelope Habitability Program

3.7 PLANT SYSTEMS

3.7.11 Control Room Emergency Air Temperature Control System (CREATCS)

LCO 3.7.11 Two CREATCS trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, 4, 5, and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One CREATCS train inoperable.	A.1	Restore CREATCS train to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met in MODE 1, 2, 3, or 4.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours
C. Required Action and associated Completion Time of Condition A not met in MODE 5 or 6, or during movement of irradiated fuel assemblies.	C.1	Place OPERABLE CREATCS train in operation.	Immediately
	OR		
	C.2	Suspend movement of irradiated fuel assemblies.	Immediately
D. Two CREATCS trains inoperable in MODE 5 or 6, or during movement of irradiated fuel assemblies.	D.1	Suspend movement of irradiated fuel assemblies	Immediately
E. Two CREATCS trains inoperable in MODE 1, 2, 3, or 4.	E.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.11.1	Verify each CREATCS train has the capability to remove the assumed heat load.	18 months

3.7 PLANT SYSTEMS

3.7.12 Auxiliary Building Gas Treatment System (ABGTS)

LCO 3.7.12 Two ABGTS trains shall be OPERABLE

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One ABGTS train inoperable	A.1	Restore ABGTS train to OPERABLE status.	7 days
B. Required Action and associated Completion Time of Condition A not met. OR Two ABGTS trains inoperable.	B.1 AND B.2	Be in MODE 3. Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.12.1	Operate each ABGTS train for ≥ 10 continuous hours with the heaters operating.	31 days
SR 3.7.12.2	Perform required ABGTS filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.7.12.3	Verify each ABGTS train actuates on an actual or simulated actuation signal.	18 months
SR 3.7.12.4	Verify one ABGTS train can maintain a pressure between -0.25 inches and -0.5 inches water gauge with respect to atmospheric pressure during the post accident mode of operation at a flow rate ≥ 9300 cfm and ≤ 9900 cfm.	18 months on a STAGGERED TEST BASIS

3.7 PLANT SYSTEMS

3.7.13 Fuel Storage Pool Water Level

LCO 3.7.13 The fuel storage pool water level shall be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: During movement of irradiated fuel assemblies in the fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Fuel storage pool water level not within limit.	A.1 ----------NOTE---------- LCO 3.0.3 is not applicable. ---------- Suspend movement of irradiated fuel assemblies in the fuel storage pool.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.13.1	Verify the fuel storage pool water level is ≥ 23 ft above the top of the irradiated fuel assemblies seated in the storage racks.	7 days

3.7 PLANT SYSTEMS

3.7.14 Secondary Specific Activity

LCO 3.7.14 The specific activity of the secondary coolant shall be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Specific activity not within limit.	A.1 Be in MODE 3. AND A.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.14.1	Verify the specific activity of the secondary coolant is ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131.	31 days

3.7 PLANT SYSTEMS

3.7.15 Spent Fuel Assembly Storage

LCO 3.7.15 The combination of initial enrichment and burnup of each spent fuel assembly stored shall be in accordance with Specification 4.3.1.1.

APPLICABILITY: Whenever any fuel assembly is stored in the spent fuel storage pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 ----------NOTE---------- LCO 3.0.3 is not applicable. ---------- Initiate action to move the noncomplying fuel assembly.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.15.1	Verify by administrative means the initial enrichment and burnup of the fuel assembly is in accordance with Specification 4.3.1.1.	Prior to storing the fuel assembly.

3.7 PLANT SYSTEMS

3.7.16 Component Cooling System (CCS) - Shutdown

LCO 3.7.16 Two CCS trains shall be OPERABLE with one pump powered from Train A and aligned to the Train A header, and two pumps powered from Train B and aligned to the Train B header.

APPLICABILITY: MODES 4 and 5.

----------NOTE----------
This LCO is not applicable more than 48 hours after entry into MODE 3 from MODE 1 or 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CCS train inoperable in MODE 4. AND Complying with Required Actions to be in MODE 5.	A.1 Be in MODE 5.	24 hours
B. One CCS train inoperable in MODE 4 for reasons other than Condition A.	B.1 Verify two OPERABLE reactor coolant system (RCS) loops and one RCS loop in operation. AND B.2 Verify T_{avg} > 200ºF.	Once per 12 hours Once per 12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two CCS trains inoperable in MODE 4.	C.1 ----------NOTES---------- 1. LCO 3.0.3 and all other LCO Required Actions requiring MODE changes are suspended until one CCS train is restored to an OPERABLE status. 2. Enter Conditions and Required Actions of LCO 3.4.6, “RCS Loops - MODE 4,” for residual heat removal (RHR) loops made inoperable by CCS. ---------- Initiate action to restore one CCS train to OPERABLE status.	Immediately
D. One or more CCS train(s) inoperable in MODE 5.	D.1 ----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," for RHR loops made inoperable by CCS. ---------- Initiate action to restore CCS train(s) to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.16.1	Verify correct breaker alignment and indicated power available to the required pump(s) that is not in operation.	12 hours
SR 3.7.16.2	Verify two CCS pumps are aligned to CCS Train B.	12 hours

3.7 PLANT SYSTEMS

3.7.17 Essential Raw Cooling Water (ERCW) System - Shutdown

LCO 3.7.17 Two ERCW trains shall be OPERABLE as follows:

a. Three ERCW pumps aligned to Train A, including two pumps capable of being powered from 6.9 kV Shutdown Board 2A-A, and

b. Three ERCW pumps aligned to Train B, including two pumps capable of being powered from 6.9 kV Shutdown Board 2B-B.

APPLICABILITY: MODES 4 and 5.

----------NOTE----------
This LCO is not applicable more than 48 hours after entry into MODE 3 from MODE 1 or 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One ERCW train inoperable in MODE 4. <u>AND</u> Complying with Required Actions to be in MODE 5.	A.1 Be in MODE 5.	24 hours
B. One ERCW train inoperable in MODE 4 for reasons other than Condition A.	B.1 Verify two OPERABLE reactor coolant system (RCS) loops and one RCS loop in operation. <u>AND</u> B.2 Verify T_{avg} > 200ºF.	Once per 12 hours Once per 12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two ERCW trains inoperable in MODE 4.	C.1 ----------NOTES---------- 1. LCO 3.0.3 and all other LCO Required Actions requiring MODE changes are suspended until one ERCW train is restored to an OPERABLE status. 2. Enter Conditions and Required Actions of LCO 3.4.6, “RCS Loops - MODE 4,” for residual heat removal (RHR) loops made inoperable by ERCW. ---------- Initiate action to restore one ERCW train to OPERABLE status.	Immediately
D. One or more ERCW train(s) inoperable in MODE 5.	D.1 ----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," for RHR loops made inoperable by ERCW. ---------- Initiate action to restore ERCW train(s) to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.17.1	Verify correct breaker alignment and indicated power available to the required pump(s) that is not in operation.	12 hours

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources - Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System; and

b. Four diesel generators (DGs) capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

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

ACTIONS

----------NOTE----------
LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for required OPERABLE offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND		
	A.2	Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.3	Restore required offsite circuit to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO
B. One or more DG(s) in Train A inoperable. OR One or more DG(s) in Train B inoperable.	B.1	Perform SR 3.8.1.1 for the required offsite circuits.	1 hour AND Once per 8 hours thereafter
	AND		
	B.2	Declare required feature(s) supported by the inoperable DG(s) inoperable when its required redundant feature(s) is inoperable	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.3.1	Determine OPERABLE DG(s) is not inoperable due to common cause failure.	24 hours
	OR		
	B.3.2	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.4	Restore DG(s) to OPERABLE status.	72 hours AND 6 days from discovery of failure to meet LCO
C. Two required offsite circuits inoperable.	C.1	Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	AND		
	C.2	Restore one required offsite circuit to OPERABLE status.	24 hours
D. One required offsite circuit inoperable. AND One or more DG(s) in Train A inoperable. OR One or more DG(s) in Train B inoperable.	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," when Condition D is entered with no AC power source to any train. ----------		
	D.1	Restore required offsite circuit to OPERABLE status.	12 hours
	OR		
	D.2	Restore required DG(s) to OPERABLE status.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. One or more DG(s) in Train A inoperable. AND One or more DG(s) in Train B inoperable.	E.1 E.2	Restore DGs in Train A to OPERABLE status. OR Restore DGs in Train B to OPERABLE status.	2 hours 2 hours
F. Required Action and Associated Completion Time of Condition A. B, C, D, or E not met.	F.1 AND F.2	Be in MODE 3. Be in MODE 5.	6 hours 36 hours
G. Two required offsite circuits inoperable. AND One or more DG(s) in Train A inoperable. OR One or more DG(s) in Train B inoperable.	G.1	Enter LCO 3.0.3.	Immediately
H. One required offsite circuit inoperable. AND One or more DG(s) in Train A inoperable. AND One or more DG(s) in Train B inoperable.	H.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	7 days
SR 3.8.1.2	----------NOTES---------- 1. Performance of SR 3.8.1.7 satisfies this SR. 2. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.7 must be met. ---------- Verify each DG starts from standby conditions and achieves steady state voltage ≥ 6800 V and ≤ 7260 V, and frequency 60 Hz nominal.	As specified in Table 3.8.1-1
SR 3.8.1.3	----------NOTES---------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.2 or SR 3.8.1.7. ---------- Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 3960 kW and ≤ 4400 kW.	As specified in Table 3.8.1-1
SR 3.8.1.4	Verify each skid mounted day tank contains ≥ 218.5 gal of fuel oil.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.5	Check for and remove accumulated water from each skid mounted day tank.	31 days
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from 7 day storage tank to the skid mounted day tank.	31 days
SR 3.8.1.7	Verify each DG starts from standby condition and achieves in ≤ 10 seconds, voltage ≥ 6800 V, and frequency ≥ 58.8 Hz. Verify after DG fast start from standby conditions that the DG achieves steady state voltage ≥ 6800 V and ≤ 7260 V, and frequency ≥ 59.8 Hz and ≤ 60.1 Hz.	184 days
SR 3.8.1.8	----------NOTES---------- 1. For the 2A-A and 2B-B Shutdown Boards, this Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. 2. Transfer capability is only required to be met for 6.9kV shutdown boards that require normal and alternate power supplies. ---------- Verify automatic and manual transfer of each 6.9 kV shutdown board power supply from the normal offsite circuit to the alternate offsite circuit.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	----------NOTES---------- 1. For DGs 2A-A and 2B-B, this Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. 2. If performed with the DG synchronized with offsite power, it shall be performed at a power factor ≥ 0.8 and ≤ 0.9. ---------- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 66.75 Hz; b. Within 3 seconds following load rejection, the voltage is ≥ 6555 V and ≤ 7260 V; and c. Within 4 seconds following load rejection, the frequency is ≥ 59.8 Hz and ≤ 60.1 Hz.	18 months
SR 3.8.1.10	----------NOTE---------- For DGs 2A-A and 2B-B, this Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG operating at a power factor ≥ 0.8 and ≤ 0.9 does not trip and voltage is maintained ≤ 8880 V during and following a load rejection of ≥ 3960 kW and ≤ 4400 kW and ≥ 2970 kVAR and ≤ 3300 kVAR.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	----------NOTE---------- For DGs 2A-A and 2B-B, this Surveillance shall not be performed in MODE 1, 2, 3, or 4. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. energizes auto-connected shutdown loads through automatic load sequencer, 3. maintains steady state voltage ≥ 6800 V and ≤ 7260 V, 4. maintains steady state frequency ≥ 59.8 Hz and ≤ 60.1 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	----------NOTE---------- For DGs 2A-A and 2B-B, this Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify on an actual or simulated Engineered Safety Feature (ESF) actuation signal each Unit 2 DG auto-starts from standby condition and: a. In ≤ 10 seconds after auto-start and during tests, achieves voltage ≥ 6800 V and frequency ≥ 58.8 Hz; b. After DG fast start from standby conditions the DG achieves steady state voltage ≥ 6800 V and ≤ 7260 V, and frequency ≥ 59.8 Hz and ≤ 60.1 Hz. c. Operates for ≥ 5 minutes; d. Permanently connected loads remain energized from the offsite power system; and e. Emergency loads are energized from the offsite power system.	18 months
SR 3.8.1.13	----------NOTE---------- For DGs 2A-A and 2B-B, this Surveillance shall not be performed in MODE 1 or 2. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG's automatic trips are bypassed on automatic or emergency start signal except: a. Engine overspeed; and b. Generator differential current	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.14	----------NOTES---------- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. For performance of this test in MODE 1, 2, 3 or 4, three DGs must be maintained operable and in a standby condition. 3. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG operating at a power factor ≥ 0.8 and ≤ 0.9 operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 4620 kW and ≤ 4840 kW and ≥ 3465 kVAR and ≤ 3630 kVAR; and b. For the remaining hours of the test loaded ≥ 3960 kW and ≤ 4400 kW and ≥ 2970 kVAR and ≤ 3300 kVAR.	18 months
SR 3.8.1.15	----------NOTES---------- This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 3960 kW and ≤ 4400 kW. Momentary transients outside of load range do not invalidate this test. ---------- Verify each DG starts and achieves, in ≤ 10 seconds, voltage ≥ 6800 V, and frequency ≥ 58.8 Hz. Verify after DG fast start from standby conditions that the DG achieves steady state voltage ≥ 6800 V and ≤ 7260 V, and frequency ≥ 59.8 Hz and ≤ 60.1 Hz.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.16	----------NOTE---------- For DGs 2A-A and 2B-B, this Surveillance shall not be performed in MODE 1, 2, 3, or 4. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify each DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	18 months
SR 3.8.1.17	----------NOTE---------- For DGs 2A-A and 2B-B, this Surveillance shall not be performed in MODE 1, 2, 3, or 4. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify, DG 2A-A and 2B-B operating in test mode and connected to its bus, an actual or simulated ESF actuation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.18	----------NOTE---------- For DGs 2A-A and 2B-B, this Surveillance shall not be performed in MODE 1, 2, 3, or 4. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify the time delay setting for each sequenced load block is within limits for each accident condition and non-accident condition load sequence.	18 months
SR 3.8.1.19	----------NOTE---------- For DGs 2A-A and 2B-B, this Surveillance shall not be performed in MODE 1, 2, 3, or 4. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ESF actuation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. energizes auto-connected emergency loads through load sequencer, 3. achieves steady state voltage: ≥ 6800 V and ≤ 7260 V, 4. achieves steady state frequency ≥ 59.8 Hz and ≤ 60.1 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.20	Verify during idle operation that any automatic or emergency start signal disables the idle start circuitry and commands the engine to full speed.	18 months
SR 3.8.1.21	Verify when started simultaneously from standby condition, each DG achieves, in ≤ 10 seconds, voltage ≥ 6800 V and frequency ≥ 58.8 Hz. Verify after DG fast start from standby conditions that the DG achieves steady state voltage ≥ 6800 V and ≤ 7260 V, and frequency ≥ 59.8 Hz and ≤ 60.1 Hz.	10 years
SR 3.8.1.22	---------- NOTES ---------- 1. For the 2B and 2C Unit Boards, this Surveillance shall not normally be performed in MODE 1 or 2. However, this Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. 2. Transfer capability is only required to be met for 6.9kV Unit Boards that require normal and alternate power supplies. --- Verify automatic transfer of each 6.9kV Unit Board 1B, 1C, 2B and 2C power supply from the normal power supply to the alternate power supply.	18 months

Table 3.8.1-1 (page 1 of 1)
Diesel Generator Test Schedule

NUMBER OF FAILURES IN LAST 25 VALID TESTS[a]	FREQUENCY
≤ 3	31 days
≥ 4	7 days[b] (but no less than 24 hours)

(a) Criteria for determining number of failures and valid tests shall be in accordance with Regulatory Position C.2.1 of Regulatory Guide 1.9, Revision 3, where the number of tests and failures is determined on a per DG basis.

(b) This test frequency shall be maintained until seven consecutive failure free starts from standby conditions and load and run tests have been performed. If, subsequent to the 7 failure free tests, 1 or more additional failures occur, such that there are again 4 or more failures in the last 25 tests, the testing interval shall again be reduced as noted above and maintained until 7 consecutive failure free tests have been performed.

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources - Shutdown

LCO 3.8.2 The following AC electrical power sources shall be OPERABLE:

a. One qualified circuit between the offsite transmission network and the onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.10, "Distribution Systems-Shutdown;" and

b. Two diesel generators (DGs) either Train A or Train B capable of supplying one train of the onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.10.

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.8.10, with one required train de-energized as a result of Condition A. ---------- A.1 Declare affected required feature(s) with no offsite power available inoperable. <u>OR</u> A.2.1 Suspend CORE ALTERATIONS <u>AND</u>	 Immediately Immediately (continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2.2	Suspend movement of irradiated fuel assemblies.	Immediately
	AND		
	A.2.3	Initiate action to suspend operations involving positive reactivity additions.	Immediately
	AND		
	A.2.4	Initiate action to restore required offsite power circuit to OPERABLE status.	Immediately
B. One required DG inoperable.	B.1	Suspend CORE ALTERATIONS.	Immediately
	AND		
	B.2	Suspend movement of irradiated fuel assemblies.	Immediately
	AND		
	B.3	Initiate action to suspend operations involving positive reactivity additions.	Immediately
	AND		
	B.4	Initiate action to restore required DG to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.2.1	----------NOTE---------- The following SRs are not required to be performed: SR 3.8.1.3, SR 3.8.1.6, SR 3.8.1.9 through SR 3.8.1.16, SR 3.8.1.18 and SR 3.8.1.19. ---------- For AC sources required to be OPERABLE, the SRs of Specification 3.8.1, "AC Sources-Operating," except SR 3.8.1.8, SR 3.8.1.17, and SR 3.8.1.21, are applicable.	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Diesel Fuel Oil, Lube Oil, and Starting Air

LCO 3.8.3 The stored diesel fuel oil, lube oil, and starting air subsystem shall be within limits for each required diesel generator (DG).

APPLICABILITY: When associated DG is required to be OPERABLE.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more DGs with fuel level < 56,754 gal and > 48,648 gal in storage tank.	A.1	Restore fuel oil level to within limits.	48 hours
B. One or more diesel engines with lube oil inventory < 287 gal and > 267 gal.	B.1	Restore lube oil inventory to within limits.	48 hours
C. One or more DGs with stored fuel oil total particulates not within limit.	C.1	Restore fuel oil total particulates within limit.	7 days
D. One or more DGs with new fuel oil properties not within limits.	D.1	Restore stored fuel oil properties to within limits.	30 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. One or more DGs with starting air receiver pressure < 190 psig and ≥ 170 psig.	E.1 Restore starting air receiver pressure to ≥ 190 psig.	48 hours
F. Required Action and associated Completion Time not met. OR One or more DGs diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than Condition A, B, C, D, or E.	F.1 Declare associated DG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	Verify each 7 day fuel oil storage tank contains ≥ 56,754 gal of fuel.	31 days
SR 3.8.3.2	Verify lubricating oil inventory is ≥ 287 gal per engine.	31 days
SR 3.8.3.3	Verify fuel oil properties of new and stored fuel oil are tested in accordance with, and maintained within the limits of, the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program
SR 3.8.3.4	Verify each DG air start receiver pressure is ≥ 190 psig.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.3.5	Check for and remove accumulated water from each of the four interconnected tanks which constitute the 7 day fuel oil storage tank.	31 days
SR 3.8.3.6	Perform a visual inspection for leaks in the exposed fuel oil system piping while the DG is running.	18 months
SR 3.8.3.7	For each of the four interconnected tanks which constitute the 7 day fuel oil storage tank: a. Drain the fuel oil; b. Remove the sediment; and c. Clean the tank.	10 years

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources - Operating

LCO 3.8.4 Four channels of vital DC and four Diesel Generator (DG) DC electrical power subsystems shall be OPERABLE.

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

Vital Battery V may be substituted for any of the required vital batteries.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One vital DC electrical power subsystem inoperable.	A.1	Restore vital DC electrical power subsystem to OPERABLE status.	2 hours
B. Required Action and Associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours
C. One DG DC electrical power subsystem inoperable.	C.1	Restore DG DC electrical power subsystem to OPERABLE status.	2 hours
D. Required Action and Associated Completion Time of Condition C not met.	D.1	Declare associated DG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify vital battery terminal voltage is ≥ 128 V (132 V for vital battery V) on float charge.	7 days
SR 3.8.4.2	Verify DG battery terminal voltage is ≥ 124 V on float charge.	7 days
SR 3.8.4.3	Verify for the vital batteries that the alternate feeder breakers to each required battery charger are open.	7 days
SR 3.8.4.4	Verify correct breaker alignment and indicated power availability for each DG 125 V DC distribution panel and associated battery charger	7 days
SR 3.8.4.5	Verify no visible corrosion at terminals and connectors for the vital batteries. OR Verify connection resistance for the vital batteries is ≤ 80 E-6 ohm for inter-cell connections, ≤ 50 E-6 ohm for inter-rack connections, ≤ 120 E-6 ohm for inter-tier connections, and ≤ 50 E-6 ohm for terminal connections.	92 days
SR 3.8.4.6	Verify no visible corrosion at terminals and connectors for the DG batteries. OR Verify connection resistance for the DG batteries is ≤ 80 E-6 ohm for inter-cell connections, ≤ 50 E-6 ohm for inter-tier connections, and ≤ 50 E-6 ohm for terminal connections.	92 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.7	Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration.	12 months
SR 3.8.4.8	Remove visible terminal corrosion and verify battery cell to cell and terminal connections are coated with anti-corrosion material.	12 months
SR 3.8.4.9	Verify connection resistance for the vital batteries is ≤ 80 E-6 ohm for inter-cell connections, ≤ 50 E-6 ohm for inter-rack connections, ≤ 120 E-6 ohm for inter-tier connections, and ≤ 50 E-6 ohm for terminal connections.	12 months
SR 3.8.4.10	Verify connection resistance for the DG batteries is ≤ 80 E-6 ohm for inter-cell connections, ≤ 50 E-6 ohm for inter-tier connections, and ≤ 50 E-6 ohm for terminal connections.	12 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.11	----------NOTE---------- This Surveillance is normally not performed in MODE 1, 2, 3, or 4. However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify each vital battery charger is capable of recharging its associated battery from a service or capacity discharge test while supplying normal loads. <u>OR</u> Verify each vital battery charger is capable of operating for ≥ 4 hours at current limit 220 – 250 amps.	18 months
SR 3.8.4.12	----------NOTE---------- Credit may be taken for unplanned events that satisfy this SR. ---------- Verify each diesel generator battery charger is capable of recharging its associated battery from a service or capacity discharge test while supplying normal loads.	18 months
SR 3.8.4.13	----------NOTES---------- 1. The modified performance discharge test in SR 3.8.4.14 may be performed in lieu of the service test in SR 3.8.4.13 once per 60 months. 2. This Surveillance is not performed in MODE 1, 2, 3, or 4 for required vital batteries. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads and any connected nonsafety loads for the design duty cycle when subjected to a battery service test.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.14	----------NOTE---------- This Surveillance is not performed in MODE 1, 2, 3, or 4 for required vital batteries. Credit may be taken for unplanned events that satisfy this SR. ---------- Verify battery capacity is ≥ 80% of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test.	60 months <u>AND</u> 12 months when battery shows degradation or has reached 85% of expected life with capacity < 100% of manufacturer's rating <u>AND</u> 24 months when battery has reached 85% of the expected life with capacity ≥ 100% of manufacturer's rating

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 DC Sources - Shutdown

LCO 3.8.5 Vital DC and Diesel Generator (DG) DC electrical power subsystems shall be OPERABLE to support the DC electrical power distribution subsystem(s) required by LCO 3.8.10, "Distribution Systems - Shutdown" and to support the Diesel Generators (DGs) required by LCO 3.8.2, "AC Sources - Shutdown."

----------NOTES----------
Vital Battery V may be substituted for any of the required vital batteries.

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required vital DC electrical power subsystems inoperable.	A.1.1 Declare affected required feature(s) inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2.2	Suspend movement of irradiated fuel assemblies.	Immediately
	AND		
	A.2.3	Initiate action to suspend operations involving positive reactivity additions.	Immediately
	AND		
	A.2.4	Initiate action to restore required vital DC electrical power subsystems to OPERABLE status.	Immediately
B. One or more required DG DC electrical power subsystems inoperable.	B.1	Declare associated DG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.5.1	----------NOTE---------- The following SRs are not required to be performed: SR 3.8.4.11, SR 3.8.4.12, SR 3.8.4.13, and SR 3.8.4.14. ---------- For DC sources required to be OPERABLE, the following SRs are applicable: SR 3.8.4.1 SR 3.8.4.6 SR 3.8.4.11 SR 3.8.4.2 SR 3.8.4.7 SR 3.8.4.12 SR 3.8.4.3 SR 3.8.4.8 SR 3.8.4.13 SR 3.8.4.4 SR 3.8.4.9 SR 3.8.4.14 SR 3.8.4.5 SR 3.8.4.10	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.6 Battery Cell Parameters

LCO 3.8.6 Battery cell parameters for 125 V vital batteries and 125 V diesel generator (DG) batteries shall be within the limits of Table 3.8.6-1.

APPLICABILITY: When associated DC electrical power subsystems and DGs are required to be OPERABLE.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each battery bank.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more batteries with one or more battery cell parameters not within Category A or B limits.	A.1	Verify pilot cells electrolyte level and float voltage meet Table 3.8.6-1 Category C limits.	1 hour
	AND		
	A.2	Verify battery cell parameters meet Table 3.8.6-1 Category C limits.	24 hours AND Once per 7 days thereafter
	AND		
	A.3	Restore battery cell parameters to category A and B limits of Table 3.8.6-1.	31 days

(continued)

(ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met. OR One or more batteries with average electrolyte temperature of the representative cells < 60°F for vital batteries and < 50°F for DG batteries. OR One or more batteries with one or more battery cell parameters not within Category C values.	B.1 Declare associated battery inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.6.1	Verify battery cell parameters meet Table 3.8.6-1 Category A limits.	7 days
SR 3.8.6.2	Verify battery cell parameters meet Table 3.8.6-1 Category B limits.	92 days AND Once within 24 hours after a battery discharge < 110 V for vital batteries (113.5 V for vital battery V) or 106.5 V for DG batteries AND Once within 24 hours after a battery overcharge > 150 V for vital batteries (155 V for vital battery V) or 145 V for DG batteries
SR 3.8.6.3	Verify average electrolyte temperature of representative cells is ≥ 60°F for vital batteries and ≥ 50°F for the DG batteries.	92 days

Table 3.8.6-1 (page 1 of 1)
Battery Cell Parameters Requirements

PARAMETER	CATEGORY A: LIMITS FOR EACH DESIGNATED PILOT CELL	CATEGORY B: LIMITS FOR EACH CONNECTED CELL	CATEGORY C: ALLOWABLE LIMIT FOR EACH CONNECTED CELL
Electrolyte Level	> Minimum level indication mark, and ≤ 1/4 inch above maximum level indication mark [(a)]	> Minimum level indication mark, and ≤ 1/4 inch above maximum level indication mark [(a)]	Above top of plates, and not overflowing
Float Voltage	≥ 2.13 V	≥ 2.13 V	> 2.07 V
Specific Gravity [(b)(c)]	≥ 1.200	≥ 1.195 AND Average of all connected cells > 1.205	Not more than 0.020 below average of all connected cells AND Average of all connected cells ≥ 1.195

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum level during equalizing charges provided it is not overflowing.

(b) Corrected for electrolyte temperature and level. Level correction is not required, however, when battery charging is < 2 amps when on float charge for vital batteries and < 1.0 amp for DG batteries.

(c) A battery charging current of < 2 amps when on float charge for vital batteries and < 1.0 amp for DG batteries is acceptable for meeting specific gravity limits following a battery recharge, for a maximum of 31 days. When charging current is used to satisfy specific gravity requirements, specific gravity of each connected cell shall be measured prior to expiration of the 31 day allowance.

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Inverters - Operating

LCO 3.8.7 Two inverters in each of four channels shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One inverter in one channel inoperable.	A.1	----------NOTE---------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems-Operating", with any AC Vital Bus deenergized. ---------- Restore inverter to OPERABLE status.	24 hours
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct inverter voltage, frequency, and alignment to required AC vital bus and from associated vital battery board and 480 V shutdown board.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.8 Inverters - Shutdown

LCO 3.8.8 Inverters shall be OPERABLE to support the onsite Class 1E AC vital bus electrical power distribution subsystem(s) required by LCO 3.8.10, "Distribution Systems - Shutdown."

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required inverter channels inoperable.	A.1	Declare affected required feature(s) inoperable.	Immediately
	OR		
	A.2.1	Suspend CORE ALTERATIONS.	Immediately
	AND		
	A.2.2	Suspend movement of irradiated fuel assemblies.	Immediately
	AND		
	A.2.3	Initiate action to suspend operations involving positive reactivity additions	Immediately
	AND		
	A.2.4	Initiate action to restore required inverters to OPERABLE status	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct inverter voltage, frequency, and alignments to required AC vital bus and from associated vital battery board and 480 V shutdown board.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems - Operating

LCO 3.8.9 Train A and Train B AC, four channels of vital DC, and four channels of AC vital bus electrical power distribution subsystems shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more AC electrical power distribution subsystems inoperable.	A.1	Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours <u>AND</u> 16 hours from discovery of failure to meet LCO
B. One or more AC vital buses in one channel inoperable.	B.1	Restore AC vital bus(es) to OPERABLE status.	2 hours <u>AND</u> 16 hours from discovery of failure to meet LCO
C. One or more vital DC electrical power distribution buses inoperable.	C.1	Restore DC electrical power distribution bus to OPERABLE status.	2 hours <u>AND</u> 16 hours from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours
E. Two trains with one or more inoperable distribution subsystems that result in a loss of safety function.	E.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and voltage to required AC, vital DC, and AC vital bus electrical power distribution subsystems.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.10 Distribution Systems - Shutdown

LCO 3.8.10 The necessary portion of AC, vital DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE to support equipment required to be OPERABLE.

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required AC, vital DC, or AC vital bus electrical power distribution subsystems inoperable.	A.1 Declare associated supported required feature(s) inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	A.2.3 Initiate action to suspend operations involving positive reactivity additions.	Immediately
	AND	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.4 Initiate actions to restore required AC, vital DC, and AC vital bus electrical power distribution subsystems to OPERABLE status.	Immediately
	AND	
	A.2.5 Declare associated required residual heat removal subsystem(s) inoperable and not in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.10.1	Verify correct breaker alignments and voltage to required AC, vital DC, and AC vital bus electrical power distribution subsystems.	7 days

3.9 REFUELING OPERATIONS

3.9.1 Boron Concentration

LCO 3.9.1 Boron concentrations of the Reactor Coolant System, the refueling canal, and the refueling cavity shall be maintained within the limit specified in the COLR.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Boron concentration not within limit.	A.1	Suspend CORE ALTERATIONS.	Immediately
	AND		
	A.2	Suspend positive reactivity additions.	Immediately
	AND		
	A.3	Initiate action to restore boron concentration to within limit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Verify boron concentration is within the limit specified in COLR.	72 hours

3.9 REFUELING OPERATIONS

3.9.2 Unborated Water Source Isolation Valves

LCO 3.9.2 Each valve used to isolate unborated water sources shall be secured in the closed position.

APPLICABILITY: MODE 6.

ACTIONS

----------NOTE----------
Separate Condition entry is allowed for each unborated water source isolation valve.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. ----------NOTE---------- Required Action A.3 must be completed whenever Condition A is entered. ---------- One or more valves not secured in closed position.	A.1	Suspend CORE ALTERATIONS.	Immediately
	AND		
	A.2	Initiate action to secure valve in closed position.	Immediately
	AND		
	A.3	Perform SR 3.9.1.1.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Verify each valve that isolates unborated water sources is secured in the closed position.	31 days

3.9 REFUELING OPERATIONS

3.9.3 Nuclear Instrumentation

LCO 3.9.3 Two source range neutron flux monitors shall be OPERABLE.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required source range neutron flux monitor inoperable.	A.1	Suspend CORE ALTERATIONS.	Immediately
	AND		
	A.2	Suspend positive reactivity additions.	Immediately
B. Two required source range neutron flux monitors inoperable.	B.1	Initiate action to restore one source range neutron flux monitor to OPERABLE status.	Immediately
	AND		
	B.2	Perform SR 3.9.1.1.	4 hours AND Once per 12 hours thereafter

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Perform CHANNEL CHECK.	12 hours
SR 3.9.3.2	----------NOTE---------- Neutron detectors are excluded from CHANNEL CALIBRATION. ---------- Perform CHANNEL CALIBRATION.	18 months

3.9 REFUELING OPERATIONS

3.9.4 RESERVED FOR FUTURE ADDITION

3.9 REFUELING OPERATIONS

3.9.5 Residual Heat Removal (RHR) and Coolant Circulation - High Water Level

LCO 3.9.5 One RHR loop shall be OPERABLE and in operation.

----------NOTE----------
The required RHR loop may be removed from operation for ≤ 1 hour per 8 hour period, provided no operations are permitted that would cause reduction of the Reactor Coolant System boron concentration.

APPLICABILITY: MODE 6 with the water level ≥ 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. RHR loop requirements not met.	A.1	Suspend operations involving a reduction in reactor coolant boron concentration.	Immediately
	AND		
	A.2	Suspend loading irradiated fuel assemblies in the core.	Immediately
	AND		
	A.3	Initiate action to satisfy RHR loop requirements.	Immediately
	AND		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.4	Close all containment penetrations providing direct access from containment atmosphere to outside atmosphere.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	Verify one RHR loop is in operation and circulating reactor coolant at a flow rate of ≥ 2500 gpm.	12 hours

3.9 REFUELING OPERATIONS

3.9.6 Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level

LCO 3.9.6 Two RHR loops shall be OPERABLE, and one RHR loop shall be in operation.

APPLICABILITY: MODE 6 with the water level < 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Less than the required number of RHR loops OPERABLE.	A.1	Initiate action to restore required RHR loops to OPERABLE status.	Immediately
	AND		
	A.2	Initiate action to establish ≥ 23 ft of water above the top of reactor vessel flange.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. No RHR loop in operation.	B.1	Suspend operations involving a reduction in reactor coolant boron concentration.	Immediately
	AND		
	B.2	Initiate action to restore one RHR loop to operation.	Immediately
	AND		
	B.3	Close all containment penetrations providing direct access from containment atmosphere to outside atmosphere.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.6.1	Verify one RHR loop is in operation and circulating reactor coolant at a flow rate of ≥ 2000 gpm.	12 hours
SR 3.9.6.2	Verify correct breaker alignment and indicated power available to the required RHR pump that is not in operation.	7 days

3.9 REFUELING OPERATIONS

3.9.7 Refueling Cavity Water Level

LCO 3.9.7 Refueling cavity water level shall be maintained ≥ 23 ft above the top of reactor vessel flange.

APPLICABILITY: During movement of irradiated fuel assemblies within containment.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Refueling cavity water level not within limit.	A.1	Suspend movement of irradiated fuel assemblies within containment.	Immediately
	AND		
	A.2	Initiate action to restore refueling cavity water level to within limit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.7.1	Verify refueling cavity water level is ≥ 23 ft above the top of reactor vessel flange.	24 hours

3.9 REFUELING OPERATIONS

3.9.8 RESERVED FOR FUTURE ADDITION

3.9 REFUELING OPERATIONS

3.9.9 Spent Fuel Pool Boron Concentration

LCO 3.9.9 Boron concentration of the spent fuel pool shall be ≥ 2000 ppm.

APPLICABILITY: During fuel movement in the flooded spent fuel pool.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Boron concentration not within limit.	A.1 Suspend fuel movement.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.9.1	Verify boron concentration in the spent fuel pool is ≥ 2000 ppm.	Prior to movement of fuel in the spent fuel pool AND 72 hours thereafter

3.9 REFUELING OPERATIONS

3.9.10 Decay Time

LCO 3.9.10 The reactor shall be subcritical for ≥ 100 hours.

APPLICABILITY: During movement of irradiated fuel assemblies within the containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor subcritical for < 100 hours.	A.1 Suspend all operations involving movement of irradiated fuel assemblies within the containment.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.10.1	Verify the reactor has been subcritical for ≥ 100 hours by confirming the date and time of subcriticality.	Prior to movement of irradiated fuel in the reactor vessel.

4.0 DESIGN FEATURES

4.1 Site

4.1.1 Site and Exclusion Area Boundaries

The site and exclusion area boundaries shall be as shown in Figure 4.1-1.

4.1.2 Low Population Zone (LPZ)

The LPZ shall be as shown in Figure 4.1-2 (within the 3-mile circle).

4.2 Reactor Core

4.2.1 Fuel Assemblies

The reactor shall contain 193 fuel assemblies. Each assembly shall consist of a matrix of Zirlo fuel rods with an initial composition of natural or slightly enriched uranium dioxide (UO_2) as fuel material. Limited substitutions of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in nonlimiting core regions.

4.2.2 Control Rod Assemblies

The reactor core shall contain 57 control rod assemblies. The control material shall be silver indium cadmium as approved by the NRC.

(continued)

4.0 DESIGN FEATURES (continued)

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks (shown in Figure 4.3-1) are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent (wt%);

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which, includes an allowance for uncertainties as described in Sections 4.3.2.7 and 9.1 of the FSAR;

c. Distances between fuel assemblies are a nominal 10.375 inch center-to-center spacing in the twenty-four flux trap rack modules.

d. Fuel assemblies with initial enrichments less than a maximum of 5 wt% U-235 enrichment (nominally 4.95 $\pm$ 0.05 wt% U-235) may be stored in the spent fuel racks in any one of four arrangements with specific limits as identified below:

1. Fuel assemblies may be stored in the racks in an all cell arrangement provided the burnup of each assembly is in the acceptable domain identified in Figure 4.3-3, depending upon the specified initial enrichment.

2. New and spent fuel assemblies may be stored in a checkerboard arrangement of 2 new and 2 spent assemblies, provided that each spent fuel assembly has accumulated a minimum burnup in the acceptable domain identified in Figure 4.3-4.

3. New fuel assemblies may be stored in 4-cell arrays with 1 of the 4 cells remaining empty of fuel (i.e. containing only water or water with up to 75 percent by volume of non-fuel bearing material).

(continued)

4.0 DESIGN FEATURES

4.3 Fuel Storage (continued)

4. New fuel assemblies with a minimum of 32 integral fuel burnable absorber (IFBA) rods may be stored without further restriction, provided the loading of ZrB_2 in the coating of each IFBA rod is minimum of 1.25x (1.9625mg/in).

A water cell is less reactive than any cell containing fuel and therefore a water cell may be used at any location in the loading arrangements. A water cell is defined as a cell containing water or non-fissile material with no more than 75 percent of the water displaced.

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

a. Fuel assemblies having a maximum enrichment of 5.0 weight percent U-235 and shall be maintained with the arrangement of 120 storage locations shown in Figure 4.3-2;

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

c. $k_{eff} \leq 0.98$ if moderated by aqueous foam, which includes an allowance for uncertainties as described in Section 9.1 of the FSAR; and

d. A nominal 21-inch center to center distance between fuel assemblies placed in the storage racks.

4.3.2 Drainage

The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below Elevation 747 feet - 1 1/2 inches.

4.3.3 Capacity

The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 1386 fuel assemblies in 24 flux trap rack modules.

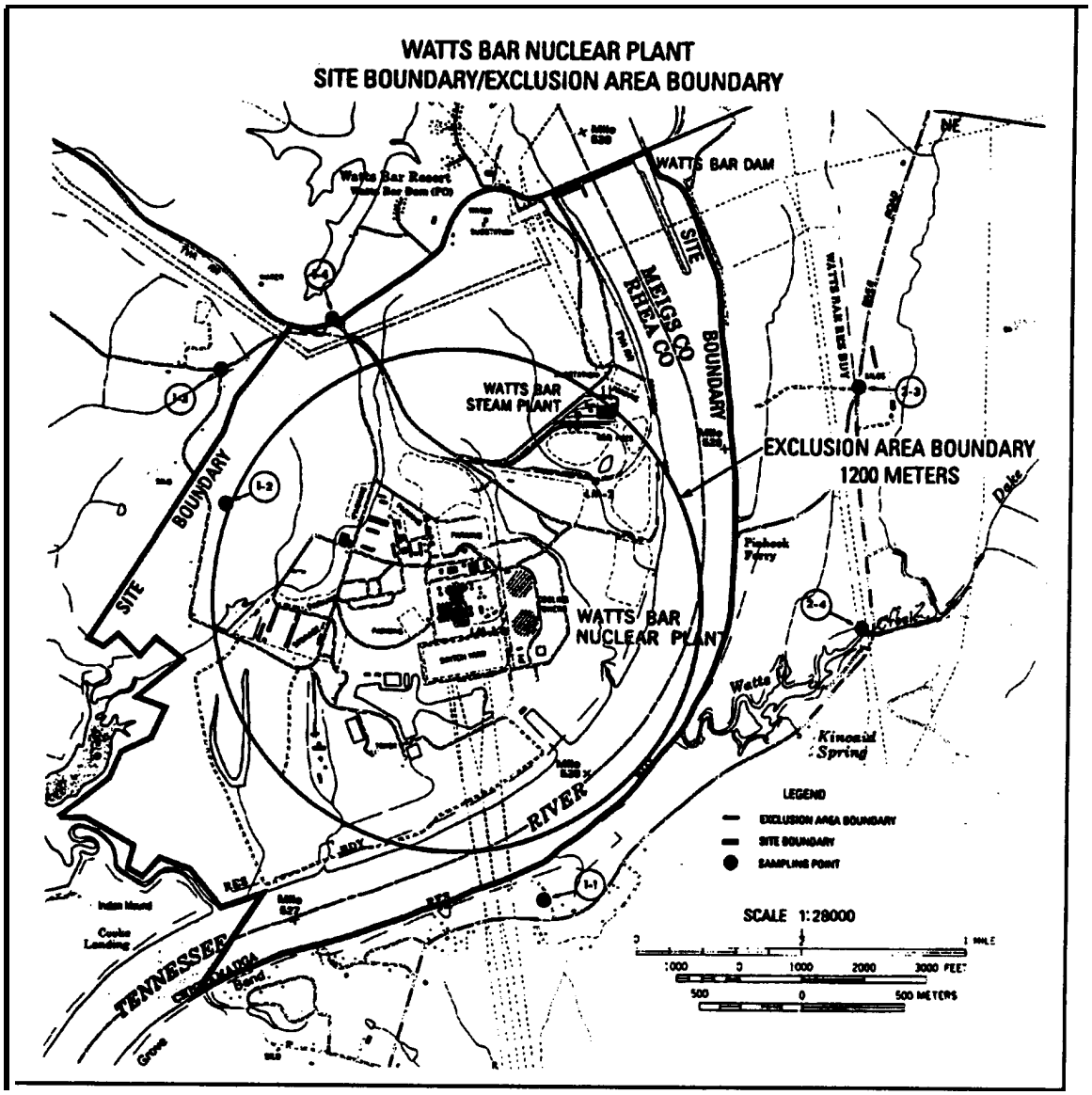


FIGURE 4.1-1 (PAGE 1 OF 1)
SITE AND EXCLUSION AREA BOUNDARIES

(continued)

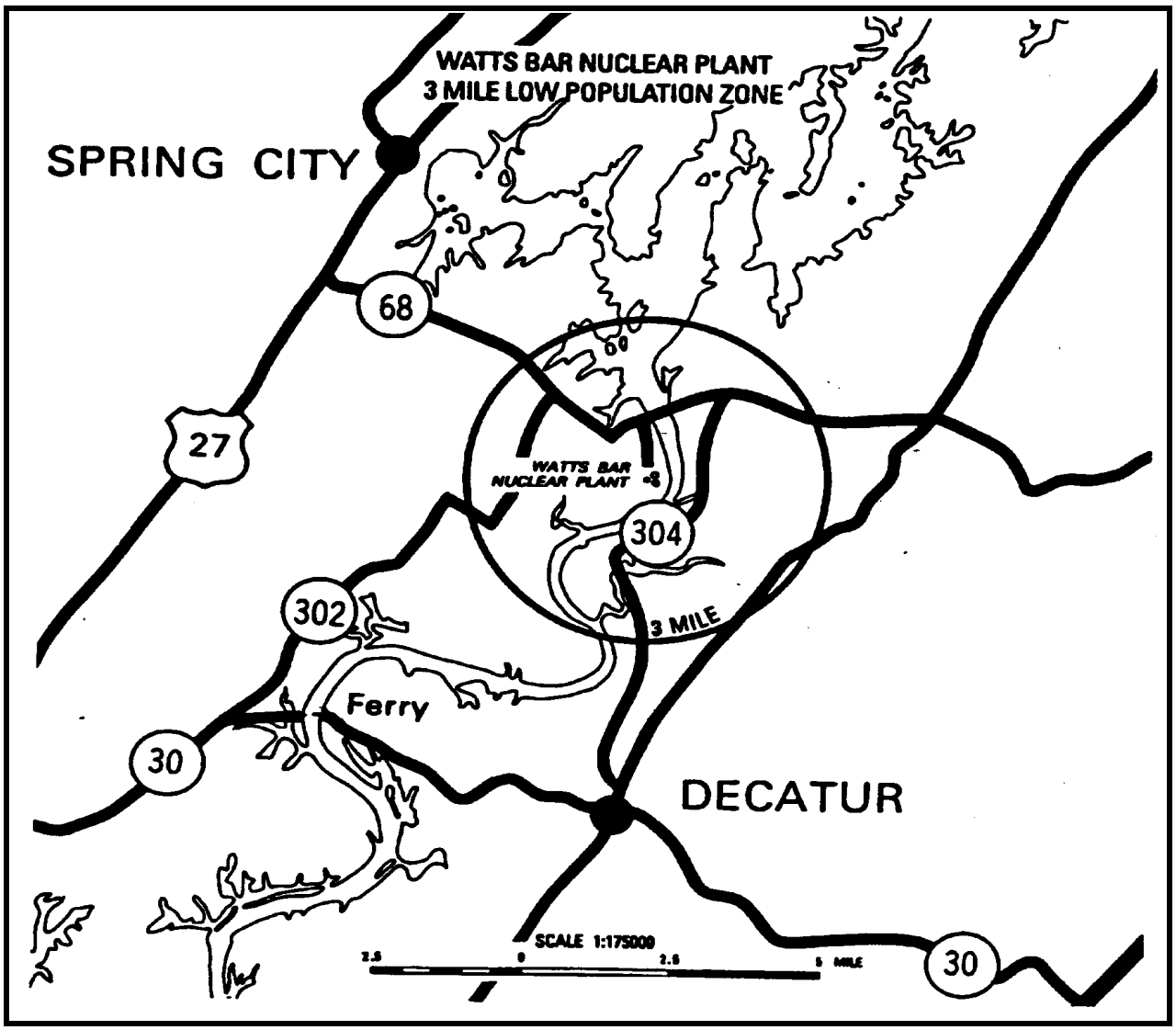


FIGURE 4.1-2 (PAGE 1 OF 1)
LOW POPULATION ZONE

(continued)

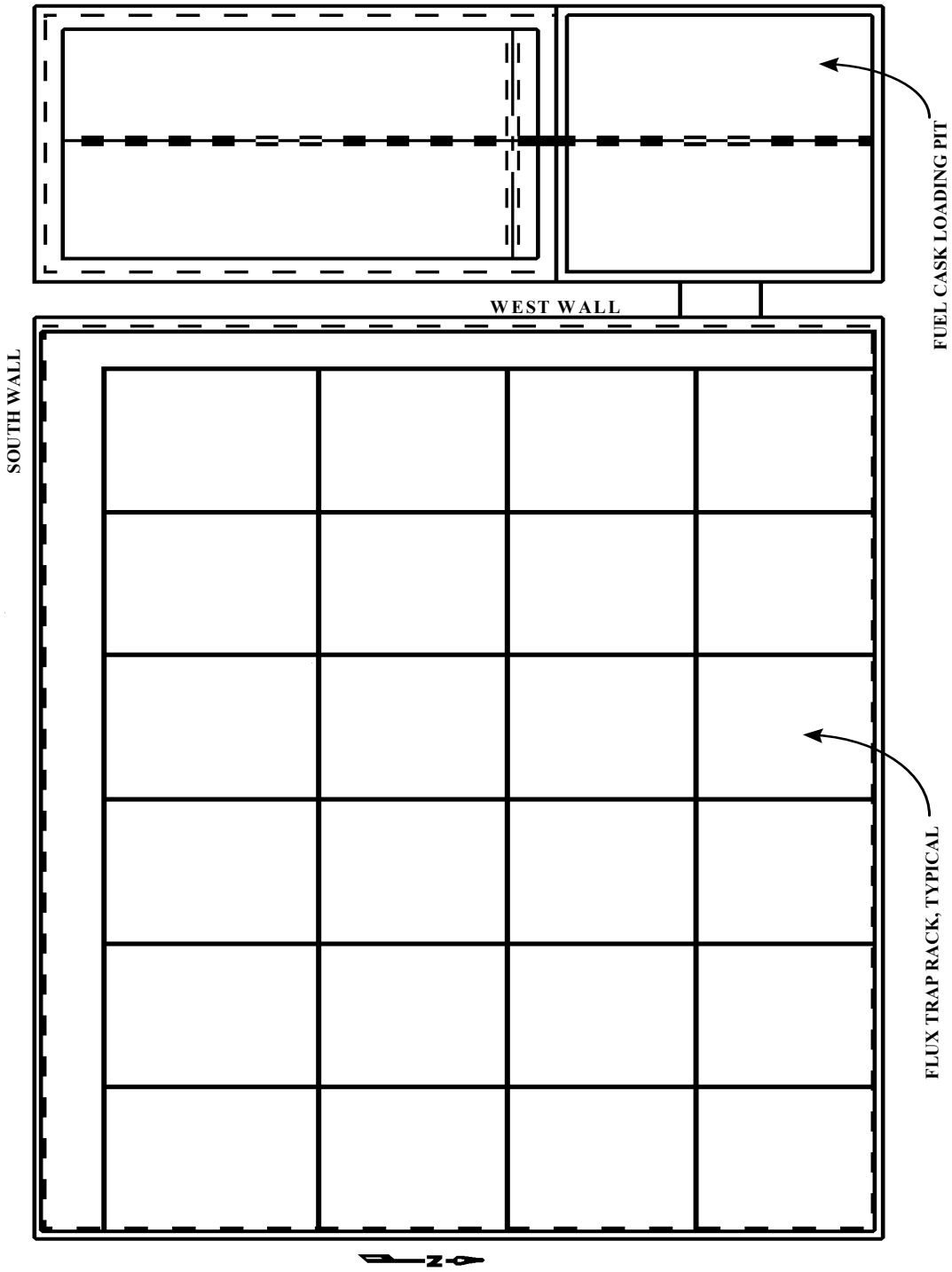


FIGURE 4.3-1
SPENT FUEL STORAGE RACKS

PLAN
SPENT FUEL POOL

(continued)

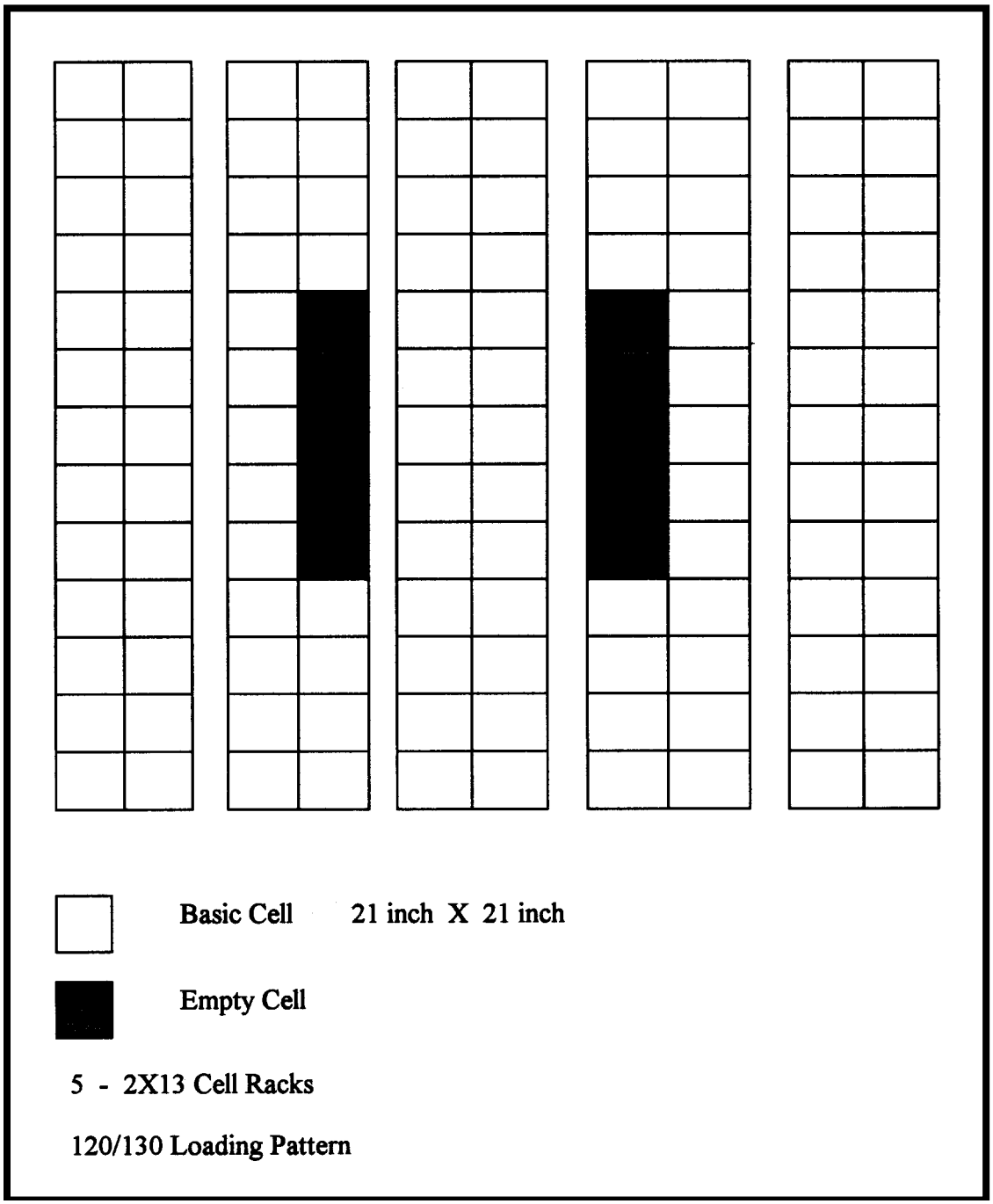


FIGURE 4.3-2
NEW FUEL STORAGE RACK LOADING PATTERN

(continued)

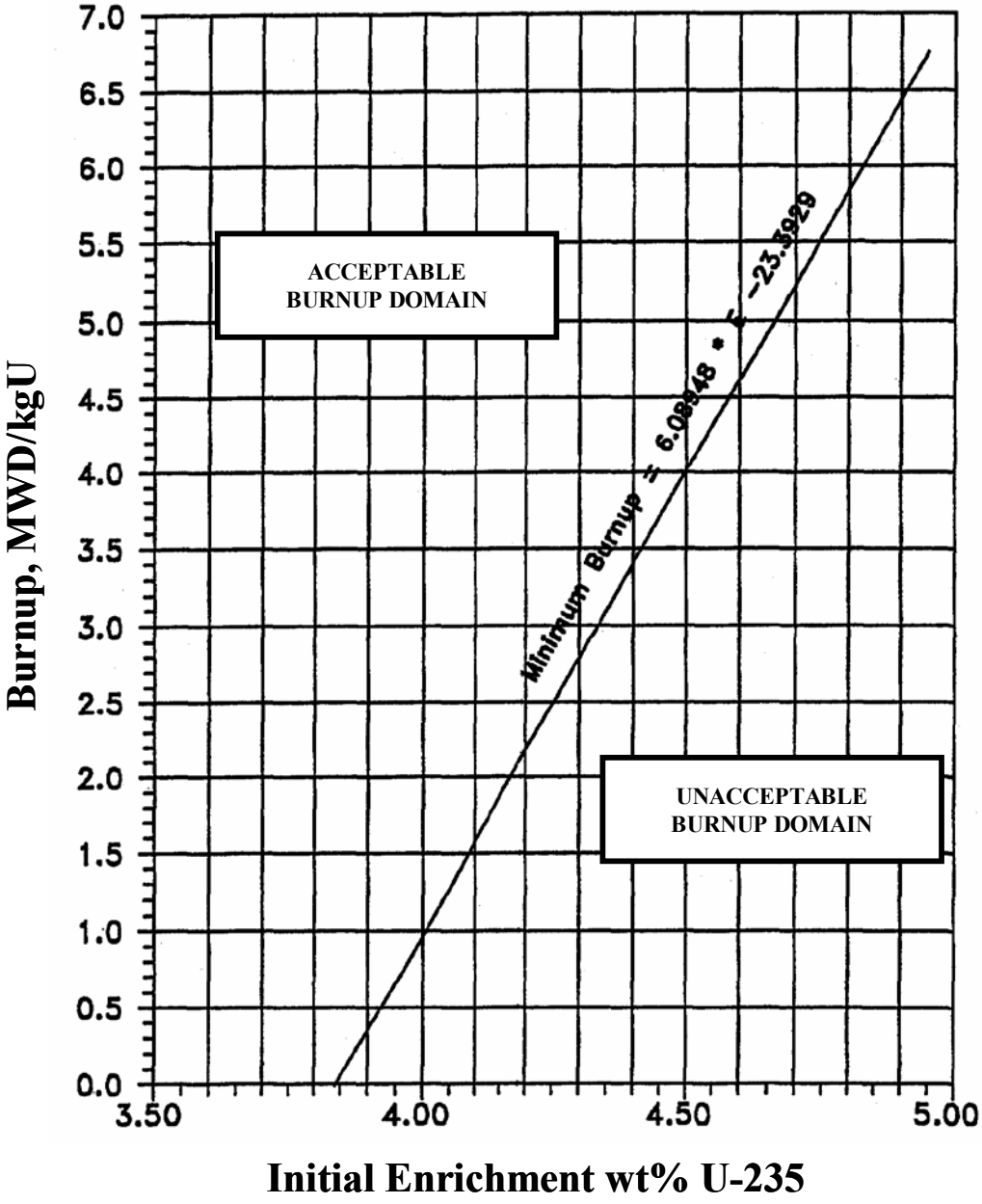


FIGURE 4.3-3
MINIMUM REQUIRED BURNUP FOR UNRESTRICTED STORAGE
OF FUEL OF VARIOUS INITIAL ENRICHMENTS

(continued)

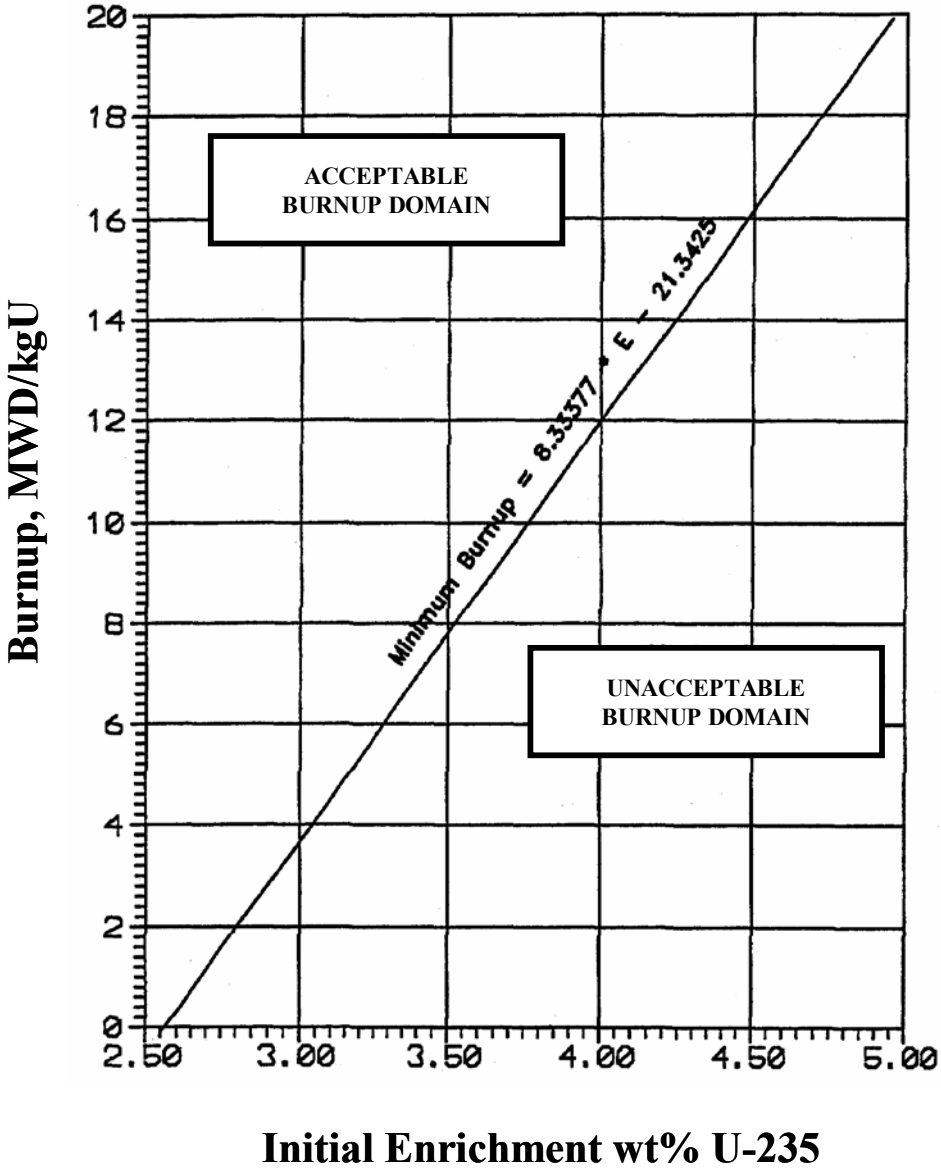


FIGURE 4.3-4
MINIMUM REQUIRED BURNUP FOR A CHECKERBOARD ARRANGEMENT OF 2 SPENT AND 2 NEW FUEL ASSEMBLIES OF 5 wt% U-235 ENRICHMENT (MAXIMUM)

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The Site Vice-President shall be responsible for overall activities of the site, while the Plant Manager shall be responsible for overall unit operation. The Site Vice-President and the Plant Manager shall delegate in writing the succession to this responsibility during his absence.

The Plant Manager or his designee shall approve, prior to implementation, each proposed test, experiment or modification to systems or equipment that affect nuclear safety.

5.1.2 The Shift Manager (SM) shall be responsible for the control room command function. During any absence of the SM from the control room while the unit is in MODE 1, 2, 3, or 4, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the SM from the control room while the unit is in MODE 5 or 6, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

Onsite and offsite organizations shall be established for unit operation and corporate management, respectively. The onsite and offsite organizations shall include the positions for activities affecting safety of the nuclear power plant.

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the Nuclear Power Organization Topical Report (TVA-NPOD 89-A);

b. The Plant Manager shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

c. The Site Vice-President shall have responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety; and

d. The individuals who train the operating staff, carry out radiological controls, 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 Organization (continued)

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 shall be assigned for each control room from which a reactor is being operated in MODES 1, 2, 3, or 4.

b. The shift crew composition may be less than the minimum requirements of 10 CFR 50.54(m)(2)(i) and Specifications 5.2.2.a and 5.2.2.f for a period of time not to exceed 2 hours in order to accommodate unexpected absences of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

c. A radiological controls technician shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

d. Reserved for Future Use

e. The Operations Superintendent shall have a valid SRO license on this unit.

f. An individual shall provide advisory technical support to the unit operations shift crew in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. This individual shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on shift (Generic Letter 86-04 dated 02/13/86).

5.0 ADMINISTRATIVE CONTROLS

5.3 Unit Staff Qualifications

5.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications for comparable positions, as specified in TVA Nuclear Quality Assurance Plan (TVA-NQA-PLN89-A).

5.3.2 For the purpose of 10 CFR 55.4, a licensed Senior Reactor Operator (SRO) and a licensed Reactor Operator (RO) are those individuals who, in addition to meeting the requirements of TS 5.3.1, perform the functions described in 10 CFR 50.54 (m).

5.0 ADMINISTRATIVE CONTROLS

5.4 Training

(removed from Technical Specifications)

5.0 ADMINISTRATIVE CONTROLS

5.5 Reviews and Audits

(removed from Technical Specifications)

5.0 ADMINISTRATIVE CONTROLS

5.6 Technical Specifications (TS) Bases Control Program

This Program provides a means for processing changes to the Bases of these Technical Specifications.

5.6.1 Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

5.6.2 Licensees may make changes to Bases without prior NRC approval provided the changes do not require either of the following:

a. A change in the TS incorporated in the license; or

b. A change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

5.6.3 The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

5.6.4 Proposed changes that meet the criteria of Specification 5.6.2 shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.0 ADMINISTRATIVE CONTROLS

5.7 Procedures, Programs, and Manuals

5.7.1 Procedures

5.7.1.1 Scope

Written procedures shall be established, implemented, and maintained covering the following activities:

a. The applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978;

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and NUREG-0737, Supplement 1 (Generic Letter 82-33);

c. Quality assurance for effluent and environmental monitoring;

d. Fire Protection Program implementation; and

e. All programs specified in Specification 5.7.2.

5.7.1.2 Reserved for Future Use

5.7.1.3 Reserved for Future Use

5.7 Procedures, Programs, and Manuals (continued)

5.7.2 Programs and Manuals

The following programs shall be established, implemented, and maintained.

5.7.2.1 Reserved for Future Use

5.7.2.2 Reserved for Future Use

5.7.2.3 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 Specifications 5.9.2 and 5.9.3.

Licensee initiated changes to the ODCM:

a. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

1. sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s),

2. a determination that the change(s) maintain the levels of radioactive effluent control required by 10 CFR 20.1302, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations;

b. Shall become effective after the approval of the Plant Manager; and

(continued)

5.7 Procedures, Programs, and Manuals

5.7.2.3 Offsite Dose Calculation Manual (ODCM) (continued)

c. 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. 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.

5.7.2.4 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 Containment Spray, Safety Injection, Residual Heat Removal, Chemical and Volume Control, Reactor Coolant System Sampling, and Waste Gas. The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at least once per 18 months.

The provisions of SR 3.0.2 are applicable.

5.7.2.5 Reserved for Future Use

5.7.2.6 Reserved for Future Use

5.7 Procedures, Programs, and Manuals (continued)

5.7.2.7 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the 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;

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to 10 times the concentration values in 10 CFR 20.1001-20.2402, Appendix B, Table 2, Column 2;

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

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 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. Determination of projected dose contributions from radioactive effluents in accordance with the methodology 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;

(continued)

5.7.2.7 Radioactive Effluent Controls Program (continued)

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents from the site to areas at or beyond the site boundary shall be in accordance with the following:

1. For noble gases: a dose rate ≤ 500 mrem/yr to the whole body and a dose rate ≤ 3000 mrem/yr to the skin, and

2. For iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives greater than 8 days: a dose rate ≤ 1500 mrem/yr to any organ.

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, iodine-133, tritium, and all radionuclides in particulate form with half-lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public, beyond the site boundary, due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Radioactive Effluent Controls Program surveillance frequency.

5.7.2.8 Reserved for Future Use

5.7.2.9 Component Cyclic or Transient Limit

This program provides controls to track the FSAR, Section 5.2.1.5, cyclic and transient occurrences to ensure that components are maintained within the design limits.

5.7 Procedures, Programs, and Manuals (continued)

5.7.2.10 Reactor Coolant Pump Flywheel Inspection Program

This program shall provide for the inspection of each reactor coolant pump flywheel per the recommendations of Regulation Position c.4.b of Regulatory Guide 1.14, Revision 1, August 1975.

In lieu of Position C.4.b(1) and C.4.b(2), a qualified in-place UT examination over the volume from the inner bore of the flywheel to the circle one-half of the outer radius or a surface examination (MT and/or PT) of exposed surfaces of the removed flywheels may be conducted at 20 year intervals.

5.7 Procedures, Programs, and Manuals (continued)

5.7.2.11 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components. The program shall include the following:

a. Testing frequencies applicable to the ASME Code for Operations and Maintenance of Nuclear Power Plants (ASME OM Code) and applicable Addenda as follows:

ASME OM Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies and other normal and accelerated Frequencies specified as 2 years or less in the Inservice Testing Program for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME OM Code shall be construed to supersede the requirements of any TS.

5.7 Procedures, Programs, and Manuals (continued)

5.7.2.12 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the "as found" condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The "as found" condition refers to the condition of the tubing during a SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged, to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cooldown), all anticipated transients included in the design specification and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

(continued)

5.7.2.12 Steam Generator (SG) Program (continued)

2. Accident induced leakage performance criterion: The primary-to-secondary accident induced leakage rate for any design basis accident, other than an SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 1 gpm per SG.

3. The operational leakage performance criterion is specified in LCO 3.4.13, "RCS Operational LEAKAGE."

c. Provisions for SG tube plugging criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. The number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube plugging criteria. The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what locations.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

(continued)

5.7.2.12 Steam Generator (SG) Program (continued)

2. After the first refueling outage following SG installation, inspect each SG at least every 24 effective full power months or at least every refueling outage (whichever results in more frequent inspections). In addition, inspect 100% of the tubes at sequential periods of 60 effective full power months beginning after the first refueling outage inspection following SG installation. Each 60 effective full power month inspection period may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period.

3. If crack indications are found in any SG tube, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary-to-secondary LEAKAGE.

5.7 Procedures, Programs, and Manuals (continued)

5.7.2.13 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation and low pressure turbine disc stress corrosion cracking. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in leakage;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.7 Procedures, Programs, and Manuals (continued)

5.7.2.14 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of Engineered Safety Feature (ESF) filter ventilation systems at the frequencies specified in accordance with Regulatory Guide 1.52, Revision 2; ASME N510-1989, and the exceptions noted for each ESF system in Tables 6.5-1, 6.5-2, and 6.5-4 of the FSAR.

a. Demonstrate for each of the ESF systems that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass within acceptance criterion when tested in accordance with Regulatory Guide 1.52, Revision 2, the exceptions noted for each ESF system in Tables 6.5-1, 6.5-2, and 6.5-4 of the FSAR, and ASME N510-1989 at the system flowrate specified below.

ESF VENTILATION SYSTEM	ACCEPTANCE CRITERIA	FLOW RATE
Emergency Gas Treatment	< 0.05%	4,000 cfm ±10%
Auxiliary Building Gas Treatment	< 0.05%	9,000 cfm ± 10%
Control Room Emergency	< 1.00%	4,000 cfm ± 10%

(continued)

5.7.2.14 Ventilation Filter Testing Program (VFTP) (continued)

b. Demonstrate for each of the ESF systems that an inplace test of the charcoal adsorber shows a penetration and system bypass within acceptance criterion when tested in accordance with Regulatory Guide 1.52, Revision 2, the exceptions noted for each ESF system in Tables 6.5-1, 6.5-2, and 6.5-4 of the FSAR, and ASME N510-1989 at the system flowrate specified below.

ESF VENTILATION SYSTEM	ACCEPTANCE CRITERIA	FLOW RATE
Emergency Gas Treatment	< 0.05%	4,000 cfm ± 10%
Auxiliary Building Gas Treatment	< 0.05%	9,000 cfm ± 10%
Control Room Emergency	< 1.00%	4,000 cfm ± 10%

(continued)

5.7.2.14 Ventilation Filter Testing Program (VFTP) (continued)

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, and the exceptions noted for each ESF system in Tables 6.5-1, 6.5-2, and 6.5-4 of the FSAR, 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 specified below.

ESF VENTILATION SYSTEM	METHYL IODIDE PENETRATION	RELATIVE HUMIDITY
Emergency Gas Treatment	< 0.175%	70%
Auxiliary Building Gas Treatment	< 0.175%	70%
Control Room Emergency	< 1.0%	70%

d. Demonstrate for each of the ESF systems that the pressure drop across the entire filtration unit is less than the value specified below when tested in accordance with Regulatory Guide 1.52, Revision 2, the exceptions noted for each ESF system in Tables 6.5-1, 6.5-2, and 6.5-4 of the FSAR, and ASME N510-1989 at the system flowrate specified below.

ESF VENTILATION SYSTEM	PRESSURE DROP	FLOW RATE
Emergency Gas Treatment	< 7.6 inches water	4,000 cfm ± 10%
Auxiliary Building Gas Treatment	< 7.6 inches water	9,000 cfm ± 10%
Control Room Emergency	< 3.5 inches water	4,000 cfm ± 10%

(continued)

5.7.2.14 Ventilation Filter Testing Program (VFTP) (continued)

e. Demonstrate that the heaters for each of the ESF systems dissipate the value specified below when tested in accordance with ASME N510-1989.

ESF VENTILATION SYSTEM	AMOUNT OF HEAT
Emergency Gas Treatment	20 ± 2.0 kW
Auxiliary Building Gas Treatment	50 ± 5.0 kW

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.7.2.15 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Waste Gas Holdup System, the quantity of radioactivity contained in gas storage tanks 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.”

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Waste Gas Holdup System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., the system is not designed to withstand a hydrogen explosion);

(continued)

5.7.2.15 Explosive Gas and Storage Tank Radioactivity Monitoring Program (continued)

b. A surveillance program to ensure that the quantity of radioactivity contained in each gas storage tank 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

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is less than the amount that would result in concentrations less than the limits of 10 CFR 20.1302(b)(2)(i), at the nearest potable water supply and the nearest surface water supply in an unrestricted area, in the event of an uncontrolled release of the tanks' contents.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

5.7.2.16 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to the 7 day storage tanks by determining that the fuel oil has:

1. an API gravity or an absolute specific gravity within limits,

2. a flash point and kinematics viscosity within limits for ASTM 2D fuel oil, and

3. a clear and bright appearance with proper color;

(continued)

5.7 Procedures, Programs, and Manuals

5.7.2.16 Diesel Fuel Oil Testing Program (continued)

b. Other properties for ASTM 2D fuel oil are within limits within 31 days following sampling and addition to the 7 day storage tanks; and

c. Total particulate concentration of the fuel oil in each of the four interconnected tanks which constitute a 7 day storage tank is $\leq$ 10 mg/l when tested every 31 days in accordance with ASTM D-2276, Method A-2 or A-3.

5.7.2.17 (removed from Technical Specifications)

5.7.2.18 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

(continued)

5.7.2.18 Safety Function Determination Program (SFDP) (continued)

A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

5.7.2.19 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50 Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide (RG) 1.163, “Performance-Based Containment Leak-Test Program,” dated September 1995.

For containment leakage rate testing purposes, a value of 15.0 psig, which is equivalent to the maximum allowable internal containment pressure, is utilized for P_a to bound the peak calculated containment internal pressure for the design basis loss of coolant accident.

The maximum allowable containment leakage rate, L_a, at P_a, is 0.25% of the primary containment air weight per day.

(continued)

5.7.2.19 Containment Leakage Rate Testing Program (continued)

Leakage rate acceptance criteria are:

a. Containment overall leakage rate acceptance criterion is $\leq$ 1.0 L_a. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are < 0.60 L_a for the combined Type B and Type C tests, and $\leq$ 0.75 L_a for Type A tests.

b. Air lock testing acceptance criteria are:

   1. Overall air lock leakage rate is $\leq$ 0.05 L_a when tested at $\geq P_a$.

   2. For each door, leakage rate is $\leq$ 0.01 L_a when pressurized to $\geq$ 6 psig.

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Containment Leakage Rate Testing Program.

The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

5.7.2.20 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Ventilation System (CREVS), CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event, hazardous chemical release, or a smoke challenge. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of the applicable regulatory requirement (i.e., 5 rem Total Effective Dose Equivalent (TEDE) for a fuel handling accident or 5 rem whole body or its equivalent to any part of the body) for the duration of the accident. The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

(continued)

5.7 Procedures, Programs, and Manuals

5.7.2.20 Control Room Envelope Habitability Program (continued)

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

d. Measurement, at designated locations, of the CRE pressure relative to all external areas adjacent to the CRE boundary during the pressurization mode of operation by one train of the CREVS, operating at the flow rate defined in the Ventilation Filter Testing Program (VFTP), at a Frequency of 18 months on a STAGGERED TEST BASIS. The results shall be trended and used as part of the 18 month assessment of the CRE boundary.

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

5.0 ADMINISTRATIVE CONTROLS

5.8 Safety Function Determination Program (SFDP)

(moved to 5.7.2.18)

5.0 ADMINISTRATIVE CONTROLS

5.9 Reporting Requirements

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

5.9.1 Reserved for Future Use

5.9.2 Annual Radiological Environmental Operating Report

----------NOTE----------
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

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

The Annual Radiological Environmental Operating Report shall include the results of analyses of all radiological environmental samples and of all environmental radiation measurements taken during the period pursuant to the locations specified in the table and figures in the ODCM, as well as summarized and tabulated results of these analyses and measurements in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting and explaining the reasons for the missing results. The missing data shall be submitted in a supplementary report as soon as possible.

5.9 Reporting Requirements (continued)

5.9.3 Radioactive Effluent Release Report

----------NOTE----------
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station; however, for units with separate radwaste systems, the submittal shall specify the releases of radioactive material from each unit.

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

5.9.4 Reserved for Future Use

5.9.5 CORE OPERATING LIMITS REPORT (COLR)

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

LCO 3.1.4	Moderator Temperature Coefficient
LCO 3.1.6	Shutdown Bank Insertion Limits
LCO 3.1.7	Control Bank Insertion Limits
LCO 3.2.1	Heat Flux Hot Channel Factor
LCO 3.2.2	Nuclear Enthalpy Rise Hot Channel Factor
LCO 3.2.3	Axial Flux Difference
LCO 3.9.1	Boron Concentration

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:

(continued)

5.9 Reporting Requirements

5.9.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

1. WCAP-9272-P-A, WESTINGHOUSE RELOAD SAFETY EVALUATION METHODOLOGY," July 1985 (W Proprietary). (Methodology for Specifications 3.1.4 - Moderator Temperature Coefficient, 3.1.6 - Shutdown Bank Insertion Limit, 3.1.7 - Control Bank Insertion Limits, 3.2.1 - Heat Flux Hot Channel Factor, 3.2.2 - Nuclear Enthalpy Rise Hot Channel Factor, 3.2.3 - Axial Flux Difference, and 3.9.1 - Boron Concentration).

2a. WCAP-16009-P-A, "Realistic Large-Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method (ASTRUM)," January 2005 (W Proprietary).(Methodology for Specification 3.2.1 - Heat Flux Hot Channel Factor, and 3.2.2 - Nuclear Enthalpy Rise Hot Channel Factor).

2b. WCAP-10054-P-A, "Small Break ECCS Evaluation Model Using NOTRUMP Code," August 1985. Addendum 2, Rev. 1: "Addendum to the Westinghouse Small Break ECCS Evaluation Model using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," July 1997. (W Proprietary). (Methodology for Specifications 3.2.1 - Heat Flux Hot Channel Factor, and 3.2.2 - Nuclear Enthalpy Rise Hot Channel Factor).

3. WCAP-10216-P-A, Revision 1A, "RELAXATION OF CONSTANT AXIAL OFFSET CONTROL F(Q) SURVEILLANCE TECHNICAL SPECIFICATION," February 1994 (W Proprietary). (Methodology for Specifications 3.2.1 - Heat Flux Hot Channel Factor (W(Z) Surveillance Requirements For F(Q) Methodology) and 3.2.3 - Axial Flux Difference (Relaxed Axial Offset Control).)

4. WCAP-12610-P-A, "VANTAGE + FUEL ASSEMBLY REFERENCE CORE REPORT," April 1995. (W Proprietary). (Methodology for Specification 3.2.1 - Heat Flux Hot Channel Factor).

(continued)

5.9 Reporting Requirements

5.9.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

5. WCAP-15088-P, Rev. 1, "Safety Evaluation Supporting A More Negative EOL Moderator Temperature Coefficient Technical Specification for the Watts Bar Nuclear Plant," July 1999, (W Proprietary), as approved by the NRC staff's Safety Evaluation accompanying the issuance of Amendment No. 20 (Methodology for Specification 3.1.4 - Moderator Temperature Coefficient.).

6. WCAP-11397-P-A, "Revised Thermal Design Procedure," April 1989. (Methodology for Specification 3.2.2 - Nuclear Enthalpy Rise Hot Channel Factor).

7. WCAP-15025-P-A, "Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17 x 17 Rod Bundles with Modified LPD Mixing Vane Grids," April 1999. (Methodology for Specification 3.2.2 - Nuclear Enthalpy Rise Hot Channel Factor).

8. WCAP-14565-P-A, "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," October 1999. (Methodology for Specification 3.2.2 - Nuclear Enthalpy Rise Hot Channel Factor).

9a. WCAP-12472-P-A, "BEACON™ CORE MONITORING AND OPERATIONS SUPPORT SYSTEM," August 1994, (W Proprietary). (Methodology for Specification 3.2.1 – Heat Flux Hot Channel Factor, and 3.2.2 – Nuclear Enthalpy Rise Hot Channel Factor).

9b. WCAP-12472-P-A, Addendum 1-A, "BEACON™ MONITORING AND OPERATIONS SUPPORT SYSTEM," January 2000, (W Proprietary). (Methodology for Specification 3.2.1 – Heat Flux Hot Channel Factor, and 3.2.2 – Nuclear Enthalpy Rise Hot Channel Factor).

9c. WCAP-12472-P-A, Addendum 2-A, "BEACON™ MONITORING AND OPERATIONS SUPPORT SYSTEM (WCAP-12472-P-A) Addendum 2," April 2002, (W Proprietary) (Methodology for Specification 3.2.1 – Heat Flux Hot Channel Factor, and 3.2.2 – Nuclear Enthalpy Rise Hot Channel Factor).

9d. WCAP-12472-P-A, Addendum 4, "BEACON™ CORE MONITORING AND OPERATIONS SUPPORT SYSTEM, Addendum 4," September 2012, (W Proprietary) (Methodology for Specification 3.2.1 – Heat Flux Hot Channel Factor, and 3.2.2 – Nuclear Enthalpy Rise Hot Channel Factor).

(continued)

5.9 Reporting Requirements

5.9.5 CORE OPERATING LIMTS REPORT (COLR) (continued)

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.

5.9 Reporting Requirements (continued)

5.9.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heatup, cooldown, low temperature operation (power operated relief valve lift settings required to support the Cold Overpressure Mitigation System (COMS) and the COMS arming temperature), criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

LCO 3.4.3 RCS Pressure and Temperature (P/T) Limits
LCO 3.4.12 Cold Overpressure Mitigation System (COMS)

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

1. WCAP-14040-A, Rev. 4 “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves.”

2. The PTLR will contain the complete identification for each of the TS reference Topical Reports used to prepare the PTLR (i.e., report number, title, revision, date, and any supplements).

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

5.9 Reporting Requirements (continued)

5.9.7 DG Failures Report

If an individual diesel generator (DG) experiences four or more valid failures in the last 25 demands, these failures and any nonvalid failures experienced by that DG in that time period shall be reported within 30 days. Reports on DG failures shall include the information recommended in Regulatory Guide 1.9, Revision 3, Regulatory Position C.4, or existing Regulatory Guide 1.108 reporting requirement.

5.9.8 PAMS Report

When a Report is required by Condition B or F of LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.9.9 Steam Generator Tube Inspection Report

A report shall be submitted within 180 days after the initial entry into MODE 4 following completion of an inspection performed in accordance with the Specification 5.7.2.12, Steam Generator (SG) Program. The report shall include:

a. The scope of inspections performed on each SG,

b. Degradation mechanisms found,

c. Nondestructive examination techniques utilized for each degradation mechanism,

d. Location, orientation (if linear), and measured sizes (if available) of service induced indications,

e. Number of tubes plugged during the inspection outage for each degradation mechanism,

f. The number and percentage of tubes plugged to date, and the effective plugging percentage in each SG,

g. The results of condition monitoring, including the results of tube pulls and in-situ testing.

5.0 ADMINISTRATIVE CONTROLS

5.10 Record Retention

(removed from Technical Specifications)

5.0 ADMINISTRATIVE CONTROLS

5.11 High Radiation Area

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

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

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

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

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

d. Each individual entering such an area shall possess:

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

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

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

(continued)

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

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

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

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

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

High Radiation Area (continued)

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

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

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

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

b. Access to, and activities in, each 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 otherwise following plant radiation protection procedures for entry to, exit from, and work in such areas.

d. Each individual entering such an area shall possess:

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

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

(continued)

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

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

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

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

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

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

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

ENCLOSURE 3

WBN Unit 2 Technical Specifications Bases

Tennessee Valley Authority

Watts Bar Nuclear Plant Unit 2

Technical Specifications Bases

(continued)

(continued)

LIST OF TABLES

LIST OF FIGURES

LIST OF ACRONYMS

ACRONYM	TITLE
ABGTS	Auxiliary Building Gas Treatment System
ACRP	Auxiliary Control Room Panel
AFD	Axial Flux Difference
AFW	Auxiliary Feedwater System
ARFS	Air Return Fan System
ARO	All Rods Out
ARV	Atmospheric Relief Valve
ASME	American Society of Mechanical Engineers
BOC	Beginning of Cycle
CAOC	Constant Axial Offset Control
CCS	Component Cooling Water System
CFR	Code of Federal Regulations
COLR	Core Operating Limits Report
CREVS	Control Room Emergency Ventilation System
CSS	Containment Spray System
CST	Condensate Storage Tank
DNB	Departure from Nucleate Boiling
ECCS	Emergency Core Cooling System
EFPD	Effective Full-Power Days
EGTS	Emergency Gas Treatment System
EOC	End of Cycle

(continued)

LIST OF ACRONYMS

ACRONYM	TITLE
ERCW	Essential Raw Cooling Water
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Features Actuation System
HEPA	High Efficiency Particulate Air
HVAC	Heating, Ventilating, and Air-Conditioning
LCO	Limiting Condition For Operation
MFIV	Main Feedwater Isolation Valve
MFRV	Main Feedwater Regulation Valve
MSIV	Main Steam Line Isolation Valve
MSSV	Main Steam Safety Valve
MTC	Moderator Temperature Coefficient
NMS	Neutron Monitoring System
ODCM	Offsite Dose Calculation Manual
PCP	Process Control Program
PIV	Pressure Isolation Valve
PORV	Power-Operated Relief Valve
PTLR	Pressure and Temperature Limits Report
QPTR	Quadrant Power Tilt Ratio
RAOC	Relaxed Axial Offset Control
RCCA	Rod Cluster Control Assembly
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System

(continued)

LIST OF ACRONYMS

ACRONYM	TITLE
RHR	Residual Heat Removal
RTP	Rated Thermal Power
RTS	Reactor Trip System
RWST	Refueling Water Storage Tank
SG	Steam Generator
SI	Safety Injection
SL	Safety Limit
SR	Surveillance Requirement
UHS	Ultimate Heat Sink

TECHNICAL SPECIFICATIONS BASES

LIST OF EFFECTIVE PAGES

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
i	0	B 3.0-9	0
ii	0	B 3.0-10	0
iii	0	B 3.0-11	0
iv	0	B 3.0-12	0
v	0	B 3.0-13	0
vi	0	B 3.0-14	0
vii	0	B 3.0-15	0
viii	0	B 3.0-16	0
ix	0	B 3.0-17	0
x	0	B 3.0-18	0
xi	0	B 3.1-1	0
xii	0	B 3.1-2	0
xiii	0	B 3.1-3	0
xiv	0	B 3.1-4	0
xiv	0	B 3.1-5	0
xv	0	B 3.1-6	0
xvi	0	B 3.1-7	0
xvii	0	B 3.1-8	0
xviii	0	B 3.1-9	0
xix	0	B 3.1-10	0
B 2.0-1	0	B 3.1-11	0
B 2.0-2	0	B 3.1-12	0
B 2.0-3	0	B 3.1-13	0
B 2.0-4	0	B 3.1-14	0
B 2.0-5	0	B 3.1-15	0
B 2.0-6	0	B 3.1-16	0
B 2.0-7	0	B 3.1-17	0
B 2.0-8	0	B 3.1-18	0
B 2.0-9	0	B 3.1-19	0
B 2.0-10	0	B 3.1-20	0
B 3.0-1	0	B 3.1-21	0
B 3.0-2	0	B 3.1-22	0
B 3.0-3	0	B 3.1-23	0
B 3.0-4	0	B 3.1-24	0
B 3.0-5	0	B 3.1-25	0
B 3.0-6	0	B 3.1-26	0
B 3.0-7	0	B 3.1-27	0
B 3.0-8	0	B 3.1-28	0

LIST OF EFFECTIVE PAGES

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
B 3.1-29	0	B 3.1-67	0
B 3.1-30	0	B 3.1-68	0
B 3.1-31	0	B 3.1-69	0
B 3.1-32	0	B 3.1-70	0
B 3.1-33	0	B 3.2-1	0
B 3.1-34	0	B 3.2-2	0
B 3.1-35	0	B 3.2-3	0
B 3.1-36	0	B 3.2-4	0
B 3.1-37	0	B 3.2-5	0
B 3.1-38	0	B 3.2-6	0
B 3.1-39	0	B 3.2-7	0
B 3.1-40	0	B 3.2-8	0
B 3.1-41	0	B 3.2-9	0
B 3.1-42	0	B 3.2-10	0
B 3.1-43	0	B 3.2-11	0
B 3.1-44	0	B 3.2-12	0
B 3.1-45	0	B 3.2-13	0
B 3.1-46	0	B 3.2-14	0
B 3.1-47	0	B 3.2-15	0
B 3.1-48	0	B 3.2-16	0
B 3.1-49	0	B 3.2-17	0
B 3.1-50	0	B 3.2-18	0
B 3.1-51	0	B 3.2-19	0
B 3.1-52	0	B 3.2-20	0
B 3.1-53	0	B 3.2-21	0
B 3.1-54	0	B 3.2-22	0
B 3.1-55	0	B 3.2-23	0
B 3.1-56	0	B 3.2-24	0
B 3.1-57	0	B 3.2-25	0
B 3.1-58	0	B 3.2-26	0
B 3.1-59	0	B 3.2-27	0
B 3.1-60	0	B 3.2-28	0
B 3.1-61	0	B 3.2-29	0
B 3.1-62	0	B 3.2-30	0
B 3.1-63	0	B 3.2-31	0
B 3.1-64	0	B 3.3-1	0
B 3.1-65	0	B 3.3-2	0
B 3.1-66	0	B 3.3-3	0

LIST OF EFFECTIVE PAGES

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
B 3.3-4	0	B 3.3-42	0
B 3.3-5	0	B 3.3-43	0
B 3.3-6	0	B 3.3-44	0
B 3.3-7	0	B 3.3-45	0
B 3.3-8	0	B 3.3-46	0
B 3.3-9	0	B 3.3-47	0
B 3.3-10	0	B 3.3-48	0
B 3.3-11	0	B 3.3-49	0
B 3.3-12	0	B 3.3-50	0
B 3.3-13	0	B 3.3-51	0
B 3.3-14	0	B 3.3-52	0
B 3.3-15	0	B 3.3-53	0
B 3.3-16	0	B 3.3-54	0
B 3.3-17	0	B 3.3-55	0
B 3.3-18	0	B 3.3-56	0
B 3.3-19	0	B 3.3-57	0
B 3.3-20	0	B 3.3-58	0
B 3.3-21	0	B 3.3-59	0
B 3.3-22	0	B 3.3-60	0
B 3.3-23	0	B 3.3-61	0
B 3.3-24	0	B 3.3-62	0
B 3.3-25	0	B 3.3-63	0
B 3.3-26	0	B 3.3-64	0
B 3.3-27	0	B 3.3-65	0
B 3.3-28	0	B 3.3-66	0
B 3.3-29	0	B 3.3-67	0
B 3.3-30	0	B 3.3-68	0
B 3.3-31	0	B 3.3-69	0
B 3.3-32	0	B 3.3-70	0
B 3.3-33	0	B 3.3-71	0
B 3.3-34	0	B 3.3-72	0
B 3.3-35	0	B 3.3-73	0
B 3.3-36	0	B 3.3-74	0
B 3.3-37	0	B 3.3-75	0
B 3.3-38	0	B 3.3-76	0
B 3.3-39	0	B 3.3-77	0
B 3.3-40	0	B 3.3-78	0
B 3.3-41	0	B 3.3-79	0

LIST OF EFFECTIVE PAGES

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
B 3.3-80	0	B 3.3-118	0
B 3.3-81	0	B 3.3-119	0
B 3.3-82	0	B 3.3-120	0
B 3.3-83	0	B 3.3-121	0
B 3.3-84	0	B 3.3-122	0
B 3.3-85	0	B 3.3-123	0
B 3.3-86	0	B 3.3-124	0
B 3.3-87	0	B 3.3-125	0
B 3.3-88	0	B 3.3-126	0
B 3.3-89	0	B 3.3-127	0
B 3.3-90	0	B 3.3-128	0
B 3.3-91	0	B 3.3-129	0
B 3.3-92	0	B 3.3-130	0
B 3.3-93	0	B 3.3-131	0
B 3.3-94	0	B 3.3-132	0
B 3.3-95	0	B 3.3-133	0
B 3.3-96	0	B 3.3-134	0
B 3.3-97	0	B 3.3-135	0
B 3.3-98	0	B 3.3-136	0
B 3.3-99	0	B 3.3-137	0
B 3.3-100	0	B 3.3-138	0
B 3.3-101	0	B 3.3-139	0
B 3.3-102	0	B 3.3-140	0
B 3.3-103	0	B 3.3-141	0
B 3.3-104	0	B 3.3-142	0
B 3.3-105	0	B 3.3-143	0
B 3.3-106	0	B 3.3-144	0
B 3.3-107	0	B 3.3-145	0
B 3.3-108	0	B 3.3-146	0
B 3.3-109	0	B 3.3-147	0
B 3.3-110	0	B 3.3-148	0
B 3.3-111	0	B 3.3-149	0
B 3.3-112	0	B 3.3-150	0
B 3.3-113	0	B 3.3-151	0
B 3.3-114	0	B 3.3-152	0
B 3.3-115	0	B 3.3-153	0
B 3.3-116	0	B 3.3-154	0
B 3.3-117	0	B 3.3-155	0

LIST OF EFFECTIVE PAGES

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
B 3.3-156	0	B 3.4-26	0
B 3.3-157	0	B 3.4-27	0
B 3.3-158	0	B 3.4-28	0
B 3.3-159	0	B 3.4-29	0
B 3.3-160	0	B 3.4-30	0
B 3.3-161	0	B 3.4-31	0
B 3.3-162	0	B 3.4-32	0
B 3.3-163	0	B 3.4-33	0
B 3.3-164	0	B 3.4-34	0
B 3.3-165	0	B 3.4-35	0
B 3.3-166	0	B 3.4-36	0
B 3.3-167	0	B 3.4-37	0
B 3.3-168	0	B 3.4-38	0
B 3.4-1	0	B 3.4-39	0
B 3.4-2	0	B 3.4-40	0
B 3.4-3	0	B 3.4-41	0
B 3.4-4	0	B 3.4-42	0
B 3.4-5	0	B 3.4-43	0
B 3.4-6	0	B 3.4-44	0
B 3.4-7	0	B 3.4-45	0
B 3.4-8	0	B 3.4-46	0
B 3.4-9	0	B 3.4-47	0
B 3.4-10	0	B 3.4-48	0
B 3.4-11	0	B 3.4-49	0
B 3.4-12	0	B 3.4-50	0
B 3.4-13	0	B 3.4-51	0
B 3.4-14	0	B 3.4-52	0
B 3.4-15	0	B 3.4-53	0
B 3.4-16	0	B 3.4-54	0
B 3.4-17	0	B 3.4-55	0
B 3.4-18	0	B 3.4-56	0
B 3.4-19	0	B 3.4-57	0
B 3.4-20	0	B 3.4-58	0
B 3.4-21	0	B 3.4-59	0
B 3.4-22	0	B 3.4-60	0
B 3.4-23	0	B 3.4-61	0
B 3.4-24	0	B 3.4-62	0
B 3.4-25	0	B 3.4-63	0

LIST OF EFFECTIVE PAGES

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
B 3.4-64	0	B 3.5-7	0
B 3.4-65	0	B 3.5-8	0
B 3.4-66	0	B 3.5-9	0
B 3.4-67	0	B 3.5-10	0
B 3.4-68	0	B 3.5-11	0
B 3.4-69	0	B 3.5-12	0
B 3.4-70	0	B 3.5-13	0
B 3.4-71	0	B 3.5-14	0
B 3.4-72	0	B 3.5-15	0
B 3.4-72	0	B 3.5-16	0
B 3.4-73	0	B 3.5-17	0
B 3.4-74	0	B 3.5-18	0
B 3.4-75	0	B 3.5-19	0
B 3.4-76	0	B 3.5-20	0
B 3.4-77	0	B 3.5-21	0
B 3.4-78	0	B 3.5-22	0
B 3.4-79	0	B 3.5-23	0
B 3.4-80	0	B 3.5-24	0
B 3.4-81	0	B 3.5-25	0
B 3.4-82	0	B 3.5-26	0
B 3.4-83	0	B 3.5-27	0
B 3.4-84	0	B 3.5-28	0
B 3.4-85	0	B 3.5-29	0
B 3.4-86	0	B 3.5-30	0
B 3.4-87	0	B 3.5-31	0
B 3.4-88	0	B 3.5-32	0
B 3.4-89	0	B 3.5-33	0
B 3.4-90	0	B 3.6-1	0
B 3.4-91	0	B 3.6-2	0
B 3.4-92	0	B 3.6-3	0
B 3.4-93	0	B 3.6-4	0
B 3.4-94	0	B 3.6-5	0
B 3.5-1	0	B 3.6-6	0
B 3.5-2	0	B 3.6-7	0
B 3.5-3	0	B 3.6-8	0
B 3.5-4	0	B 3.6-9	0
B 3.5-5	0	B 3.6-10	0
B 3.5-6	0	B 3.6-11	0

LIST OF EFFECTIVE PAGES

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
B 3.6-12	0	B 3.6-50	0
B 3.6-13	0	B 3.6-51	0
B 3.6-14	0	B 3.5-52	0
B 3.6-15	0	B 3.6-53	0
B 3.6-16	0	B 3.6-54	0
B 3.6-17	0	B 3.6-55	0
B 3.6-18	0	B 3.6-56	0
B 3.6-19	0	B 3.6-57	0
B 3.6-20	0	B 3.6-58	0
B 3.6-21	0	B 3.6-59	0
B 3.6-22	0	B 3.6-60	0
B 3.6-23	0	B 3.6-61	0
B 3.6-24	0	B 3.6-62	0
B 3.6-25	0	B 3.6-63	0
B 3.6-26	0	B 3.6-64	0
B 3.6-27	0	B 3.6-65	0
B 3.6-28	0	B 3.6-66	0
B 3.6-29	0	B 3.6-67	0
B 3.6-30	0	B 3.6-68	0
B 3.6-31	0	B 3.6-69	0
B 3.6-32	0	B 3.6-70	0
B 3.6-33	0	B 3.6-71	0
B 3.6-34	0	B 3.6-72	0
B 3.6-35	0	B 3.6-73	0
B 3.6-36	0	B 3.6-74	0
B 3.6-37	0	B 3.6-75	0
B 3.6-38	0	B 3.6-76	0
B 3.6-39	0	B 3.6-77	0
B 3.6-40	0	B 3.6-78	0
B 3.6-41	0	B 3.6-79	0
B 3.6-42	0	B 3.6-80	0
B 3.6-43	0	B 3.6-81	0
B 3.6-44	0	B 3.6-82	0
B 3.6-45	0	B 3.6-83	0
B 3.6-46	0	B 3.6-84	0
B 3.6-47	0	B 3.6-85	0
B 3.6-48	0	B 3.6-86	0
B 3.6-49	0	B 3.6-87	0

LIST OF EFFECTIVE PAGES

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
B 3.6-88	0	B 3.7-36	0
B 3.6-89	0	B 3.7-37	0
B 3.6-90	0	B 3.7-38	0
B 3.7-1	0	B 3.7-39	0
B 3.7-2	0	B 3.7-40	0
B 3.7-3	0	B 3.7-41	0
B 3.7-4	0	B 3.7-42	0
B 3.7-5	0	B 3.7-43	0
B 3.7-6	0	B 3.7-44	0
B 3.7-7	0	B 3.7-45	0
B 3.7-8	0	B 3.7-46	0
B 3.7-9	0	B 3.7-47	0
B 3.7-10	0	B 3.7-48	0
B 3.7-11	0	B 3.7-49	0
B 3.7-12	0	B 3.7-50	0
B 3.7-13	0	B 3.7-51	0
B 3.7-14	0	B 3.7-52	0
B 3.7-15	0	B 3.7-53	0
B 3.7-16	0	B 3.7-54	0
B 3.7-17	0	B 3.7-55	0
B 3.7-18	0	B 3.7-56	0
B 3.7-19	0	B 3.7-57	0
B 3.7-20	0	B 3.7-58	0
B 3.7-21	0	B 3.7-59	0
B 3.7-22	0	B 3.7-60	0
B 3.7-23	0	B 3.7-61	0
B 3.7-24	0	B 3.7-62	0
B 3.7-25	0	B 3.7-63	0
B 3.7-26	0	B 3.7-64	0
B 3.7-27	0	B 3.7-65	0
B 3.7-28	0	B 3.7-66	0
B 3.7-29	0	B 3.7-67	0
B 3.7-30	0	B 3.7-68	0
B 3.7-31	0	B 3.7-69	0
B 3.7-32	0	B 3.7-70	0
B 3.7-33	0	B 3.7-71	0
B 3.7-34	0	B 3.7-72	0
B 3.7-35	0	B 3.7-73	0

LIST OF EFFECTIVE PAGES

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
B 3.7-74	0	B 3.8-24	0
B 3.7-75	0	B 3.8-25	0
B 3.7-76	0	B 3.8-26	0
B 3.7-77	0	B 3.8-27	0
B 3.7-78	0	B 3.8-28	0
B 3.7-79	0	B 3.8-29	0
B 3.7-80	0	B 3.8-30	0
B 3.7-81	0	B 3.8-31	0
B 3.7-82	0	B 3.8-32	0
B 3.7-83	0	B 3.8-33	0
B 3.7-84	0	B 3.8-34	0
B 3.7-85	0	B 3.8-35	0
B 3.7-86	0	B 3.8-36	0
B 3.7-87	0	B 3.8-37	0
B 3.7-88	0	B 3.8-38	0
B 3.8-1	0	B 3.8-39	0
B 3.8-2	0	B 3.8-40	0
B 3.8-3	0	B 3.8-41	0
B 3.8-4	0	B 3.8-42	0
B 3.8-5	0	B 3.8-43	0
B 3.8-6	0	B 3.8-44	0
B 3.8-7	0	B 3.8-45	0
B 3.8-8	0	B 3.8-46	0
B 3.8-9	0	B 3.8-47	0
B 3.8-10	0	B 3.8-48	0
B 3.8-11	0	B 3.8-49	0
B 3.8-12	0	B 3.8-50	0
B 3.8-13	0	B 3.8-51	0
B 3.8-14	0	B 3.8-52	0
B 3.8-15	0	B 3.8-53	0
B 3.8-16	0	B 3.8-54	0
B 3.8-17	0	B 3.8-55	0
B 3.8-18	0	B 3.8-56	0
B 3.8-19	0	B 3.8-57	0
B 3.8-20	0	B 3.8-58	0
B 3.8-21	0	B 3.8-59	0
B 3.8-22	0	B 3.8-60	0
B 3.8-23	0	B 3.8-61	0

LIST OF EFFECTIVE PAGES

PAGE NUMBER	AMENDMENT NUMBER
B 3.8-62	0
B 3.8-63	0
B 3.8-64	0
B 3.8-65	0
B 3.8-66	0
B 3.8-67	0
B 3.8-68	0
B 3.8-69	0
B 3.8-70	0
B 3.8-71	0
B 3.8-72	0
B 3.8-73	0
B 3.8-74	0
B 3.8-75	0
B 3.8-76	0
B 3.8-77	0
B 3.8-78	0
B 3.8-79	0
B 3.8-80	0
B 3.8-81	0
B 3.8-82	0
B 3.8-83	0
B 3.8-84	0
B 3.8-85	0
B 3.8-86	0
B 3.8-87	0
B 3.8-88	0
B 3.8-89	0
B 3.8-90	0
B 3.8-91	0
B 3.8-92	0
B 3.8-93	0
B 3.8-94	0
B 3.8-95	0
B 3.8-96	0
B 3.8-97	0
B 3.8-98	0
B 3.9-1	0

PAGE NUMBER	AMENDMENT NUMBER
B 3.9-2	0
B 3.9-3	0
B 3.9-4	0
B 3.9-5	0
B 3.9-6	0
B 3.9-7	0
B 3.9-8	0
B 3.9-10	0
B 3.9-11	0
B 3.9-12	0
B 3.9-13	0
B 3.9-14	0
B 3.9-15	0
B 3.9-16	0
B 3.9-17	0
B 3.9-18	0
B 3.9-19	0
B 3.9-20	0
B 3.9-21	0
B 3.9-22	0
B 3.9-23	0
B 3.9-24	0
B 3.9-25	0
B 3.9-26	0
B 3.9-27	0
B 3.9-28	0

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

Background

GDC 10 (Ref. 1) requires that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur and by requiring that fuel centerline temperature stays below the melting temperature.

The restrictions of this SL prevent overheating of the fuel and cladding, as well as possible cladding perforation, that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak linear heat rate (LHR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

(continued)

BASES

BACKGROUND (continued)

DNB is not a directly measurable parameter during operation; therefore, THERMAL POWER, reactor coolant temperature, and pressure are related to DNB through critical heat flux (CHF) correlations. The primary DNB correlations are the WRB-1 correlation (Ref. 7) for VANTAGE 5H and VANTAGE+ fuel and the WRB-2M correlation (Ref. 8) for RFA-2 fuel with IFMs. These DNB correlations take credit for significant improvement in the accuracy of the CHF predictions. The W-3 CHF correlation (Refs. 9 and 10) is used for conditions outside the range of the WRB-1 correlation for VANTAGE 5H and VANTAGE+ fuel or the WRB-2M correlation for RFA-2 fuel with IFMs.

The proper functioning of the Reactor Protection System (RPS) and steam generator safety valves prevents violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB; and

b. The hot fuel pellet in the core must not experience centerline fuel melting.

The Reactor Trip System setpoints (Ref. 2), in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

Automatic enforcement of these reactor core SLs is provided by the following functions:

a. High pressurizer pressure trip;

b. Low pressurizer pressure trip;

c. Overtemperature ΔT trip;

d. Overpower ΔT trip;

e. Power Range Neutron Flux trip; and

f. Steam generator safety valves.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limitation that the average enthalpy in the hot leg be less than or equal to the enthalpy of saturated liquid also ensures that the ΔT measured by instrumentation, used in the RPS design as a measure of core power, is proportional to core power.

The SLs represent a design requirement for establishing the RPS trip setpoints identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses (as indicated in the FSAR, Ref. 2) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

The curves provided in Figure B 2.1.1-1 show the loci of points of THERMAL POWER, RCS pressure, and average temperature for which the minimum DNBR is not less than the safety analyses limit, that fuel centerline temperature remains below melting, that the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid, or that the exit quality is within the limits defined by the DNBR correlation.

The curves are based on enthalpy hot channel factor limits provided in the COLR. The dashed line of Figure B 2.1.1-1 shows an example of a limit curve at 2235 psig. In addition, it illustrates the various RPS functions that are designed to prevent the unit from reaching the limit.

The SL is higher than the limit calculated when the AFD is within the limits of the $F_1(\Delta I)$ function of the overtemperature ΔT reactor trip. When the AFD is not within the tolerance, the AFD effect on the overtemperature ΔT reactor trips will reduce the setpoints to provide protection consistent with the reactor core SLs (Refs. 3 and 4).

To meet the DNB design criterion, uncertainties in plant operating parameters, nuclear and thermal parameters, fuel fabrication parameters and computer codes must be considered. The effects of these uncertainties have been statistically combined with the correlation uncertainty to determine design limit DNBR values that satisfy the DNB design criterion. SL 2.1.1 reflects the use of the WRB-1 CHF correlation with design limit DNBR values of 1.25/1.24 (typical/thimble) for VANTAGE 5H and VANTAGE+ fuel and the WRB-2M CHF correlation with design limit DNBR values of 1.23/1.23 (typical/thimble) for RFA-2 fuel with IFMs.

Additional DNBR margin is maintained by performing the safety analyses to higher DNBR limits. This margin between the design and safety analysis limit is more than sufficient to offset known DNBR penalties (e.g., rod bow and transition core) and to provide the DNBR margin for operating and design flexibility.

BASES (continued)

APPLICABILITY

SL 2.1.1 only applies in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The steam generator safety valves or automatic protection actions serve to prevent RCS heatup to the reactor core SL conditions or to initiate a reactor trip function, which forces the unit into MODE 3. Setpoints for the reactor trip functions are specified in LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." In MODES 3, 4, 5, and 6, Applicability is not required since the reactor is not generating significant THERMAL POWER.

SAFETY LIMIT VIOLATIONS

The following SL violation responses are applicable to the reactor core SLs.

2.2.1

If SL 2.1.1 is violated, the requirement to go to MODE 3 places the unit in a MODE in which this SL is not applicable.

The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.

2.2.3

If SL 2.1.1 is violated, the NRC Operations Center must be notified within 1 hour, in accordance with 10 CFR 50.72 (Ref. 5).

2.2.4

If SL 2.1.1 is violated, the Plant Manager, Site Vice President, and Nuclear Safety Review Board (NSRB) shall be notified within 24 hours. This 24-hour period provides time for the plant operators and staff to take the appropriate immediate action and assess the condition of the unit before reporting to the senior management.

2.2.5

If SL 2.1.1 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 Plant Manager, Site Vice President, and the Nuclear Safety Review Board (NSRB).

(continued)

BASES

SAFETY LIMIT VIOLATIONS (continued)

2.2.6

If SL 2.1.1 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. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 10, "Reactor Design."
2. Watts Bar FSAR, Section 7.2, "Reactor Trip System."
3. WCAP-8746-A, "Design Bases for the Overtemperature ΔT and the Overpower ΔT Trips," March 1977.
4. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.
5. Title 10, Code of Federal Regulations, Part 50.72, "Immediate Notification Requirements for Operating Nuclear Power Reactors."
6. Title 10, Code of Federal Regulations, Part 50.73, "Licensee Event Report System."
7. WCAP-8762-P-A, "New Westinghouse Correlation WRB-1 for Predicting Critical Heat Flux in Rod Bundles with Mixing Vane Grids," July 1984.
8. WCAP-15025-P-A, “Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17 x 17 Rod Bundles with Modified LPD Mixing Vane Grids,” April 1999.
9. Tong, L. S., "Boiling Crisis and Critical Heat Flux," AEC Critical Review Series, TID-25887, 1972.
10. Tong, L. S., "Critical Heat Fluxes on Rod Bundles," in "Two-Phase Flow and Heat Transfer in Rod Bundles," pages 31 through 41, American Society of Mechanical Engineers, New York, 1969

BASES

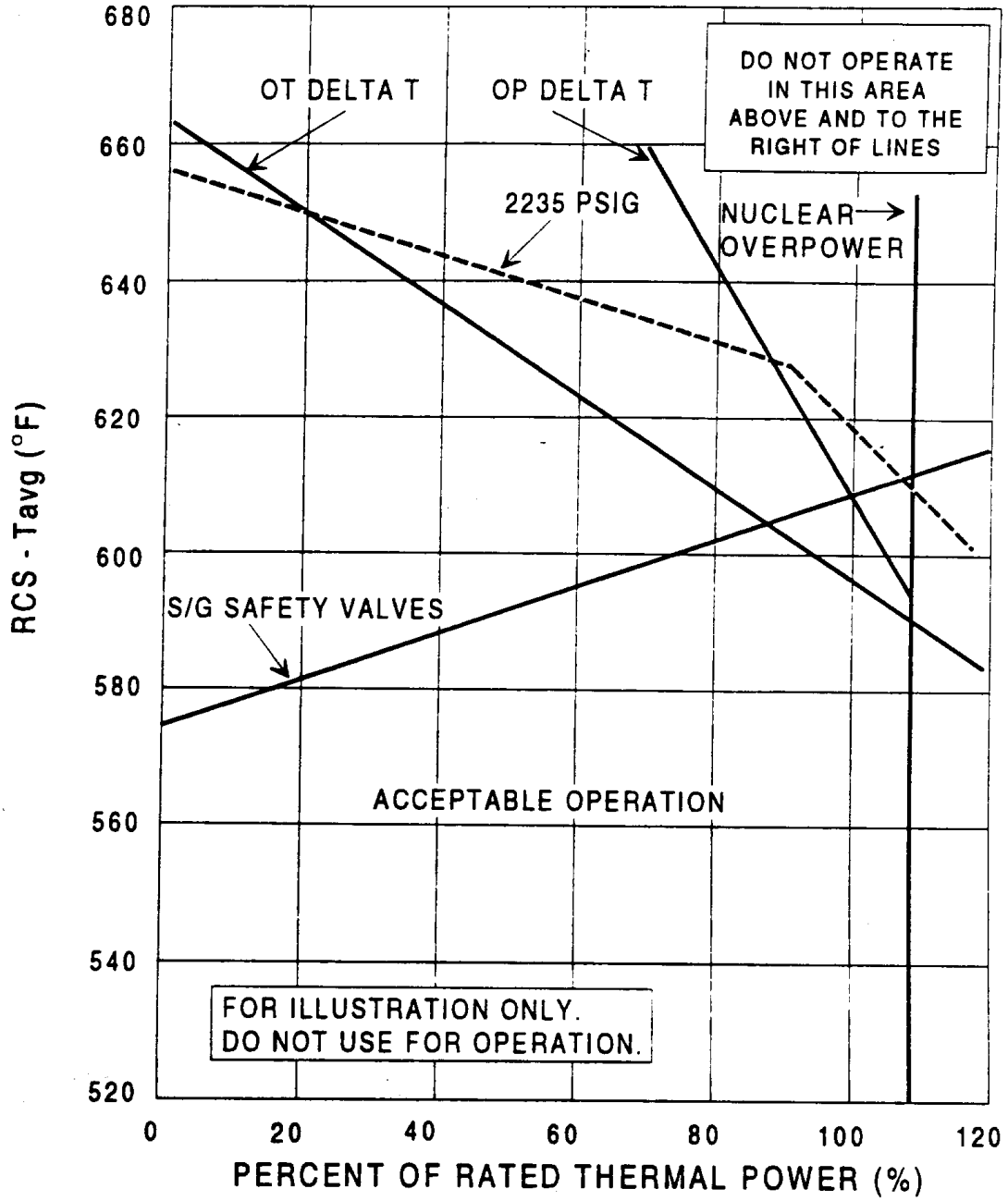


Figure B 2.1.1-1 (page 1 of 1)
Reactor Core Safety Limits vs. Boundary of Protection

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

Background

The SL on RCS pressure protects the integrity of the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. By establishing an upper limit on RCS pressure, the continued integrity of the RCS is ensured. According to 10 CFR 50, Appendix A, GDC 14, "Reactor Coolant Pressure Boundary," and GDC 15, "Reactor Coolant System Design," (Ref. 1), the reactor coolant pressure boundary (RCPB) design conditions are not to be exceeded during normal operation and anticipated operational occurrences (AOOs). Also, in accordance with GDC 28, "Reactivity Limits," (Ref. 1), reactivity accidents, including rod ejection, do not result in damage to the RCPB greater than limited local yielding.

The design pressure of the RCS is 2500 psia. During normal operation and AOOs, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 2). To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure, according to the ASME Code requirements prior to initial operation when there is no fuel in the core. Following inception of unit operation, RCS components shall be pressure tested, in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB. If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere, raising concerns relative to limits on radioactive releases specified in 10 CFR 100, "Reactor Site Criteria," (Ref. 4).

BASES (continued)

APPLICABLE SAFETY ANALYSES

The RCS pressurizer safety valves, the main steam safety valves (MSSVs), and the reactor high pressure trip have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressurizer safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, as specified in Section III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that establishes the required relief capacity, and hence valve size requirements and lift settings, is a complete loss of external load without a direct reactor trip. During the transient, no control actions are assumed, except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve settings.

The Reactor Trip System setpoints (Ref. 5), together with the settings of the MSSVs (Ref. 8), provide pressure protection for normal operation and AOOs. The reactor high pressure trip setpoint is specifically set to provide protection against overpressurization (Ref. 5). The safety analyses for both the high pressure trip and the RCS pressurizer safety valves are performed using conservative assumptions relative to pressure control devices.

More specifically, no credit is taken for operation of the following:

a. Pressurizer power operated relief valves (PORVs);

b. Steam line power operated relief valve (PORV);

c. Steam Dump System;

d. Reactor Control System;

e. Pressurizer Level Control System; or

f. Pressurizer spray valve.

SAFETY LIMITS

The maximum transient pressure allowed in the RCS pressure vessel, piping, valves, and fittings under the ASME Code, Section III, is 110% of design pressure. Therefore, the SL on maximum allowable RCS pressure is 2735 psig (2750 psia).

BASES (continued)

APPLICABILITY

SL 2.1.2 applies in MODES 1, 2, 3, 4, and 5 because this SL could be approached or exceeded in these MODES due to overpressurization events. The SL is not applicable in MODE 6 because the reactor vessel head closure bolts are not fully tightened, making it unlikely that the RCS can be pressurized.

SAFETY LIMIT VIOLATIONS

The following SL violations are applicable to the RCS pressure SL.

2.2.2.1

If the RCS pressure SL is violated when the reactor is in MODE 1 or 2, the requirement is to restore compliance and be in MODE 3 within 1 hour.

Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4).

The allowable Completion Time of 1 hour recognizes the importance of reducing power level to a MODE of operation where the potential for challenges to safety systems is minimized.

2.2.2.2

If the RCS pressure SL is exceeded in MODE 3, 4, or 5, RCS pressure must be restored to within the SL value within 5 minutes. Exceeding the RCS pressure SL in MODE 3, 4, or 5 is more severe than exceeding this SL in MODE 1 or 2, since the reactor vessel temperature may be lower and the vessel material, consequently, less ductile. As such, pressure must be reduced to less than the SL within 5 minutes. The action does not require reducing MODES, since this would require reducing temperature, which would compound the problem by adding thermal gradient stresses to the existing pressure stress.

2.2.3

If the RCS pressure SL is violated, the NRC Operations Center must be notified within 1 hour, in accordance with 10 CFR 50.72 (Ref. 6).

2.2.4

If the RCS pressure SL is violated, the Plant Manager, Site Vice President, and Nuclear Safety Review Board (NSRB) shall be notified within 24 hours. The 24 hour period provides time for the plant operators and staff to take the appropriate immediate action and assess the condition of the unit before reporting to senior management.

(continued)

BASES

SAFETY LIMIT VIOLATIONS (continued)

2.2.5

If the RCS pressure 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. 7). A copy of the report shall also be provided to the Plant Manager, Site Vice President, and NSRB.

2.2.6

If the RCS pressure 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. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 14, "Reactor Coolant Pressure Boundary"; General Design Criterion 15, "Reactor Coolant System Design"; and General Design Criterion 28, "Reactivity Limits."

2. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components," Article NB-7000, "Protection Against Overpressure."

3. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI, IWX-5000, "System Pressure Tests."

4. Title 10, Code of Federal Regulations, Part 100, "Reactor Site Criteria."

5. Watts Bar FSAR, Section 7.2, "Reactor Trip System."

6. Title 10, Code of Federal Regulations, Part 50.72, "Immediate Notification Requirements for Operating Nuclear Power Reactors."

7. Title 10, Code of Federal Regulations, Part 50.73, "Licensee Event Report System."

8. Watts Bar FSAR, Section 10.3, "Main Steam Supply System."

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.8 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.
LCO 3.0.1	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).
LCO 3.0.2	LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that: a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified. There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action 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.

(continued)

BASES

LCO 3.0.2 (continued)

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 exist. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Alternatives that would not result in redundant equipment being inoperable should be used instead. Doing so limits the time both subsystems/trains of a safety function are inoperable and limits the time other conditions exist which result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.

BASES (continued)

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, Completion Times.

(continued)

BASES

LCO 3.0.3 (continued)

A unit shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met.

b. A Condition exists for which the Required Actions have now been performed.

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.3 is exited.

The time limits of Specification 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is reached in 2 hours, then the time allowed for reaching MODE 4 is the next 11 hours, because the total time for reaching MODE 4 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

(continued)

BASES

LCO 3.0.3 (continued)

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.13, "Fuel Storage Pool Water Level." LCO 3.7.13 has an Applicability of "During movement of irradiated fuel assemblies in the fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.13 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.13 of "Suspend movement of irradiated fuel assemblies in the fuel storage pool." is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance

(continued)

BASES

LCO 3.0.4 (continued)

activities be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4.b, must take into account all inoperable Technical Specifications equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 3. Regulatory Guide 1.160 Revision 3 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 4A. These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

LCO 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The LCO 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the LCO, the use of the LCO 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the LCO 3.0.4.b allowance is prohibited. The LCOs governing these system and components contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

(continued)

BASES

LCO 3.0.4 (continued)

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on a Note in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., Reactor Coolant System Specific Activity), and may be applied to other Specifications based on NRC plant-specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 3.0.1 or SR 3.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

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.

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the unit is maintained in a safe condition are specified in the support system LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

(continued)

BASES

LCO 3.0.6 (continued)

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCOs' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the unit is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.7.2.18, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required. The cross train check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

BASES

LCO 3.0.6 (continued)

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

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

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the plant. These special tests and operations are necessary to demonstrate select plant performance characteristics, to perform special maintenance activities, and to perform special evolutions.

Test Exception LCOs 3.1.9 and 3.1.10 allow specified Technical Specification (TS) requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test will remain in effect.

The Applicability of a Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Test Exception LCOs is optional. A special test or operation may be performed either under the provisions of the appropriate Test Exception LCO or under the other applicable TS requirements. If it is desired to perform the special test or operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs	SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.
SR 3.0.1	SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO. Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when: a. The systems or components are known to be inoperable, although still meeting the SRs; or b. The requirements of the Surveillance(s) are known not to be met between required Surveillance performances. Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a test exception are only applicable when the test exception is used as an allowable exception to the requirements of a Specification. Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

(continued)

BASES

SR 3.0.1 (continued)

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per . . ." interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. Therefore, when a test interval is specified in the regulations, the test interval cannot be extended by the TS, and the surveillance requirement will include a note in the frequency stating, "SR 3.0.2 does not apply." An example of an exception when the test interval is not specified in the regulations, is the discussion in the Containment Leakage Rate Testing Program, that SR 3.0.2 does not apply. This exception is provided because the program already includes extension of test intervals.

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per . . ." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required

(continued)

BASES

SR 3.0.2 (continued)

Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified, with the exception of surveillances required to be performed on a 31-day frequency. For surveillances performed on a 31-day frequency, the normal surveillance interval may be extended in accordance with Specification 3.0.2 cyclically as required to remain synchronized to the maintenance work schedules. This practice is acceptable based on the results of an evaluation of 31-day frequency surveillance test histories that demonstrate that no adverse failure rate changes have occurred nor would be expected to develop as a result of cyclical use of surveillance interval extensions and the fact that the total number of 31-day frequency surveillances performed in any one-year period remains unchanged.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

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

(continued)

SR 3.0.3 (continued)

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

SR 3.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.” This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

(continued)

BASES

SR 3.0.3 (continued)

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of the Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due to Surveillance not being met in accordance with LCO 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

(continued)

BASES

SR 3.0.4 (continued)

The provisions of SR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO's Applicability, would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, Frequency.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM) - T_{avg} > 200°F

BASES

BACKGROUND

According to GDC 26 (Ref. 1), the reactivity control systems must be redundant and capable of holding the reactor core subcritical when shut down under cold conditions. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel.

SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion or trip of all shutdown and control rods, assuming that the single rod cluster assembly of highest reactivity worth is fully withdrawn.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are provided by the use of movable control assemblies and soluble boric acid in the Reactor Coolant System (RCS). The Control Rod System can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the Control Rod System, together with the soluble boron, provides the SDM during power operation. The Control Rod System is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the rod of highest reactivity worth remains fully withdrawn. The soluble boron system can compensate for fuel depletion during operation and all xenon burnout reactivity changes and maintain the reactor subcritical under cold conditions.

During power operation, SDM control is ensured by operating with the shutdown banks within the limits of LCO 3.1.6, "Shutdown Bank Insertion Limits," and the control banks within the limits of LCO 3.1.7, "Control Bank Insertion Limits." When the unit is in the shutdown and refueling modes, the SDM requirements are met by means of adjustments to the RCS boron concentration.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in safety analyses. The safety analysis (Ref. 2) establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with the assumption of the highest worth rod stuck out on a trip.

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are maintained. This is done by ensuring that:

a. The reactor can be made subcritical from all operating conditions, transients, and Design Basis Events;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (departure from nucleate boiling ratio (DNBR), fuel centerline temperature limits for AOOs, and ≤ 280 cal/gm energy deposition for the rod ejection accident); and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

The most limiting accident for the SDM requirements is based on a main steam line break (MSLB), as described in the accident analysis (Ref. 2). The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected steam generator (SG), and consequently the RCS. This results in a reduction of the reactor coolant temperature. The resultant coolant shrinkage causes a reduction in pressure. In the presence of a negative moderator temperature coefficient, this cooldown causes an increase in core reactivity. As RCS temperature decreases, the severity of an MSLB decreases until the MODE 5 value is reached. The most limiting MSLB, with respect to potential fuel damage before a reactor trip occurs, is a guillotine break of a main steam line inside containment initiated at the end of core life. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the MSLB, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power, and THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In addition to the limiting MSLB transient, the SDM requirement must also protect against:

a. Inadvertent boron dilution;

b. An uncontrolled rod withdrawal from subcritical or low power condition;

c. Startup of an inactive reactor coolant pump (RCP); and

d. Rod ejection.

Each of these events is discussed below.

In the boron dilution analysis, the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS and the assumed dilution flow rate, directly affect the results of the analysis. This event is most limiting at the beginning of core life, when critical boron concentrations are highest.

Depending on the system initial conditions and reactivity insertion rate, the uncontrolled rod withdrawal transient is terminated by either a high power level trip or an Overtemperature ΔT trip. In all cases, power level, RCS pressure, linear heat rate, and the DNBR do not exceed allowable limits.

The startup of an inactive RCP will not result in a "cold water" criticality, even if the maximum difference in temperature exists between the SG and the core. The maximum positive reactivity addition that can occur due to an inadvertent RCP start is less than half the minimum required SDM. Startup of an idle RCP cannot, therefore, produce a return to power from the hot standby condition.

The ejection of a control rod rapidly adds reactivity to the reactor core, causing both the core power level and heat flux to increase with corresponding increases in reactor coolant temperatures and pressure. The ejection of a rod also produces a time dependent redistribution of core power.

SDM satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed from the control room, SDM is considered an initial condition process variable because it is periodically monitored to ensure that the unit is operating within the bounds of accident analysis assumptions.

BASES (continued)

LCO

SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration.

The MSLB (Ref. 2) and the boron dilution (Ref. 3) accidents are the most limiting analyses that establish the SDM value of the LCO. For MSLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4). For the boron dilution accident, if the LCO is violated, the minimum required time assumed for operator action to terminate dilution may no longer be applicable.

APPLICABILITY

In MODE 2 with k_{eff} < 1.0 and in MODES 3 and 4, the SDM requirements are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analyses discussed above. In MODE 5, SDM is addressed by LCO 3.1.2, "SHUTDOWN MARGIN (SDM) - T_{avg} ≤ 200°F." In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration." In MODES 1 and 2, SDM is ensured by complying with LCO 3.1.6 and LCO 3.1.7.

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that boration will be continued until the SDM requirements are met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a concentrated solution, such as that normally found in the boric acid storage tank, or the refueling water storage tank. The operator should borate with the best source available for the plant conditions.

(continued)

BASES (continued)

ACTIONS (continued)

In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of cycle when the boron concentration may approach or exceed 2000 ppm. Assuming that a value of 1% $\Delta k/k$ must be recovered and a boration flow rate of 35 gpm, it is possible to increase the boron concentration of the RCS by 100 ppm in approximately 35 minutes. If a boron worth of 10 pcm/ppm is assumed, this combination of parameters will increase the SDM by 1% $\Delta k/k$. These boration parameters of 35 gpm and 6120 ppm represent typical values and are provided for the purpose of offering a specific example.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODES 1 and 2, SDM is verified by observing that the requirements of LCO 3.1.6 and LCO 3.1.7 are met. In the event that a rod is known to be untrippable, however, SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth.

In MODE 2 with k_{eff} < 1.0 and in MODES 3 and 4, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Design isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and the low probability of an accident occurring without the required SDM. This allows time for the operator to collect the required data, which includes performing a boron concentration analysis, and complete the calculation.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 26, "Reactivity Control System Redundancy and Capability."

2. Watts Bar FSAR, Section 15.4.2, "Major Secondary System Pipe Rupture."

3. Watts Bar FSAR, Section 15.2.4, "Uncontrolled Boron Dilution."

4. Title 10, Code of Federal Regulations, Part 100, "Reactor Site Criteria."

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 SHUTDOWN MARGIN (SDM) - $T_{avg} \leq 200°F$

BASES

BACKGROUND

According to GDC 26 (Ref. 1), the reactivity control systems must be redundant and capable of holding the reactor core subcritical when shut down under cold conditions. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel.

SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion or trip of all shutdown and control rods, assuming the single rod cluster assembly of highest reactivity worth is fully withdrawn.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are provided by the use of movable control assemblies and soluble boric acid in the Reactor Coolant System (RCS). The Control Rod System can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the Control Rod System, together with the soluble boron, provides SDM during power operation. The Control Rod System is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits assuming that the rod of highest reactivity worth remains fully withdrawn. The soluble boron system can compensate for fuel depletion during operation and all xenon burnout reactivity changes, and maintain the reactor subcritical under cold conditions.

During power operation, SDM control is ensured by operating with the shutdown banks within the limits of LCO 3.1.6, "Shutdown Bank Insertion Limits," and the control banks within the limits of LCO 3.1.7, "Control Bank Insertion Limits." When the unit is in the shutdown and refueling modes, the SDM requirements are met by means of adjustments to the RCS boron concentration.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in the safety analysis. The safety analysis establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs with the assumption of the highest worth rod stuck out on a trip.

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are maintained. This is done by ensuring that:

a. The reactor can be made subcritical from all operating conditions, transients, and Design Basis Events;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (departure from nucleate boiling ratio, fuel centerline temperature limits for AOOs, and ≤ 280 cal/gm energy deposition for the rod ejection accident); and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

The Interim Operating Procedure (Ref. 3) assures sufficient operator action time for the mitigation of an uncontrolled boron dilution event (Ref. 2) in MODE 5. This procedure is independent of SDM and uses the Residual Heat Removal System flowrate, and the calculated critical boron concentration to specify a minimum allowable boron concentration. In MODE 6, this accident is prevented by administrative controls which isolate the RCS from the potential sources of unborated water.

SDM satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed from the control room, SDM is considered an initial condition process variable because it is periodically monitored to ensure that the unit is operating within the bounds of accident analysis assumptions.

LCO

SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration.

BASES (continued)

APPLICABILITY

In MODE 5, the SDM requirements are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analyses discussed above. In MODE 2 with $K_{eff} < 1.0$ and in MODES 3 and 4, the SDM requirements are given in LCO 3.1.1, "SHUTDOWN MARGIN (SDM) - $T_{avg} > 200°F$." In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration." In MODE 1 and in MODE 2 with $K_{eff} \geq 1.0$, SDM is ensured by complying with LCO 3.1.6 and LCO 3.1.7.

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that boration will be continued until the SDM requirements are met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a concentrated solution, such as that normally found in the boric acid storage tank or the refueling water storage tank. The operator should borate with the best source available for the plant conditions.

In determining the boration flow rate the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of cycle, when the boron concentration may approach or exceed 2000 ppm. Assuming that a value of 1% $\Delta k/k$ must be recovered and a boration flow rate of 35 gpm, it is possible to increase the boron concentration of the RCS by 100 ppm in approximately 35 minutes. If a boron worth of 10 pcm/ppm is assumed, this combination of parameters will increase the SDM by 1% $\Delta k/k$. These boration parameters of 35 gpm and 6120 ppm represent typical values and are provided for the purpose of offering a specific example.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

In MODE 5, the SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Design isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and on the low probability of an accident occurring without the required SDM. This allows time enough for the operator to collect the required data, which includes performing a boron concentration analysis, and complete the calculation.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 26, "Reactivity Control System Redundancy and Capability."

2. Watts Bar FSAR, Section 15.2.4, "Uncontrolled Boron Dilution."

3. WAT-D-7909, "Tennessee Valley Authority, Watts Bar Nuclear Plant Unit Numbers 1 and 2, Uncontrolled Boron Dilution Event Reanalysis and Interim Operating Procedure, FSAR Revision Section 15.2.4 and Licensing Verification Open Item Report OILV-4060 R0", March 31, 1989.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Core Reactivity

BASES

BACKGROUND

According to GDC 26, GDC 28, and GDC 29 (Ref. 1), reactivity shall be controllable, such that subcriticality is maintained under cold conditions, and acceptable fuel design limits are not exceeded during normal operation and anticipated operational occurrences. Therefore, reactivity balance is used as a measure of the predicted versus measured core reactivity during power operation. The periodic confirmation of core reactivity is necessary to ensure that Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, control rod worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SDM or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)-T_{avg} > 200°F") in ensuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons such as burnable absorbers, producing zero net reactivity. Excess reactivity can be inferred from the boron letdown curve (or critical boron curve), which provides an indication of the soluble boron concentration in the Reactor Coolant System (RCS) versus cycle burnup. Periodic measurement of the RCS boron concentration for comparison with the predicted value with other variables fixed (such as rod height, temperature, pressure, and power), provides a convenient method of ensuring that core reactivity is within design expectations and that the calculational models used to generate the safety analysis are adequate.

(continued)

BASES

BACKGROUND (continued)

In order to achieve the required fuel cycle energy output, the uranium enrichment, in the new fuel loading and in the fuel remaining from the previous cycle, provides excess positive reactivity beyond that required to sustain steady state operation throughout the cycle. When the reactor is critical at RTP and moderator temperature, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, whatever neutron poisons (mainly xenon and samarium) are present in the fuel, and the RCS boron concentration.

When the core is producing THERMAL POWER, the fuel is being depleted and excess reactivity is decreasing. As the fuel and burnable absorbers deplete, the RCS boron concentration is adjusted to compensate for the net core reactivity change to maintain constant THERMAL POWER. The boron letdown curve is based on steady state operation at RTP. Therefore, deviations from the predicted boron letdown curve may indicate deficiencies in the design analysis, deficiencies in the calculational models, or abnormal core conditions, and must be evaluated.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for core reactivity are that the reactivity balance limit ensures plant operation is maintained within the assumptions of the safety analyses.

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations. Every accident evaluation (Ref. 2) is, therefore, dependent upon accurate evaluation of core reactivity. In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod ejection accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity balance additionally ensures that the nuclear methods provide an accurate representation of the core reactivity.

Design calculations and safety analyses are performed for each fuel cycle for the purpose of predetermining reactivity behavior and the RCS boron concentration requirements for reactivity control during fuel depletion.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted RCS boron concentrations for identical core conditions at beginning of cycle (BOC) do not agree, then the assumptions used in the initial and reload cycle design analysis or the calculational models used to predict soluble boron requirements may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown curve that develop during fuel depletion may be an indication that the calculational model is not adequate for core burnups beyond BOC, or that an unexpected change in core conditions has occurred.

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RTP following startup from initial fuel loading or a refueling outage, with the control rods in their normal positions for power operation. The normalization is performed at BOC conditions, so that core reactivity relative to predicted values can be continually monitored and evaluated as core conditions change during the cycle.

Core reactivity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Long term core reactivity behavior is a result of the core physics design and cannot be easily controlled once the core design is fixed. During operation, therefore, the LCO can only be ensured through measurement and tracking, and appropriate actions taken as necessary. Large differences between actual and predicted core reactivity may indicate that the assumptions of the DBA and transient analyses are no longer valid, or that the uncertainties in the Nuclear Design Methodology are larger than expected. A limit on the reactivity balance of ± 1% $\Delta k/k$ has been established based on engineering judgment. A 1% $\Delta k/k$ deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

(continued)

BASES

LCO (continued)

When measured core reactivity is within 1% $\Delta k/k$ of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits. Since deviations from the limit are normally detected by comparing predicted and measured steady state RCS critical boron concentrations, the difference between measured and predicted values would be dependent on the boron worth. These values are well within the uncertainty limits for analysis of boron concentration samples, so that spurious violations of the limit due to uncertainty in measuring the RCS boron concentration are unlikely.

APPLICABILITY

The limits on core reactivity must be maintained during MODES 1 and 2 because a reactivity balance must exist when the reactor is critical or producing THERMAL POWER. As the fuel depletes, core conditions are changing, and confirmation of the reactivity balance ensures the core is operating as designed. This Specification does not apply in MODES 3, 4, and 5 because the reactor is shut down and the reactivity balance is used only as a comparison of predicted versus measured reactivity when the reactor is critical.

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Boron Concentration") ensure that fuel movements are performed within the bounds of the safety analysis. An SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling).

BASES (continued)

ACTIONS

A.1 and A.2

Should an anomaly develop between measured and predicted core reactivity, an evaluation of the core design and safety analysis must be performed. Core conditions are evaluated to determine their consistency with input to design calculations. Measured core and process parameters are evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models are reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 72 hours is based on the low probability of a DBA occurring during this period, and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

Following evaluations of the core design and safety analysis, the cause of the reactivity anomaly may be resolved. If the cause of the reactivity anomaly is a mismatch in core conditions at the time of RCS boron concentration sampling, then a recalculation of the RCS boron concentration requirements may be performed to demonstrate that core reactivity is behaving as expected. If an unexpected physical change in the condition of the core has occurred, it must be evaluated and corrected, if possible. If the cause of the reactivity anomaly is in the calculation technique, then the calculational models must be revised to provide more accurate predictions. If any of these results are demonstrated, and it is concluded that the reactor core is acceptable for continued operation, then the boron letdown curve may be renormalized and power operation may continue. If operational restriction or additional SRs are necessary to ensure the reactor core is acceptable for continued operation, then they must be defined.

The required Completion Time of 72 hours is adequate for preparing whatever operating restrictions or Surveillances that may be required to allow continued reactor operation.

B.1

If the core reactivity cannot be restored to within the 1% Δk/k limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. If the SDM for MODE 3 is not met, then the boration required by SR 3.1.1.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made, considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Surveillance is performed prior to entering MODE 1 as an initial check on core conditions and design calculations at BOC. The SR is modified by a Note. The Note indicates that any normalization of predicted core reactivity to the measured value must take place within the first 60 effective full power days (EFPD) after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations. The required subsequent Frequency of 31 EFPD, following the initial 60 EFPD after entering MODE 1, is acceptable, based on the slow rate of core changes due to fuel depletion and the presence of other indicators (QPTR, AFD, etc.) for prompt indication of an anomaly.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 26, "Reactivity Control System Redundancy and Capability"; General Design Criterion 28, "Reactivity Limits"; and General Design Criterion 29, "Protection Against Anticipated Operational Occurrences."

2. Watts Bar FSAR, Section 15.0, "Accident Analyses."

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to GDC 11 (Ref. 1), the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The reactor is designed to operate with a negative MTC over the largest possible range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Both initial and reload cores are designed so that the beginning of cycle (BOC) MTC is less than zero. The actual value of the MTC is dependent on core characteristics, such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed distributed poisons to yield an MTC at BOC within the range analyzed in the plant accident analysis. For some core designs, the burnable absorbers may burn out faster than the fuel depletes early in the cycle. This may cause the boron concentration to increase with burnup early in the cycle and the most positive MTC not to occur at BOC, but somewhat later in the cycle. For these core designs, an as-measured criterion is established that is sufficiently less positive than zero to ensure that the MTC remains within the LCO upper limit during the cycle. The end of cycle (EOC) MTC is also limited by the requirements of the accident analysis. Fuel cycles that are designed to achieve high burnups or that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the EOC limit.

(continued)

BASES

BACKGROUND (continued)

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting conditions assumed in the FSAR accident and transient analyses.

If the LCO limits are not met, the unit response during transients may not be as predicted. The core could violate criteria that prohibit a return to criticality during non-MSLB events, or the departure from nucleate boiling ratio criteria of the approved correlation may be violated, which could lead to a loss of the fuel cladding integrity.

The SRs for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits, since this coefficient changes slowly, due principally to changes in RCS boron concentration associated with fuel and burnable absorber burnup.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified MTC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2); and

b. The MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

The FSAR, Chapter 15 (Ref. 2), contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the most positive value and most negative value of the MTC are important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions to ensure that the accident results are bounding (Ref. 3).

The consequences of accidents that cause core overheating must be evaluated when the MTC is at the most positive value. Such accidents include the rod withdrawal transient from either zero (Ref. 4) or RTP, loss of main feedwater flow, and loss of forced reactor coolant flow. The consequences of accidents that cause core overcooling must be evaluated when the MTC is at the most negative value. Such accidents include sudden feedwater flow increase and sudden decrease in feedwater temperature.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is the BOC or EOC life. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

MTC values are bounded in initial and reload safety evaluations by assuming steady state conditions at BOC and EOC. An EOC measurement is conducted at conditions when the RCS boron concentration reaches approximately 300 ppm. The measured value may be extrapolated to project the EOC value in order to confirm reload design predictions.

MTC satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.4 requires the MTC to be within specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the initial and reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the original accident analysis during operation.

Assumptions made in safety analyses require that the MTC be less positive than a given upper bound and more positive than a given lower bound. The MTC is most positive at or near BOC; this upper bound must not be exceeded. This maximum upper limit occurs at or near BOC, all rods out (ARO), hot zero power conditions. For some core designs, the burnable absorbers may burn out faster than the fuel depletes early in the cycle. This may cause the boron concentration to increase with burnup early in the cycle and the most positive MTC not to occur at BOC, but somewhat later in the cycle. Therefore, an as-measured criterion is established in the COLR that is sufficiently less positive than zero to ensure that the MTC remains within the LCO upper limit during the cycle. This criterion is not an LCO MTC limit; the COLR prescribes appropriate administrative controls for exceeding this value consistent with SR 3.1.4.1. At EOC, the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

(continued)

BASES

LCO (continued)

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The Surveillance checks at BOC and EOC on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

The LCO establishes a maximum positive value (upper limit) that cannot be exceeded. The BOC positive limit and the EOC negative limit are established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

In MODE 1, the limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled CONTROL ROD assembly or group withdrawal) will not violate the assumptions of the accident analysis. The lower MTC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents will not violate the assumptions of the accident analysis. In MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents using the MTC as an analysis assumption are initiated from these MODES.

BASES (continued)

ACTIONS

A.1

If the BOC MTC upper limit is violated, administrative withdrawal limits for control banks must be established to maintain the MTC within its upper limit. The MTC becomes more negative with control bank insertion and decreased boron concentration. A Completion Time of 24 hours provides enough time for evaluating the MTC measurement and computing the required bank withdrawal limits.

Using physics calculations, the time in cycle life at which the calculated MTC will meet the LCO requirement can be determined. At this point in core life Condition A no longer exists. The unit is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

B.1

If the required administrative withdrawal limits at BOC are not established within 24 hours, the unit must be brought to MODE 2 with $k_{eff} < 1.0$ to prevent operation with an MTC that is more positive than that assumed in safety analyses.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

C.1

Exceeding the EOC MTC limit means that the safety analysis assumptions for the EOC accidents that use a bounding negative MTC value may be invalid. If the EOC MTC limit is exceeded, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 4 within 12 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

This SR requires measurement of the MTC at BOC prior to entering MODE 1 in order to demonstrate compliance with the most positive MTC LCO. Meeting the upper limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels.

The BOC MTC value for ARO will be inferred from isothermal temperature coefficient measurements obtained during the physics tests after initial fuel loading and refueling. The ARO value can be directly compared to the BOC as-measured criterion provided in the COLR. Compliance with this as-measured criterion ensures that the MTC will remain within the LCO upper limit during the cycle. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

SR 3.1.4.2 and SR 3.1.4.3

In similar fashion, the LCO demands that the MTC be less negative than the specified value for EOC full power conditions. This measurement may be performed at any THERMAL POWER, but its results must be extrapolated to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC value will gradually become more negative with further core depletion and boron concentration reduction, a 300 ppm SR value of MTC should be less negative than the EOC LCO limit. The 300 ppm SR value is sufficiently less negative than the EOC LCO limit value to ensure that the LCO limit will be met when the 300 ppm Surveillance criterion is met.

SR 3.1.4.3 is modified by a Note that includes the following requirements:

a. If the 300 ppm Surveillance limit is exceeded, it is possible that the EOC limit on MTC could be reached before the planned EOC. Because the MTC changes slowly with core depletion, the Frequency of 14 effective full power days is sufficient to avoid exceeding the EOC limit.

b. The Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is more positive than the 60 ppm Surveillance limit, the EOC limit will not be exceeded because of the gradual manner in which MTC changes with core burnup.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 11, "Reactor Inherent Protection."

2. Watts Bar FSAR, Section 15.0, "Accident Analyses."

3. WCAP 9272-P-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

4. Watts Bar FSAR, Section 15.2.1, "Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical Condition."

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Rod Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY (e.g., trippability) of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," and GDC 26, "Reactivity Control System Redundancy and Capability," (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2).

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved by their control rod drive mechanisms (CRDMs). Each CRDM moves its RCCA one step (approximately 5/8 inch) at a time, but at varying rates (steps per minute) depending on the signal output from the Rod Control System.

The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control (Shutdown Banks C and D have only one group each). A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. Except for Shutdown Banks C and D,

(continued)

BASES

BACKGROUND (continued)

a bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and four shutdown banks.

The shutdown banks are maintained either in the fully inserted or fully withdrawn position. The control banks are moved in an overlap pattern, using the following withdrawal sequence: When control bank A reaches a predetermined height in the core, control bank B begins to move out with control bank A. Control bank A stops at the position of maximum withdrawal, and control bank B continues to move out. When control bank B reaches a predetermined height, control bank C begins to move out with control bank B. This sequence continues until control banks A, B, and C are at the fully withdrawn position, and control bank D is approximately halfway withdrawn. The insertion sequence is the opposite of the withdrawal sequence. The control rods are arranged in a radially symmetric pattern, so that control bank motion does not introduce radial asymmetries in the core power distributions.

The axial position of shutdown rods and control rods is indicated by two separate and independent systems, which are the Bank Demand Position Indication System (commonly called group step counters) and the Rod Position Indication (RPI) System.

The Bank Demand Position Indication System counts the pulses from the rod control system that moves the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The RPI System provides an accurate indication of actual control rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube with a center to center distance of 3.75 inches, which is six steps. The normal indication accuracy of the RPI System is ± 6 steps (± 3.75 inches), and the maximum uncertainty is ± 12 steps (± 7.5 inches). With an indicated deviation of 12 steps between the group step counter and RPI, the maximum deviation between actual rod position and the demand position could be 24 steps, or 15 inches.

BASES (continued)

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (Ref. 3). The acceptance criteria for addressing control rod inoperability or misalignment are that:

a. There be no violations of:

   1. specified acceptable fuel design limits, or

   2. Reactor Coolant System (RCS) pressure boundary integrity; and

b. The core remains subcritical after accident transients other than a main steam line break (MSLB).

Two types of misalignment are distinguished. During movement of a control rod group, one rod may stop moving, while the other rods in the group continue. This condition may cause excessive power peaking. The second type of misalignment occurs if one rod fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the control rods to meet the SDM requirement, with the maximum worth rod stuck fully withdrawn.

Three types of analysis are performed in regard to static rod misalignment (Ref. 4). The first type of analysis considers the case where any one rod is completely inserted into the core with all other rods completely withdrawn. With control banks at their insertion limits, the second type of analysis considers the case when any one rod is completely inserted into the core. The third type of analysis considers the case of a completely withdrawn single rod from a bank inserted to its insertion limit. Satisfying limits on departure from nucleate boiling ratio in both of these cases bounds the situation when a rod is misaligned from its group by 12 steps.

Another type of misalignment occurs if one RCCA fails to insert upon a reactor trip in response to a main steam pipe rupture and remains stuck fully withdrawn. This condition is assumed in the evaluation to determine that the required SDM is met with the maximum worth RCCA also fully withdrawn (Ref. 5). The reactor is shutdown by the boric acid injection delivered by the ECCS.

The Required Actions in this LCO ensure that either deviations from the alignment limits will be corrected or that THERMAL POWER will be adjusted so that excessive local linear heat rates (LHRs) will not occur, and that the requirements on SDM and ejected rod worth are preserved.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Continued operation of the reactor with a misaligned control rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy hot channel factor ($F^N_{\Delta H}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned, the assumptions that are used to determine the rod insertion limits, AFD limits, and quadrant power tilt limits are not preserved. Therefore, the limits may not preserve the design peaking factors, and $F_Q(Z)$ and $F^N_{\Delta H}$ must be verified directly using incore power distribution measurements. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(Z)$ and $F^N_{\Delta H}$ to the operating limits.

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The limits on shutdown or control rod alignments ensure that the assumptions in the safety analysis will remain valid. The requirements on OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The OPERABILITY requirements also ensure that the RCCAs and banks maintain the correct power distribution and rod alignment.

The requirement to maintain the rod alignment to within plus or minus 12 steps is conservative. The minimum misalignment assumed in safety analysis is 24 steps (15 inches), and in some cases a total misalignment from fully withdrawn to fully inserted is assumed.

Failure to meet the requirements of this LCO may produce unacceptable power peaking factors and LHRs, or unacceptable SDMs, all of which may constitute initial conditions inconsistent with the safety analysis.

BASES (continued)

APPLICABILITY

The requirements on RCCA OPERABILITY and alignment are applicable in MODES 1 and 2 because these are the only MODES in which neutron (or fission) power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the control rods are bottomed and the reactor is shut down and not producing fission power. In the shutdown MODES, the OPERABILITY of the shutdown and control rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. See LCO 3.1.1, "SHUTDOWN MARGIN (SDM) - T_{avg} > 200°F," for SDM in MODES 3 and 4, LCO 3.1.2, "Shutdown Margin (SDM) - T_{avg} ≤ 200°F" for SDM in MODE 5, and LCO 3.9.1, "Boron Concentration," for boron concentration requirements during refueling.

ACTIONS

A.1.1 and A.1.2

When one or more rods are untrippable, there is a possibility that the required SDM may be adversely affected. Under these conditions, it is important to determine the SDM, and if it is less than the required value, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate for determining SDM and, if necessary, for initiating boration to restore SDM.

In this situation, SDM verification must include the worth of the untrippable rod, as well as a rod of maximum worth.

A.2

If the untrippable rod(s) cannot be restored to OPERABLE status, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

B.1

When a rod becomes misaligned, it can usually be moved and is still trippable. If the rod can be realigned within the Completion Time of 1 hour, local xenon redistribution during this short interval will not be significant, and operation may proceed without further restriction.

An alternative to realigning a single misaligned RCCA to the group average position is to align the remainder of the group to the position of the misaligned RCCA. However, this must be done without violating the bank sequence, overlap, and insertion limits specified in LCO 3.1.6, "Shutdown Bank Insertion Limits," and LCO 3.1.7, "Control Bank Insertion Limits." The Completion Time of 1 hour gives the operator sufficient time to adjust the rod positions in an orderly manner.

B.2.1.1 and B.2.1.2

With a misaligned rod, SDM must be verified to be within limit or boration must be initiated to restore SDM to within limit.

In many cases, realigning the remainder of the group to the misaligned rod may not be desirable. For example, realigning control bank B to a rod that is misaligned 15 steps from the top of the core would require a significant power reduction, since control bank D must be moved fully in and control bank C must be moved in to approximately 100 to 115 steps.

Power operation may continue with one RCCA trippable but misaligned, provided that SDM is verified within 1 hour.

The Completion Time of 1 hour represents the time necessary for determining the actual unit SDM and, if necessary, aligning and starting the necessary systems and components to initiate boration.

(continued)

BASES

ACTIONS (continued)

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6

For continued operation with a misaligned rod, RTP must be reduced, SDM must periodically be verified within limits, hot channel factors ($F_Q(Z)$ and $F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible.

Reduction of power to 75% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded (Ref. 6). The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

Verifying that $F_Q(Z)$ and $F^N_{\Delta H}$ are within the required limits ensures that current operation at 75% RTP with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain an incore power distribution measurement and to calculate $F_Q(Z)$ and $F^N_{\Delta H}$.

Once current conditions have been verified acceptable, time is available to perform evaluations of accident analysis to determine that core limits will not be exceeded during a Design Basis Event for the duration of operation under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

C.1

When Required Actions cannot be completed within their Completion Time, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours, which obviates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging the plant systems.

(continued)

BASES

ACTIONS (continued)

D.1.1 and D.1.2

More than one control rod becoming misaligned from its group average position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. One hour allows the operator adequate time to determine SDM. Restoration of the required SDM, if necessary, requires increasing the RCS boron concentration to provide negative reactivity, as described in the Bases of LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and start the boric acid pumps. Boration will continue until the required SDM is restored.

D.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement, the unit conditions fall outside of the accident analysis assumptions. Since automatic bank sequencing would continue to cause misalignment, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable.

To achieve this status, the unit must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Verification that individual rod positions are within alignment limits at a Frequency of 12 hours provides a history that allows the operator to detect a rod that is beginning to deviate from its expected position. If the rod position deviation monitor is inoperable, a Frequency of 4 hours accomplishes the same goal. The specified Frequency takes into account other rod position information that is continuously available to the operator in the control room, so that during actual rod motion, deviations can immediately be detected.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.5.2

Verifying each control rod is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2, tripping each control rod would result in radial or axial power tilts, or oscillations. Exercising each individual control rod every 92 days provides increased confidence that all rods continue to be OPERABLE without exceeding the alignment limit, even if they are not regularly tripped. Moving each control rod by 10 steps will not cause radial or axial power tilts, or oscillations, to occur. The 92 day Frequency takes into consideration other information available to the operator in the control room and SR 3.1.5.1, which is performed more frequently and adds to the determination of OPERABILITY of the rods. Between required performances of SR 3.1.5.2 (determination of control rod OPERABILITY by movement), if a control rod(s) is discovered to be immovable, but remains trippable and aligned, the control rod(s) is considered to be OPERABLE. At any time, if a control rod(s) is immovable, a determination of the trippability (OPERABILITY) of the control rod(s) must be made, and appropriate action taken.

SR 3.1.5.3

Verification of rod drop times allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. Measuring rod drop times prior to reactor criticality, after initial fuel loading and reactor vessel head removal, ensures that the reactor internals and rod drive mechanism will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect control rod motion or drop time. This testing is performed with all RCPs operating and the average moderator temperature ≥ 551°F to simulate a reactor trip under actual conditions.

This Surveillance is performed prior to initial criticality and during a plant outage, due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance were performed with the reactor at power.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 10, "Reactor Design," and General Design Criterion 26, "Reactivity Control System Redundancy and Capability."

2. Title 10, Code of Federal Regulations, Part 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors."

3. Watts Bar FSAR, Section 15.0, "Accident Analyses."

4. Watts Bar FSAR, Section 15.2.3, "Rod Cluster Control Assembly Misalignment."

5. Watts Bar FSAR, Section 15.4.2, "Major Secondary System Pipe Rupture."

6. Watts Bar FSAR, Section 15.3.6, "Single Rod Cluster Control Assembly Withdrawal at Full Power."

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Shutdown Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available ejected rod worth, SDM and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Capability," and GDC 28, "Reactivity Limits" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control (Shutdown Banks C and D have only one group each). A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. Except for Shutdown Banks C and D, a bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and four shutdown banks. See LCO 3.1.5, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.8, "Rod Position Indication," for position indication requirements.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally automatically controlled by the Rod Control System, but they can also be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating). The control banks must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power operations.

(continued)

BASES

BACKGROUND (continued)

Hence, they are not capable of adding a large amount of positive reactivity. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity changes associated with large changes in RCS temperature. The design calculations are performed with the assumption that the shutdown banks are withdrawn first. The shutdown banks are controlled manually by the control room operator. During normal unit operation, the shutdown banks are either fully withdrawn or fully inserted. The shutdown banks must be completely withdrawn from the core, prior to withdrawing any control banks during an approach to criticality. The shutdown banks can be fully withdrawn without the core going critical. This provides available negative reactivity in the event of boration errors. The shutdown banks are then left in this position until the reactor is shut down. They add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

APPLICABLE SAFETY ANALYSES

On a reactor trip, all RCCAs (shutdown banks and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown banks shall be at or above their insertion limits and available to insert the maximum amount of negative reactivity on a reactor trip signal. The control banks may be partially inserted in the core, as allowed by LCO 3.1.7, "Control Bank Insertion Limits." The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM) - T_{avg} > 200°F," and LCO 3.1.2, "SHUTDOWN MARGIN (SDM) - T_{avg} ≤ 200°F") following a reactor trip from full power. The combination of control banks and shutdown banks (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power, and to maintain the required SDM at rated no load temperature (Ref. 3).

The acceptance criteria for addressing shutdown and control rod bank insertion limits and inoperability or misalignment is that:

a. There be no violations of:

   1. specified acceptable fuel design limits, or

   2. RCS pressure boundary integrity; and

b. The core remains subcritical after accident transients other than a main steam line break (MSLB).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

As such, the shutdown bank insertion limits affect safety analysis involving core reactivity and SDM (Ref. 3).

The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and, as such, satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

The shutdown bank insertion limits are defined in the COLR.

APPLICABILITY

The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. The applicability in MODE 2 begins prior to initial control bank withdrawal, during an approach to criticality, and continues throughout MODE 2, until all control bank rods are again fully inserted by reactor trip or by shutdown. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. The shutdown banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. Refer to LCO 3.1.1 and LCO 3.1.2 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

The Applicability requirements have been modified by a Note indicating the LCO requirement is suspended during SR 3.1.5.2. This SR verifies the freedom of the rods to move, and requires the shutdown bank to move below the LCO limits, which would normally violate the LCO.

BASES (continued)

ACTIONS

A.1.1, A.1.2 and A.2

When one or more shutdown banks is not within insertion limits, 2 hours is allowed to restore the shutdown banks to within the insertion limits. This is necessary because the available SDM may be significantly reduced, with one or more of the shutdown banks not within their insertion limits. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (See LCO 3.1.1.). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the Bases for SR 3.1.1.1.

The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

B.1

If the shutdown banks cannot be restored to within their insertion limits within 2 hours, the unit must be brought to a MODE where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

Verification that the shutdown banks are within their insertion limits prior to an approach to criticality ensures that when the reactor is critical, or being taken critical, the shutdown banks will be available to shut down the reactor, and the required SDM will be maintained following a reactor trip. This SR and Frequency ensure that the shutdown banks are withdrawn before the control banks are withdrawn during a unit startup.

Since the shutdown banks are positioned manually by the control room operator, a verification of shutdown bank position at a Frequency of 12 hours, after the reactor is taken critical, is adequate to ensure that they are within their insertion limits. Also, the 12-hour Frequency takes into account other information available in the control room for the purpose of monitoring the status of shutdown rods.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 10, "Reactor Design," General Design Criterion 26, "Reactivity Control System Redundancy and Capability," and General Design Criterion 28, "Reactivity Limits."

2. Title 10, Code of Federal Regulations, Part 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors."

3. Watts Bar FSAR, Section 15.0, "Accident Analyses."

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Control Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available ejected rod worth, SDM, and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are 10 CFR 50, Appendix A, GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Capability," and GDC 28, "Reactivity Limits" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control (Shutdown Banks C and D have only one group each). A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. Except for Shutdown Banks C and D, a bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. There are four control banks and four shutdown banks. See LCO 3.1.5, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.8, "Rod Position Indication," for position indication requirements.

The control bank insertion limits are specified in the COLR. An example is provided for information only in Figure B 3.1.7-1. The control banks are required to be at or above the insertion limit lines.

(continued)

BASES

BACKGROUND (continued)

Figure B 3.1.7-1 also indicates how the control banks are moved in an overlap pattern. Overlap is the distance traveled together by two control banks. The predetermined position of control bank C, at which control bank D will begin to move with bank C on a withdrawal, as an example may be at 128 steps. Therefore, in this example, control bank C overlaps control bank D from 128 steps to the fully withdrawn position for control bank C. The fully withdrawn position and predetermined overlap positions are defined in the COLR.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally controlled automatically by the Rod Control System, but can also be manually controlled. They are capable of adding reactivity very quickly (compared to borating or diluting).

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.5, LCO 3.1.6, "Shutdown Bank Insertion Limits," LCO 3.1.7, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits ensure the required SDM is maintained.

Operation within the subject LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Trip System (RTS) trip function.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The shutdown and control bank insertion limits, AFD, and QPTR LCOs are required to prevent power distributions that could result in fuel cladding failures in the event of a LOCA, loss of flow, ejected rod, or other accident requiring termination by an RTS trip function.

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that:

a. There be no violations of:

   1. specified acceptable fuel design limits, or

   2. Reactor Coolant System pressure boundary integrity; and

b. The core remains subcritical after accident transients other than a main steam line break (MSLB).

As such, the shutdown and control bank insertion limits affect safety analysis involving core reactivity and power distributions (Ref. 3 through 13).

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes the maximum worth RCCA remains fully withdrawn upon trip (Ref. 5, 6, 8 and 11).

Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worths.

The control and shutdown bank insertion limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 3 through 13).

The insertion limits satisfy Criterion 2 of 10CFR 50.36(c)(2)(ii), in that they are initial conditions assumed in the safety analysis.

BASES (continued)

LCO

The limits on control banks sequence, overlap, and physical insertion, as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is maintained, and ensuring adequate negative reactivity insertion is available on trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion.

APPLICABILITY

The control bank sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2 with $k_{eff} \geq 1.0$. These limits must be maintained, since they preserve the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions. Applicability in MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

The applicability requirements have been modified by a Note indicating the LCO requirements are suspended during the performance of SR 3.1.5.2. This SR verifies the freedom of the rods to move, and requires the control bank to move below the LCO limits, which would violate the LCO.

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2

When the control banks are outside the acceptable insertion limits, they must be restored to within those limits. This restoration can occur in two ways:

a. Reducing power to be consistent with rod position; or

b. Moving rods to be consistent with power.

Also, verification of SDM or initiation of boration to regain SDM is required within 1 hour, since the SDM in MODES 1 and 2 normally ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM) - T_{avg} > 200°F") has been upset. If control banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the Bases for SR 3.1.1.1.

(continued)

BASES

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2 (continued)

Similarly, if the control banks are found to be out of sequence or in the wrong overlap configuration, they must be restored to meet the limits.

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the simultaneous occurrence of either a LOCA, loss of flow accident, ejected rod accident, or other accident during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability.

The allowed Completion Time of 2 hours for restoring the banks to within the insertion, sequence, and overlap limits provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

C.1

If Required Actions A.1 and A.2, or B.1 and B.2 cannot be completed within the associated Completion Times, the plant must be brought to MODE 3, where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits.

The estimated critical position (ECP) depends upon a number of factors, one of which is xenon concentration. If the ECP was calculated long before criticality, xenon concentration could change to make the ECP substantially in error. Conversely, determining the ECP immediately before criticality could be an unnecessary burden. There are a number of unit parameters requiring operator attention at that point. Performing the ECP calculation within 4 hours prior to criticality avoids a large error from changes in xenon concentration, but allows the operator some flexibility to schedule the ECP calculation with other startup activities.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.2

With an OPERABLE bank insertion limit monitor, verification of the control bank insertion limits at a Frequency of 12 hours is sufficient to ensure OPERABILITY of the bank insertion limit monitor and to detect control banks that may be approaching the insertion limits since, normally, very little rod motion occurs in 12 hours. If the insertion limit monitor becomes inoperable, verification of the control bank position at a Frequency of 4 hours is sufficient to detect control banks that may be approaching the insertion limits.

SR 3.1.7.3

When control banks are maintained within their insertion limits as checked by SR 3.1.7.2 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. A Frequency of 12 hours is consistent with the insertion limit check above in SR 3.1.7.2.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 10, "Reactor Design," General Design Criterion 26, "Reactivity Control System Redundancy and Capability," and General Design Criterion 28, "Reactivity Limits."

2. Title 10, Code of Federal Regulations, Part 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors."

3. Watts Bar FSAR, Section 15.2.1, "Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical Condition."

4. Watts Bar FSAR, Section 15.2.2, "Uncontrolled Rod Cluster Control Assembly Bank Withdrawal At Power."

5. Watts Bar FSAR, Section 15.2.3, "Rod Cluster Control Assembly Misalignment."

6. Watts Bar FSAR, Section 15.2.4, "Uncontrolled Boron Dilution."

7. Watts Bar FSAR, Section 15.2.5, "Partial Loss of Forced Reactor Coolant Flow."

(continued)

BASES

REFERENCES (continued)

8. Watts Bar FSAR, Section 15.2.13, "Accidental Depressurization of the Main Steam System."

9. Watts Bar FSAR, Section 15.3.4, "Complete Loss of Forced Reactor Coolant Flow."

10. Watts Bar FSAR, Section 15.3.6, "Single Rod Cluster Control Assembly Withdrawal At Full Power."

11. Watts Bar FSAR, Section 15.4.2.1, "Major Rupture of Main Steam Line."

12. Watts Bar FSAR, Section 15.4.4, "Single Reactor Coolant Pump Locked Rotor."

13. Watts Bar FSAR, Section 15.4.6, "Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)."

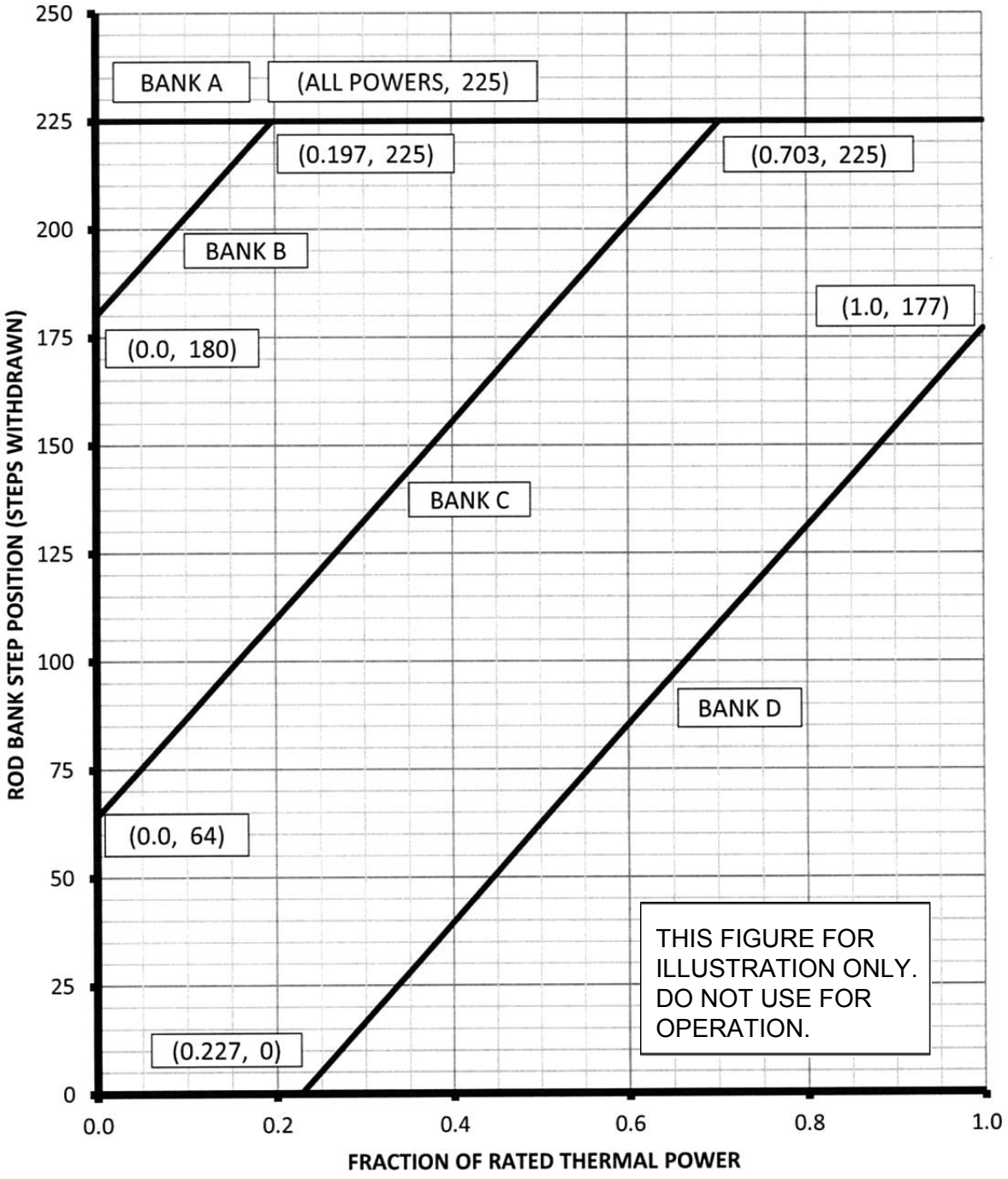


Figure B 3.1.7-1 (page 1 of 1)
Control Bank Insertion vs. Percent RTP

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 Rod Position Indication

BASES

BACKGROUND

According to GDC 13 (Ref. 1), instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. LCO 3.1.8 is required to ensure OPERABILITY of the control rod position indicators to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits.

The OPERABILITY, including position indication, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM. Rod position indication is required to assess OPERABILITY and misalignment.

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms. The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control (Shutdown Banks C and D have only one group each).

The axial position of shutdown rods and control rods are determined by two separate and independent systems: the Bank Demand Position Indication System (commonly called group step counters) and the Rod Position Indication (RPI) System.

(continued)

BASES

BACKGROUND (continued)

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The RPI System provides an accurate indication of actual control rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube with a center-to-center distance of 3.75 inches, which is 6 steps. The normal indication accuracy of the RPI System is ± 6 steps (± 3.75 inches), and the maximum uncertainty is ± 12 steps (± 7.5 inches). With an indicated deviation of 12 steps between the group step counter and RPI, the maximum deviation between actual rod position and the demand position could be 24 steps, or 15 inches.

The Power Distribution Monitoring System (PDMS) as controlled by Technical Requirements Manual Section 3.3.3 develops a detailed three dimensional power distribution via its nodal code coupled with updates from plant instrumentation, including the fixed incore detectors. The monitored power distribution is compared to the reference power distribution corresponding to all control rods properly aligned. Agreement between the two power distributions can be used to indirectly verify the control rod is aligned.

APPLICABLE SAFETY ANALYSES

Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2 through 12), with control or shutdown rods operating outside their limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod worth, and with minimum SDM (LCO 3.1.6, "Shutdown Bank Insertion Limits," and LCO 3.1.7, "Control Bank Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.5, "Rod Group Alignment Limits"). Control rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The control rod position indicator channels satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii). The control rod position indicators monitor control rod position, which is an initial condition of the accident.

LCO

LCO 3.1.8 specifies that the RPI System and the Bank Demand Position Indication System be OPERABLE for all control rods. For the control rod position indicators to be OPERABLE requires meeting the SR of the LCO and the following:

a. The RPI System indicates within 12 steps of the group step counter demand position as required by LCO 3.1.5, "Rod Group Alignment Limits;"

b. For the RPI System there are no failed coils; and

c. The Bank Demand Indication System has been calibrated either in the fully inserted position or to the RPI System.

The 12 step agreement limit between the Bank Demand Position Indication System and the RPI System indicates that the Bank Demand Position Indication System is adequately calibrated, and can be used for indication of the control rod bank position.

A deviation of less than the allowable limit, given in LCO 3.1.5, in position indication for a single control rod, ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the analysis (that specified control rod group insertion limits).

These requirements ensure that control rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged. OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned control rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

BASES (continued)

APPLICABILITY

The requirements on the RPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.5, LCO 3.1.6, and LCO 3.1.7), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System.

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable rod position indicator per group and each demand position indicator per bank. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

A.1

When one RPI channel per group fails, the position of the rod can still be determined indirectly by use of incore power distribution measurement information. Incore power distribution measurement information is obtained from an OPERABLE Power Distribution Monitoring System (PDMS) (Ref. 15). Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Action of B.1 or B.2 below is required. Therefore, verification of rod position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

A.2.1, A.2.2

The control rod drive mechanism (a portion of the rod control system) consists of four separate subassemblies; 1) the pressure vessel, 2) the coil stack assembly, 3) the latch assembly, and 4) the drive rod assembly. The coil stack assembly contains three operating coils; 1) the stationary gripper coil, 2) the moveable gripper coil, and 3) the lift coil. In support of Actions A.2.1 and A.2.2, a Temporary Alteration (TA) to the configuration of the plant is implemented to provide instrumentation for the monitoring of the rod control system parameters in the Main Control Room. The TA creates a circuit that monitors the operation and timing of the lift coil and the stationary gripper coil. Additional details regarding the TA are provided in the FSAR (Ref. 14).

(continued)

BASES

ACTIONS

A.2.1, A.2.2 (continued)

Required Actions A.2.1 and A.1 are essentially the same. Therefore, the discussion provided above for Required Action A.1 applies to Required Action A.2.1. The options provided by Required Actions A.2.1 and A.2.2 allow for continued operation in a situation where the component causing the RPI to be inoperable is inaccessible due to operating conditions (adverse radiological or temperature environment). In this situation, repair of the RPI cannot occur until the unit is in an operating MODE that allows access to the failed components.

In addition to the initial 8 hour verification, Required Action A.2.1 also requires the following for the rod with the failed RPI:

1. Verification of the position of the rod indirectly every 31 days using the PDMS.

2. Verification of the position of the rod indirectly using the PDMS within 8 hours of the performance of Required Action A.2.2 whenever there is an indication of unintended rod movement based on the parameters of the rod control system.

Required Action A.2.2 is in lieu of the verification of the position of the rod indirectly using the PDMS every 8 hours as required by Required Action A.1. Once the position of the rod with the failed RPI is confirmed through the use of the PDMS in accordance with Required Action A.2.1, the parameters of the rod control system must be monitored until the failed RPI is repaired. Should the review of the rod control system parameters indicate unintended movement of the rod, the position of the rod must be verified within 8 hours in accordance with Required Action A.2.1. Should there be unintended movement of the rod with the failed RPI, an alarm will be received. Alarms will also be received if the rod steps in a direction other than what was demanded, and if the circuitry of the TA fails. Receipt of any alarm requires the verification of the position of the rod in accordance with Required Action A.2.1.

Required Actions A.2.1, A.2.2 and A.2.3 are modified by a note. The note clarifies that rod position monitoring by Required Actions A.2.1 and A.2.2 shall only be applied to one rod with an inoperable RPI and shall only be allowed until the end of the current cycle. Further, Required Actions A.2.1, A.2.2 and A.2.3 shall not be allowed after the plant has been in MODE 5 or other plant condition, for a sufficient period of time, in which the repair of the inoperable RPI(s) could have safely been performed.

(continued)

BASES

ACTIONS

A.2.1, A.2.2 (continued)

As indicated previously, the modifications required for the monitoring of the rod control system will be implemented as a TA. Implementation of the TA includes a review for the impact on plant procedures and training. This ensures that changes are initiated for key issues like the monitoring requirements in the control room, and operator training on the temporary equipment.

A.2.3

Required Action A.2.3 addresses two contingency measures when the TA is utilized:

1. Verification of the position of the rod indirectly with the inoperable RPI by use of the PDMS, whenever the rod is moved greater than 12 steps in one direction.

2. Operation of the unit when THERMAL POWER is less than or equal to 50% RTP.

For the first contingency, the rod group alignment limits of LCO 3.1.5 require that all shutdown and control rods be within 12 steps of their group step counter demand position. The limits on shutdown or control rod alignments ensure that the assumptions in the safety analysis will remain valid and that the assumed reactivity will be available to be inserted for a unit shutdown. Therefore, this conservative measure ensures LCO 3.1.5 is met whenever the rod with the inoperable RPI is moved greater than 12 steps. For the second contingency, the reduction of THERMAL POWER to less than or equal to 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors (Ref. 13). Consistent with LCO 3.0.4 and this action, unit startup and operation to less than or equal to 50% RTP may occur with one RPI per group inoperable. However, prior to escalating THERMAL POWER above 50% RTP, the position of the rod with an inoperable RPI must be verified indirectly by use of the PDMS. Once 100% RTP is achieved, the position of the rod must be re-verified indirectly within 8 hours by use of the PDMS. Monitoring of the rod control system parameters in accordance with Required Action A.2.2 for the rod with an inoperable RPI may resume upon completion of the verification at 100% RTP.

(continued)

BASES

ACTIONS (continued)

A.3

Required Action A.3 applies whenever the TA is not utilized or the position of the rod with an inoperable RPI cannot be verified indirectly. The discussion for Required Action A.2.3 (above) clarified that a reduction of THERMAL POWER to less than or equal to 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors (Ref. 13). The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to less than or equal to 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above. Consistent with LCO 3.0.4 and this action, unit startup and operation to less than or equal to 50% RTP may occur with one RPI per group inoperable. Thermal Power may be escalated to 100% RTP as long as Required Action A.1 is satisfied.

B.1 and B.2

These Required Actions clarify that when one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction, since the position was last determined, the Required Actions of A.1 and A.2 are still appropriate but must be initiated promptly under Required Action B.1 to begin verifying that these rods are still properly positioned, relative to their group positions.

If, within 4 hours, the rod positions have not been verified, THERMAL POWER must be reduced to less than or equal to 50% RTP within 8 hours to avoid undesirable power distributions that could result from continued operation at greater than 50% RTP, if one or more rods are misaligned by more than 24 steps. The allowed Completion Time of 4 hours provides an acceptable period of time to verify the rod positions.

C.1.1 and C.1.2

With one demand position indicator per bank inoperable, the rod positions can be determined by the RPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indicators are OPERABLE and the most withdrawn rod and the least withdrawn rod are less than or equal to 12 steps apart within the allowed Completion Time of once every 8 hours is adequate.

(continued)

BASES

ACTIONS (continued)

C.2

Reduction of THERMAL POWER to less than or equal to 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factor limits (Ref. 13). The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions C.1.1 and C.1.2 or reduce power to less than or equal to 50% RTP.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

Verification that the RPI agrees with the demand position within 12 steps ensures that the RPI is operating correctly.

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 unnecessary plant transients if the SR were performed with the reactor at power. Operating experience has shown these components usually pass the SR when performed at a Frequency of once every 18 months. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 13, "Instrumentation and Control."

2. Watts Bar FSAR, Section 15.2.1, "Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From a Subcritical Condition."

3. Watts Bar FSAR, Section 15.2.2, "Uncontrolled Rod Cluster Control Assembly Bank Withdrawal At Power."

4. Watts Bar FSAR, Section 15.2.3, "Rod Cluster Control Assembly Misalignment."

5. Watts Bar FSAR, Section 15.2.4, "Uncontrolled Boron Dilution."

6. Watts Bar FSAR, Section 15.2.5, "Partial Loss of Forced Reactor Coolant Flow."

7. Watts Bar FSAR, Section 15.2.13, "Accidental Depressurization of the Main Steam System."

8. Watts Bar FSAR, Section 15.3.4, "Complete Loss of Forced Reactor Coolant Flow."

9. Watts Bar FSAR, Section 15.3.6, "Single Rod Cluster Control Assembly Withdrawal At Full Power."

10. Watts Bar FSAR, Section 15.4.2.1, "Major Rupture of Main Steam Line."

11. Watts Bar FSAR, Section 15.4.4, "Single Reactor Coolant Pump Locked Rotor."

12. Watts Bar FSAR, Section 15.4.6, "Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)."

13. Watts Bar FSAR, Section 4.3, "Nuclear Design."

14. Watts Bar FSAR, Section 7.7.1.3.2, “Main Control Room Rod Position Indication.”

15. WCAP-12472-P-A, “BEACON™ Core Monitoring and Operations Support System,” August 1994 (Addendum 2, April 2002).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.9 PHYSICS TESTS Exceptions - MODE 1

BASES

BACKGROUND

The primary purpose of the MODE 1 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow the performance of instrumentation calibration tests and special PHYSICS TESTS. The exceptions to LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)" are most often appropriate for xenon stability tests. The exceptions to LCO 3.1.5, "Rod Group Alignment Limits"; LCO 3.1.6, "Shutdown Bank Insertion Limit"; and LCO 3.1.7, "Control Bank Insertion Limits," may be required in the event that it is necessary or desirable to do special PHYSICS TESTS involving abnormal rod or bank configurations.

Section XI of 10 CFR 50, Appendix B (Ref. 1), requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the plant. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program are to (Ref. 3):

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in the design and analysis;

c. Verify the assumptions used to predict unit response;

d. Ensure that installation of equipment at the facility has been accomplished, in accordance with the design; and

e. Verify that the operating and emergency procedures are adequate.

(continued)

BASES

BACKGROUND (continued)

To accomplish these objectives, testing is performed prior to initial criticality; during startup, low power, power ascension, and at power operation. The PHYSICS TESTS for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions, and that the core can be operated as designed.

PHYSICS TESTS procedures are written and approved in accordance with established formats. The procedures include all information necessary to permit a detailed execution of the testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures, and test results are approved prior to continued power escalation and long term power operation.

Typical PHYSICS TESTS for reload fuel cycles (Ref. 4) in MODE 1 are listed below:

a. Neutron Flux Symmetry;

b. Power Distribution - Intermediate Power;

c. Power Distribution - Full Power; and

d. Critical Boron Concentration - Full Power.

The first test can be performed in either MODE 1 or 2. These and other supplementary tests may be required to calibrate the nuclear instrumentation or to diagnose operational problems. These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance. The Power Distribution - Intermediate Power test can be performed at a stable power level between 40% RTP and 80% RTP. The last two tests are performed at ≥ 90% RTP.

APPLICABLE SAFETY ANALYSES

The fuel is protected by an LCO, which preserves the initial conditions of the core assumed during the safety analyses. The methods for development of the LCO, which are superseded by this LCO, are described in the Westinghouse Reload Safety Evaluation Methodology Report (Ref. 5). The above mentioned PHYSICS TESTS, and other tests that may be required to calibrate nuclear instrumentation or to diagnose operational problems, may require the operating controls or process variables to deviate from their LCO limitations.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Reference 6 defines requirements for initial testing of the facility, including PHYSICS TESTS. Table 14.2-2 (Ref. 6) summarizes the zero, low power, and power tests. Summaries of typical reload fuel cycle PHYSICS TESTS are available in ANSI/ANS-19.6.1 (Ref. 4). Although these PHYSICS TESTS are generally accomplished within the limits for all LCOs, conditions may occur when one or more LCOs must be suspended to make completion of PHYSICS TESTS possible or practical. This is acceptable as long as the fuel design criteria are not violated. When one or more of the requirements specified in:

LCO 3.1.5, "Rod Group Alignment Limits";

LCO 3.1.6, "Shutdown Bank Insertion Limits";

LCO 3.1.7, "Control Bank Insertion Limits";

LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; or

LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)"

are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the requirements of LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)," and LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)," are satisfied, power level is maintained ≤ 85% RTP, and SDM is ≥ 1.6% Δk/k. Therefore, LCO 3.1.9 requires surveillance of the hot channel factors and SDM to verify that their limits are not being exceeded.

PHYSICS TESTS include measurements of core nuclear parameters or the exercise of control components that affect process variables. Among the process variables involved are AFD and QPTR, which represent initial conditions of the unit safety analyses. Also involved are the movable control components (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR.

PHYSICS TESTS meet the criteria for inclusion in the Technical Specifications, since the component and process variable LCOs suspended during PHYSICS TESTS meet Criteria 1, 2, and 3 of 10 CFR 50.36(c)(2)(ii).

Reference 7 allows special test exceptions to be included as part of the LCO that they affect. However, it was decided to retain this special test exception as a separate LCO because it was less cumbersome and provided additional clarity.

BASES (continued)

LCO

This LCO allows selected control rods and shutdown rods to be positioned outside their specified alignment limits and insertion limits to conduct PHYSICS TESTS in MODE 1, to verify certain core physics parameters. The power level is limited to ≤ 85% RTP and the power range neutron flux trip setpoint is set at 10% RTP above the PHYSICS TESTS power level with a maximum setting of 90% RTP. Violation of LCO 3.1.5, LCO 3.1.6, LCO 3.1.7, LCO 3.2.3, or LCO 3.2.4, during the performance of PHYSICS TESTS does not pose any threat to the integrity of the fuel as long as the requirements of LCO 3.2.1 and LCO 3.2.2 are satisfied and provided:

a. THERMAL POWER is maintained ≤ 85% RTP;

b. Power Range Neutron Flux - High trip setpoints are ≤ 10% RTP above the THERMAL POWER at which the test is performed, with a maximum setting of 90% RTP; and

c. SDM is ≥ 1.6% $\Delta k/k$.

Operation with THERMAL POWER ≤ 85% RTP during PHYSICS TESTS provides an acceptable thermal margin when one or more of the applicable LCOs is out of specification. The Power Range Neutron Flux - High trip setpoint is reduced so that a similar margin exists between the steady state condition and the trip setpoint that exists during normal operation at RTP.

APPLICABILITY

This LCO is applicable in MODE 1 when performing PHYSICS TESTS. The applicable PHYSICS TESTS are performed at ≤ 85% RTP. Other PHYSICS TESTS are performed at full power but do not require violation of any existing LCO, and therefore do not require a PHYSICS TESTS exception. The PHYSICS TESTS performed in MODE 2 are covered by LCO 3.1.10, "PHYSICS TESTS Exceptions - MODE 2."

BASES (continued)

ACTIONS

A.1 and A.2

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

B.1 and B.2

When THERMAL POWER is > 85% RTP, the only acceptable actions are to reduce THERMAL POWER to ≤ 85% RTP or to suspend the PHYSICS TESTS exceptions. With the PHYSICS TESTS exceptions suspended, the PHYSICS TESTS may proceed if all other LCO requirements are met. Fuel integrity may be challenged with control rods or shutdown rods misaligned and THERMAL POWER > 85% RTP. The allowed Completion Time of 1 hour is reasonable, based on operating experience, for completing the Required Actions in an orderly manner and without challenging plant systems. This Completion Time is also consistent with the Required Actions of the LCOs that are suspended by the PHYSICS TESTS.

C.1 and C.2

When the Power Range Neutron Flux - High trip setpoints are > 10% RTP above the PHYSICS TESTS power level or > 90% RTP, the Reactor Trip System (RTS) may not provide the required degree of core protection if the trip setpoint is greater than the specified value.

The only acceptable actions are to restore the trip setpoint to the allowed value or to suspend the performance of the PHYSICS TESTS exceptions. The Completion Time of 1 hour is based on the practical amount of time it may take to restore the Neutron Flux - High trip setpoints to the correct value, consistent with operating plant safety. This Completion Time is consistent with the Required Actions of the LCOs that are suspended by the PHYSICS TESTS.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.9.1

Verification that the THERMAL POWER level is ≤ 85% RTP will ensure that the required core protection is provided during the performance of PHYSICS TESTS. Control of the reactor power level is a vital parameter and is closely monitored during the performance of PHYSICS TESTS. A Frequency of 1 hour is sufficient for ensuring that the power level does not exceed the limit.

SR 3.1.9.2

Verification of the Power Range Neutron Flux - High trip setpoints within 8 hours prior to initiation of the PHYSICS TESTS will ensure that the RTS is properly set to perform PHYSICS TESTS.

SR 3.1.9.3

The performance of SR 3.2.1.1 and SR 3.2.2.1 measures the core $F_Q(Z)$ and the $F^N_{\Delta H}$, respectively. If the requirements of these LCOs are met, the core has adequate protection from exceeding its design limits, while other LCO requirements are suspended. The Frequency of 12 hours is based on operating experience and the practical amount of time that it may take to obtain an incore power distribution measurement and calculate the hot channel factors.

SR 3.1.9.4

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. Reactor Coolant System (RCS) boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Design isothermal temperature coefficient (ITC).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.9.4 (continued)

Using the ITC accounts for Doppler reactivity in the calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and on the low probability of an accident without the required SDM.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants."

2. Title 10, Code of Federal Regulations, Part 50.59, "Changes, Tests, and Experiments."

3. Regulatory Guide 1.68, Revision 2, "Initial Test Programs for Water-Cooled Nuclear Power Plants," August 1978.

4. ANSI/ANS-19.6.1, "Reload Startup PHYSICS TESTS for Pressurized Water Reactors," American National Standards Institute.

5. WCAP-9272-P-A, "Westinghouse Reload Safety Evaluation Methodology Report," July 1985.

6. Watts Bar FSAR, Section 14.2, "Test Program."

7. WCAP-11618, "MERITS Program - Phase II, Task 5, Criteria Application," dated November 1987, including Addendum 1, April 1989.

8. WCAP-12472-P-A, “BEACON™ Core Monitoring and Operations Support System,” August 1994 (Addendum 2, April 2002).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.10 PHYSICS TESTS Exceptions - MODE 2

BASES

BACKGROUND

The primary purpose of the MODE 2 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow certain PHYSICS TESTS to be performed.

Section XI of 10 CFR 50, Appendix B (Ref. 1) requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the plant. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program are to (Ref. 3):

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in the design and analysis;

c. Verify the assumptions used to predict unit response;

d. Ensure that installation of equipment in the facility has been accomplished in accordance with the design; and

e. Verify that the operating and emergency procedures are adequate.

To accomplish these objectives, testing is performed prior to initial criticality, during startup, during low power operations, during power ascension and at high power. The PHYSICS TESTS for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions and that the core can be operated as designed.

(continued)

BASES

BACKGROUND (continued)

PHYSICS TESTS procedures are written and approved in accordance with established formats. The procedures include all information necessary to permit a detailed execution of the testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures and test results are approved prior to continued power escalation and long term power operation.

Typical PHYSICS TESTS for reload fuel cycles (Ref. 4) in MODE 2 are listed below:

a. Critical Boron Concentration - Control Rods Withdrawn;

b. Control Rod Bank Worth;

c. Isothermal Temperature Coefficient (ITC); and

d. Neutron Flux Symmetry.

The last test can be performed in either MODE 1 or 2. These and other supplementary tests may be required to calibrate the nuclear instrumentation or to diagnose operational problems. These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance.

APPLICABLE SAFETY ANALYSES

The fuel is protected by LCOs that preserve the initial conditions of the core assumed during the safety analyses. The methods for development of the LCOs that are excepted by this LCO are described in the Westinghouse Reload Safety Evaluation Methodology Report (Ref. 5). The above mentioned PHYSICS TESTS, and other tests that may be required to calibrate nuclear instrumentation or to diagnose operational problems, may require the operating control or process variables to deviate from their LCO limitations.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The FSAR defines requirements for initial testing of the facility, including PHYSICS TESTS. Table 14.2-2 summarizes the zero, low power, and power tests for the initial plant startup. Summaries of typical reload fuel cycle PHYSICS TESTS are available in ANSI/ANS-19.6.1 (Ref. 4). Although these PHYSICS TESTS are generally accomplished within the limits for all LCOs, conditions may occur when one or more LCOs must be suspended to make completion of PHYSICS TESTS possible or practical. This is acceptable as long as the fuel design criteria are not violated. When one or more of the requirements specified in LCO 3.1.4, "Moderator Temperature Coefficient (MTC)," LCO 3.1.5, LCO 3.1.6, LCO 3.1.7, and LCO 3.4.2 are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the power level is limited to ≤ 5% RTP, the reactor coolant temperature is kept ≥ 541°F, and SDM is ≥ 1.6% $\Delta k/k$.

The PHYSICS TESTS include measurement of core nuclear parameters or the exercise of control components that affect process variables. Among the process variables involved are AFD and QPTR, which represent initial conditions of the unit safety analyses. Also involved are the movable control components (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR. PHYSICS TESTS meet the criteria for inclusion in the Technical Specifications, since the components and process variable LCOs suspended during PHYSICS TESTS meet Criteria 1, 2, and 3 of 10 CFR 50.36(c)(2)(ii).

Reference 6 allows special test exceptions (STEs) to be included as part of the LCO that they affect. It was decided, however, to retain this STE as a separate LCO because it was less cumbersome and provided additional clarity.

LCO

This LCO allows the reactor parameters of MTC and minimum temperature for criticality to be outside their specified limits. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. One Power Range Neutron Flux channel may be bypassed, reducing the number of required channels from "4" to "3." Operation beyond specified limits is permitted for the purpose of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

(continued)

BASES

LCO (continued)

The requirements of LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, LCO 3.1.7, and LCO 3.4.2 may be suspended and the number of required channels for LCO 3.3.1, "RTS Instrumentation," Functions 2, 3, 6, and 16.e, may be reduced to "3" required channels during the performance of PHYSICS TESTS provided:

a. RCS lowest loop average temperature is ≥ 541°F; and

b. SDM is ≥ 1.6% Δ k/k.

APPLICABILITY

This LCO is applicable in MODE 2 when performing low power PHYSICS TESTS. The applicable PHYSICS TESTS are performed in MODE 2 at HZP. Other PHYSICS TESTS are performed in MODE 1 and are addressed in LCO 3.1.9, "PHYSICS TESTS Exceptions - MODE 1."

ACTIONS

A.1 and A.2

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

B.1

When THERMAL POWER is >5% RTP, the only acceptable action is to open the reactor trip breakers (RTBs) to prevent operation of the reactor beyond its design limits. Immediately opening the RTBs will shut down the reactor and prevent operation of the reactor outside of its design limits.

(continued)

BASES

ACTIONS (continued)

C.1

When the RCS lowest T_{avg} is < 541°F, the appropriate action is to restore T_{avg} to within its specified limit. The allowed Completion Time of 15 minutes provides time for restoring T_{avg} to within limits without allowing the plant to remain in an unacceptable condition for an extended period of time. Operation with the reactor critical and with temperature below 541°F could violate the assumptions for accidents analyzed in the safety analyses.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within an additional 15 minutes. The Completion Time of 15 additional minutes is reasonable, based on operating experience, for reaching MODE 3 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.10.1

The power range and intermediate range neutron detectors must be verified to be OPERABLE in MODE 2 by LCO 3.3.1, “Reactor Trip System (RTS) Instrumentation.” A CHANNEL OPERATIONAL TEST is performed on each power range and intermediate range channel prior to initiation of the PHYSICS TESTS. This will ensure that the RTS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS.

SR 3.1.10.2

Verification that the RCS lowest loop T_{avg} is ≥ 541°F (value does not account for instrument error) will ensure that the unit is not operating in a condition that could invalidate the safety analyses. Verification of the RCS temperature at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.10.3

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Design isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and on the low probability of an accident occurring without the required SDM.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix B, “Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants.”

2. Title 10, Code of Federal Regulations, Part 50.59, “Changes, Tests and Experiments.”

3. Regulatory Guide 1.68, Revision 2, “Initial Test Programs for Water-Cooled Nuclear Power Plants,” August 1978.

4. ANSI/ANS-19.6.1, “Reload Startup Physics Tests for Pressurized Water Reactors,” American National Standards Institute.

5. WCAP-9272-P-A, “Westinghouse Reload Safety Evaluation Methodology Report,” July 1985.

6. WCAP-11618, “MERITS Program - Phase II, Task 5, Criteria Application,” dated November 1987, including Addendum 1, April 1989.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$)

BASES

BACKGROUND

The purpose of the limits on the values of $F_Q(Z)$ is to limit the local (i.e., pellet) peak power density. The value of $F_Q(Z)$ varies along the axial height (Z) of the core.

$F_Q(Z)$ is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and fuel rod dimensions adjusted for uncertainty. Therefore, $F_Q(Z)$ is a measure of the peak fuel pellet power within the reactor core.

During power operation, the global power distribution is limited by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which are directly and continuously measured process variables. These LCOs, along with LCO 3.1.7, "Control Bank Insertion Limits," maintain the core limits on power distributions on a continuous basis.

$F_Q(Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution.

$F_Q(Z)$ is measured periodically using the Power Distribution Monitoring System (PDMS). These measurements are generally taken with the core at or near steady state conditions.

Using the measured three dimensional power distributions, it is possible to derive a measured value for $F_Q(Z)$. However, because this value represents a steady state condition, it does not include the variations in the value of $F_Q(Z)$ that are present during nonequilibrium situations, such as load following.

To account for these possible variations, the steady state value of $F_Q(Z)$ is adjusted by an elevation dependent factor that accounts for the calculated worst case transient conditions.

Core monitoring and control under nonsteady state conditions are accomplished by operating the core within the limits of the appropriate LCOs, including the limits on AFD, QPTR, and control rod insertion.

BASES (continued)

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a loss of coolant accident (LOCA), the peak cladding temperature must not exceed 2200°F for small breaks, and there must be a high level of probability that the peak cladding temperature does not exceed 2200°F for large breaks (Ref. 1);

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a departure from nucleate boiling (DNB) condition;

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm (Ref. 2); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

Limits on $F_Q(Z)$ ensure that the value of the initial total peaking factor assumed in the accident analyses remains valid. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, the peak cladding temperature is typically most limiting.

$F_Q(Z)$ limits assumed in the LOCA analysis are typically limiting relative to (i.e., lower than) the $F_Q(Z)$ limit assumed in safety analyses for other postulated accidents. Therefore, this LCO provides conservative limits for other postulated accidents.

$F_Q(Z)$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The Heat Flux Hot Channel Factor, $F_Q(Z)$, shall be limited by the following relationships:

$$F_Q(Z) \leq \frac{CFQ}{P} K(Z) \quad \text{for } P > 0.5$$

$$F_Q \leq \frac{CFQ}{0.5} K(Z) \qquad \text{for } P \leq 0.5$$

where: CFQ is the $F_Q(Z)$ limit at RTP provided in the COLR,

K(Z) is the normalized $F_Q(Z)$ as a function of core height provided in the COLR, and

$$P = \frac{\text{THERMAL POWER}}{\text{RTP}}$$

The actual values of CFQ and K(Z) are given in the COLR; however, CFQ is normally a number on the order of 2.5, and K(Z) is a function that looks like the one provided in Figure B 3.2.1-1.

For Relaxed Axial Offset Control operation, $F_Q(Z)$ is approximated by $F_Q^C(Z)$ and $F_Q^W(Z)$. Thus, both $F_Q^C(Z)$ and $F_Q^W(Z)$ must meet the preceding limits on $F_Q(Z)$.

An $F_Q^C(Z)$ evaluation requires obtaining an incore power distribution measurement in MODE 1. The measured value, $F_Q^M(Z)$, of $F_Q(Z)$ is obtained from the incore power distribution measurement and then corrected for fuel manufacturing tolerances and measurement uncertainty.

(continued)

BASES

LCO (continued)

Using the PDMS to obtain the incore power distribution measurement:

$$F_Q^C = 1.03\, F_Q^M(Z)\left(1+\frac{U_Q}{100}\right)$$

where 1.03 is the factor that accounts for the fuel manufacturing tolerances and the factor $(1+U_Q/100)$, which accounts for measurement uncertainty, is calculated and applied automatically by the BEACON™ software (Ref. 4).

$F_Q^C(Z)$ is an approximation of the steady state $F_Q(Z)$.

The expression for $F_Q^W(Z)$ is:

$F_Q^W(Z) = F_Q^C(Z)\, W(Z)/P$ for $P > 0.5$

$F_Q^W(Z) = F_Q^C(Z)\, W(Z)/0.5$ for $P \leq 0.5$

where W(Z) is a cycle dependent function that accounts for power distribution transients encountered during normal operation. W(Z) is included in the COLR.

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200°F during a small break LOCA, and assures with a high level of probability that the peak cladding temperature does not exceed 2200°F for large breaks (Ref. 1).

This LCO requires operation within the bounds assumed in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within the LOCA $F_Q(Z)$ limits. If $F_Q(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required.

Violating the LCO limits for $F_Q(Z)$ produces unacceptable consequences if a design basis event occurs while $F_Q(Z)$ is outside its specified limits.

APPLICABILITY

The $F_Q(Z)$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power.

BASES (continued)

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q^C(Z)$ exceeds its limit, maintains an acceptable absolute power density. $F_Q^C(Z)$ is $F_Q^M(Z)$ multiplied by a factor accounting for manufacturing tolerances and measurement uncertainties. $F_Q^M(Z)$ is the measured value of $F_Q(Z)$. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time.

A.2

A reduction of the Power Range Neutron Flux - High trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 8 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1.

A.3

Reduction in the Overpower ΔT trip setpoints by ≥ 1% for each 1% by which $F_Q^C(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1.

A.4

Verification that $F_Q^C(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, ensures that core conditions during operation at higher power levels are consistent with safety analyses assumptions.

(continued)

BASES

ACTIONS (continued)

B.1

If it is found that the maximum calculated value of $F_Q(Z)$ that can occur during normal maneuvers, $F_Q^W(Z)$, exceeds its specified limits, there exists a potential for $F_Q^C(Z)$ to become excessively high if a normal operational transient occurs. Reducing the AFD limits by ≥ 1% for each 1% by which $F_Q^W(Z)$ exceeds its limit within the allowed Completion Time of 2 hours, restricts the axial flux distribution such that even if a transient occurred, core peaking factors would be similarly restricted.

B.2.1, B.2.2, B.2.3, and B.2.4

Required Actions B.2.1 through B.2.4 are modified by a Note. The Note clarifies that Required Actions B.2.1, B.2.2, B.2.3, and B.2.4 only apply to measurements performed at greater than or equal to 75% RTP that resulted in $F_Q^W(Z)$ not within limits. In the central core regions, $F_Q^W(Z)$ is limiting at full power. Consequently, operation below 75% RTP will not challenge the LCO limit. SR 3.2.1.2 is required to be performed after achieving equilibrium conditions after exceeding, by 10% RTP, the THERMAL POWER at which $F_Q^W(Z)$ was last verified. This ensures that an appropriate margin assessment will be performed at full power equilibrium conditions. The results of this full power surveillance will be sufficient to determine whether subsequent non-equilibrium operation could challenge the LCO limit.

B.2.1

Reducing the maximum allowable power by ≥ 3% RTP for each 1% by which $F_Q^W(Z)$ exceeds its limit, maintains an acceptable absolute power density. The Completion Time of 4 hours is sufficient considering the small likelihood of a power distribution transient followed by a severe transient in this time period and the preceding reduction of AFD limits in accordance with Required Action B.1.

B.2.2

A reduction of the Power Range Neutron Flux – High trip setpoints by ≥ 1% for each 1%, the maximum allowable power is reduced in accordance with Required Action B.2.1 is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a power distribution transient followed by a severe transient in this time period and the preceding reduction in maximum allowable power.

(continued)

BASES

ACTIONS (continued)

B.2.3

Reduction in the Overpower ΔT trip setpoints by ≥ 1% for each 1%, the maximum allowable power is reduced in accordance with Required Action B.2.1 is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a power distribution transient followed by a severe transient in this time period and the preceding reduction in maximum allowable power.

B.2.4

Verification that $F_Q^C(Z)$ and $F_Q^W(Z)$ have been restored to within limit, by performing SR 3.2.1.1 and SR 3.2.1.2 prior to increasing THERMAL POWER above the limit imposed by Required Action B.2.1, ensures that core conditions during operation at higher power levels are consistent with safety analyses assumptions.

C.1

If Required Actions A.1 through A.4, or B.1 and B.2.1 through B.2.4, are not met within their associated Completion Times, the plant must be placed in a mode or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 and SR 3.2.1.2 are modified by a Note. The Note applies during the first power ascension after initial fuel loading and a refueling. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map can be obtained. This allowance is modified, however, by one of the Frequency conditions that requires verification that $F_Q^C(Z)$ and $F_Q^W(Z)$ are within their specified limits after a power rise of more than 10% RTP over the THERMAL POWER at which they were last verified to be within specified limits. Because $F_Q^C(Z)$ and $F_Q^W(Z)$ could not have previously been measured in this core, there is a second Frequency condition that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q^C(Z)$ and $F_Q^W(Z)$ is made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F_Q^C(Z)$ and $F_Q^W(Z)$ following a power increase of more than 10%, ensures that they are verified as soon as RTP (or any other level for extended operation) is achieved.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q^C(Z)$ and $F_Q^W(Z)$. The Frequency condition is not intended to require verification of these parameters after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which F_Q was last measured.

SR 3.2.1.1

Verification that $F_Q^C(Z)$ is within its specified limits involves increasing $F_Q^M(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q^C(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from the incore power distribution measurement.

Using the PDMS to obtain the incore power distribution measurement:

$$F_Q^C\ (Z) = \ 1.03\ F_Q^M(Z)\left(1 + \frac{U_Q}{100}\right)$$

where 1.03 is the factor that accounts for the fuel manufacturing tolerances and the factor $(1+U_Q/100)$, which accounts for measurement uncertainty, is calculated and applied automatically by the BEACON™ software (Ref. 4).

The limit with which $F_Q^C(Z)$ is compared varies inversely with power above 50% RTP and directly with a function called K(Z) provided in the COLR.

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F_Q^C(Z)$ limit is met when RTP is achieved, because peaking factors generally decrease as power level is increased.

If THERMAL POWER has been increased by ≥ 10% RTP since the last determination of $F_Q^C(Z)$, another evaluation of this factor is required 12 hours after achieving equilibrium conditions at this higher power level (to ensure that $F_Q^C(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

The Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup because such changes are slow and well controlled when the plant is operated in accordance with the Technical Specifications (TS).

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.1.2

The nuclear design process includes calculations performed to determine that the core can be operated within the $F_Q(Z)$ limits. Because incore power distribution measurements are taken at or near steady state conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the incore power distribution measurement data. These variations are, however, conservatively calculated by considering a wide range of unit maneuvers in normal operation. The maximum peaking factor increase over steady state values, calculated as a function of core elevation, Z, is called W(Z). Multiplying the measured total peaking factor, $F_Q^C(Z)$, by W(Z) and by dividing by P gives the maximum $F_Q(Z)$ calculated to occur in normal operation, $F_Q^W(Z)$. Scaling the W(Z) factors by "1/P" accounts for the possibility that reactor power may be increased prior to the next F_Q surveillance (Ref. 5).

The limit with which $F_Q^W(Z)$ is compared varies inversely with power and directly with the function K(Z) provided in the COLR.

The W(Z) curve is provided in the COLR for discrete core elevations. Incore power distribution measurement results are typically calculated at 30 to 75 core elevations. $F_Q^W(Z)$ evaluations are not applicable for the following axial core regions, measured in percent of core height:

a. Lower core region, from 0 to 10% inclusive; and

b. Upper core region, from 90 to 100% inclusive.

The top and bottom 10% of the core are excluded from the evaluation because of the difficulty of making a precise measurement in these regions.

This Surveillance has been modified by a Note that may require that more frequent surveillances be performed. If $F_Q^W(Z)$ increased by the appropriate factor specified in the COLR is not within limit, then $F_Q(Z)$ is required to be evaluated more frequently, each 7 EFPD. The appropriate factor specified in the COLR bounds the amount $F_Q(Z)$ is expected to increase within the normal surveillance frequency of 31 EFPD. The increased surveillance frequency, 7 EFPD, may be discontinued when two successive F_Q evaluations indicate increasing margin to the limit.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 (continued)

These alternative requirements prevent $F_Q(Z)$ from exceeding its limit for any significant period of time without detection.

Performing the Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F_Q(Z)$ limit is met when RTP is achieved, because peaking factors are generally decreased as power level is increased.

$F_Q(Z)$ is verified at power levels ≥ 10% RTP above the THERMAL POWER of its last verification, 12 hours after achieving equilibrium conditions to ensure that $F_Q(Z)$ is within its limit at higher power levels.

The Surveillance Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup. The Surveillance may be done more frequently if required by the results of $F_Q(Z)$ evaluations.

The Frequency of 31 EFPD is adequate to monitor the change of power distribution because such a change is sufficiently slow, when the plant is operated in accordance with the TS, to preclude adverse peaking factors between 31 day surveillances.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors."

2. Regulatory Guide 1.77, Rev. 0, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized water Reactors," May 1974.

3. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants," GDC 26, "Reactivity Control System Redundancy and Capability."

4. WCAP-12472-P-A, “BEACON™ Core Monitoring and Operations Support System,” August 1994, (Addendum 2, April 2002).

5. Westinghouse Technical Bulletin (TB) 08-4, “F_Q Surveillance at Part Powers,” July 15, 2008.

6. Not used.

7. Westinghouse Nuclear Safety Advisory Letter, NSAL-09-5, Revision 1, “Relaxed Axial Offset Control F_Q Technical Specification Actions,” September 23, 2009.

8. Westinghouse Nuclear Safety Advisory Letter, NSAL-15-1, “Heat Flux Channel Factor Technical Specification Surveillance,” February 3, 2015.

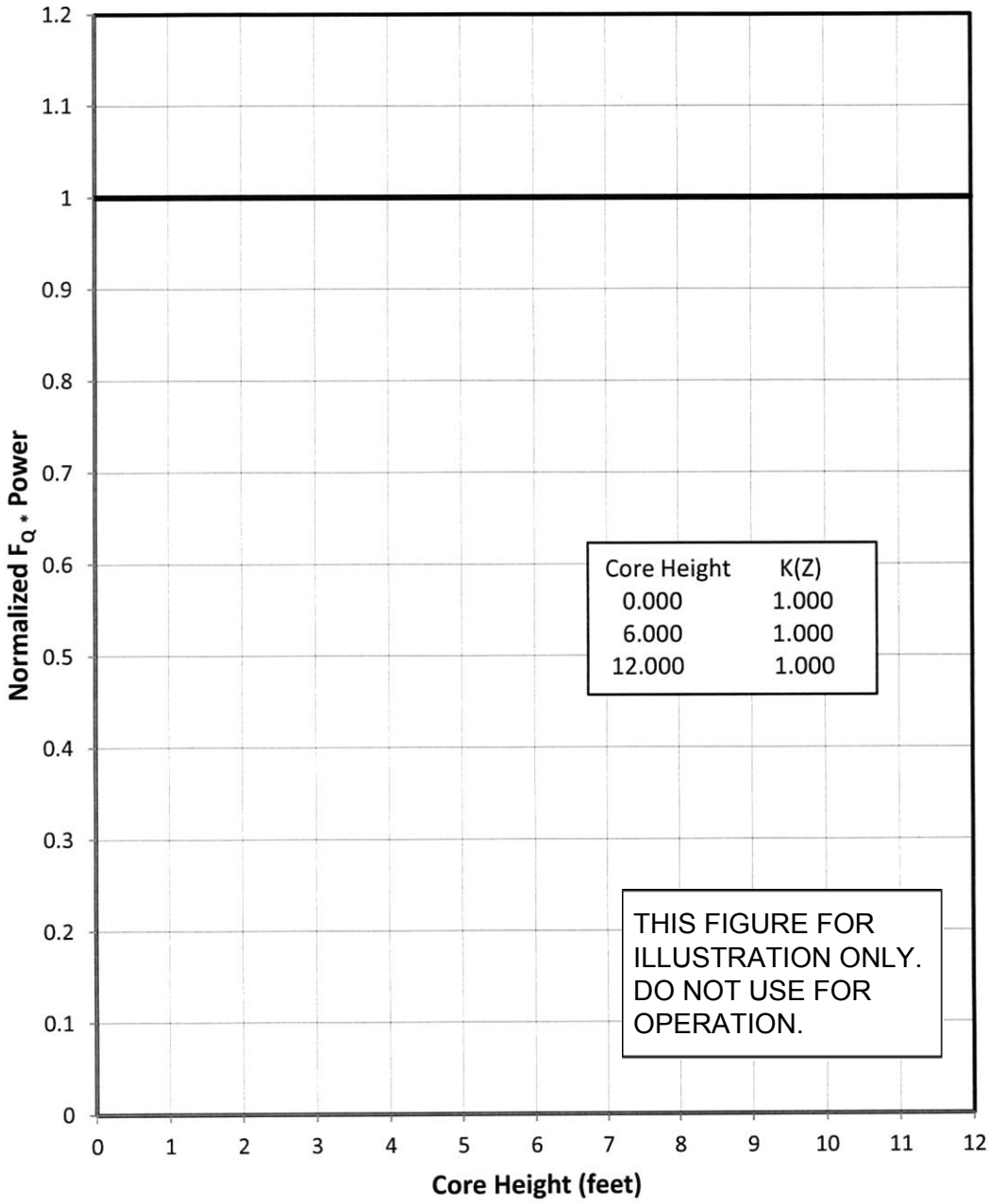


Figure B 3.2.1-1 (page 1 of 1)
K(Z) - Normalized $F_Q(Z)$ as a Function of Core Height

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 Nuclear Enthalpy Rise Hot Channel Factor $F^N_{\Delta H}$

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the power density at any point in the core so that the fuel design criteria are not exceeded and the accident analysis assumptions remain valid. The design limits on local (pellet) and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location during either normal operation or a postulated accident analyzed in the safety analyses.

$F^N_{\Delta H}$ is defined as the ratio of the integral of the linear power along the fuel rod with the highest integrated power to the average integrated fuel rod power. Therefore, $F^N_{\Delta H}$ is a measure of the maximum total power produced in a fuel rod.

$F^N_{\Delta H}$ is sensitive to fuel loading patterns, bank insertion, and fuel burnup. $F^N_{\Delta H}$ typically increases with control bank insertion and typically decreases with fuel burnup.

$F^N_{\Delta H}$ is not directly measurable but is inferred from an incore power distribution measurement obtained with the Power Distribution Monitoring System (PDMS). Specifically, the results of the three dimensional incore power distribution measurement are analyzed by a computer to determine $F^N_{\Delta H}$. This factor is calculated at least every 31 EFPD. However, during power operation, the global power distribution is monitored by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which address directly and continuously measured process variables.

The COLR provides peaking factor limits that ensure that the design basis value of the departure from nucleate boiling (DNB) is met for normal operation, operational transients, and any transient condition arising from events of moderate frequency. The DNB design basis precludes DNB for the hottest fuel rod in the core. All DNB limited transient events are assumed to begin with an $F^N_{\Delta H}$ value that satisfies the LCO requirements.

(continued)

BASES

BACKGROUND (continued)

Operation outside the LCO limits may produce unacceptable consequences if a DNB limiting event occurs. The DNB design basis ensures that there is no overheating of the fuel that results in possible cladding perforation with the release of fission products to the reactor coolant.

APPLICABLE SAFETY ANALYSES

Limits on $F^N_{\Delta H}$ preclude core power distributions that exceed the following fuel design limits:

a. There must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition;

b. During a loss of coolant accident (LOCA), the peak cladding temperature (PCT) must not exceed 2200°F for small breaks, and there must be a high level of probability that the peak cladding temperature does not exceed 2200°F for large breaks (Ref. 3);

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm (Ref. 1); and

d. Fuel design limits required by GDC 26 (Ref. 2) for the condition when control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

For transients that may be DNB limited, $F^N_{\Delta H}$ is a significant core parameter. The limits on $F^N_{\Delta H}$ ensure that the DNB design basis is met for normal operation, operational transients, and any transients arising from events of moderate frequency. The DNB design basis is met by limiting the minimum local DNB heat flux ratio to a value which satisfies the 95/95 criterion for the DNB correlation used. Refer to the Bases for the Reactor Core Safety Limits, B 2.1.1, for a discussion of the applicable DNBR limits. The W-3 Correlation with a DNBR limit of 1.3 is applied in the heated region below the first mixing vane grid. In addition, the W-3 DNB correlation is applied in the analysis of accident conditions where the system pressure is below the range of the WRB-2M correlation for RFA-2 fuel with IFMs. For system pressures in the range of 500 to 1000 psia, the W-3 correlation DNBR limit is 1.45 instead of 1.3.

Application of these criteria provides assurance that the hottest fuel rod in the core does not experience a DNB.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This functionality in $F^N_{\Delta H}$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, any DNB events in which the calculation of the core limits is modeled implicitly use this variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all transients that may be DNB limited are assumed to begin with an initial $F^N_{\Delta H}$ as a function of power level defined by the COLR limit equation.

The LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 3) model $F^N_{\Delta H}$ as well as the Nuclear Heat Flux Hot Channel Factor ($F_Q(Z)$).

The fuel is protected in part by Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid. The following LCOs ensure this: LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," LCO 3.1.7, "Control Bank Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)," and LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)."

$F^N_{\Delta H}$ and $F_Q(Z)$ are measured periodically using the PDMS (Ref. 4). Measurements are generally taken with the core at, or near, steady state conditions. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion Limits.

$F^N_{\Delta H}$ satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR.

The $F^N_{\Delta H}$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least heat removal capability and thus the highest probability for a DNB.

The limiting value of $F^N_{\Delta H}$, described by the equation contained in the COLR, is the design radial peaking factor used in the unit safety analyses.

(continued)

BASES

LCO (continued)

A power multiplication factor in this equation includes an additional margin for higher radial peaking from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of $F^N_{\Delta H}$ is allowed to increase 0.3% for every 1% RTP reduction in THERMAL POWER.

APPLICABILITY

The $F^N_{\Delta H}$ limits must be maintained in MODE 1 to preclude core power distributions from exceeding the fuel design limits for DNBR and PCT. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F^N_{\Delta H}$ in other MODES (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these MODES.

ACTIONS

A.1.1

With $F^N_{\Delta H}$ exceeding its limit, the unit is allowed 4 hours to restore $F^N_{\Delta H}$ to within its limits. This restoration may, for example, involve realigning any misaligned rods or reducing power enough to bring $F^N_{\Delta H}$ within its power dependent limit. When the $F^N_{\Delta H}$ limit is exceeded, the DNBR limit is not likely violated in steady state operation, because events that could significantly perturb the $F^N_{\Delta H}$ value (e.g., static control rod misalignment) are considered in the safety analyses. However, the DNBR limit may be violated if a DNB limiting event occurs. Thus, the allowed Completion Time of 4 hours provides an acceptable time to restore $F^N_{\Delta H}$ to within its limits without allowing the plant to remain in an unacceptable condition for an extended period of time.

Condition A is modified by a Note that requires that Required Actions A.2 and A.3 must be completed whenever Condition A is entered. Thus, if power is not reduced because this Required Action is completed within the 4 hour time period, Required Action A.2 nevertheless requires another measurement and calculation of $F^N_{\Delta H}$ within 24 hours in accordance with SR 3.2.2.1.

However, if power is reduced below 50% RTP, Required Action A.3 requires that another determination of $F^N_{\Delta H}$ must be done prior to exceeding 50% RTP, prior to exceeding 75% RTP, and within 24 hours after reaching or exceeding 95% RTP. In addition, Required Action A.2 is performed if power ascension is delayed past 24 hours.

(continued)

ACTIONS (continued)

A.1.2.1 and A.1.2.2

If the value of $F^N_{\Delta H}$ is not restored to within its specified limit either by adjusting a misaligned rod or by reducing THERMAL POWER, the alternative option is to reduce THERMAL POWER to < 50% RTP in accordance with Required Action A.1.2.1 and reduce the Power Range Neutron Flux-High to ≤ 55% RTP in accordance with Required Action A.1.2.2. Reducing RTP to < 50% RTP increases the DNB margin and does not likely cause the DNBR limit to be violated in steady state operation. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. The allowed Completion Time of 4 hours for Required Action A.1.2.1 is consistent with those allowed for in Required Action A.1.1 and provides an acceptable time to reach the required power level from full power operation without allowing the plant to remain in an unacceptable condition for an extended period of time. The Completion Times of 4 hours for Required Actions A.1.1 and A.1.2.1 are not additive.

The allowed Completion Time of 8 hours to reset the trip setpoints per Required Action A.1.2.2 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and there is no urgent need to reduce the trip setpoints. This is a sensitive operation that may inadvertently trip the Reactor Protection System.

A.2

Once the power level has been reduced to < 50% RTP per Required Action A.1.2.1, an incore power distribution measurement (SR 3.2.2.1) must be obtained and the measured value of $F^N_{\Delta H}$ verified not to exceed the allowed limit at the lower power level. The unit is provided 20 additional hours to perform this task over and above the 4 hours allowed by either Action A.1.1 or Action A.1.2.1. The Completion Time of 24 hours is acceptable because of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 24 hour period. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the incore power distribution measurement, perform the required calculations, and evaluate $F^N_{\Delta H}$.

(continued)

BASES

ACTIONS (continued)

A.3

Verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence ensures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F^N_{\Delta H}$ limit is within the LCO limits prior to exceeding 50% RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is ≥ 95% RTP.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced prior to performing this Action.

B.1

When Required Actions A.1.1 through A.3 cannot be completed within their required Completion Times, the plant must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience regarding the time required to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The value of $F^N_{\Delta H}$ is determined by using the PDMS to obtain an incore power distribution measurement. A data reduction computer program then calculates the maximum value of $F^N_{\Delta H}$ from the measured flux distributions. The measured value of $F^N_{\Delta H}$ must be multiplied by a factor to account for measurement uncertainty before making comparisons to the $F^N_{\Delta H}$ limit.

When the PDMS is used to obtain the incore power distribution measurement, the factor $(1+U_{\Delta H}/100)$ is calculated and applied automatically by the BEACON™ software (References 4 and 5).

After the initial fuel loading and each refueling, $F^N_{\Delta H}$ must be determined in MODE 1 prior to exceeding 75% RTP. This requirement ensures that $F^N_{\Delta H}$ limits are met at the beginning of each fuel cycle.

The 31 EFPD Frequency is acceptable because the power distribution changes relatively slowly over this amount of fuel burnup. Accordingly, this Frequency is short enough that the $F^N_{\Delta H}$ limit cannot be exceeded for any significant period of operation.

BASES (continued)

REFERENCES

1. Regulatory Guide 1.77, Rev. 0, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors," May 1974.

2. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants," GDC 26, "Reactivity Control System Redundancy and Capability."

3. Title 10, Code of Federal Regulations, Part 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors."

4. WCAP-12472-P-A, “BEACON™ Core Monitoring and Operations Support System,” August 1994.

5. WCAP-12472-P-A, “BEACON™ Core Monitoring and Operations Support System,” Addendum 2, April 2002.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL FLUX DIFFERENCE (AFD)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the amount of axial power distribution skewing to either the top or bottom of the core. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in axial power distribution control.

Relaxed Axial Offset Control (RAOC) methodology is a calculational procedure that defines the allowed operational space of the AFD versus THERMAL POWER. The AFD limits are selected by considering a range of axial xenon distributions that may occur as a result of large variations of the AFD. Subsequently, power peaking factors and power distributions are examined to ensure that the loss of coolant accident (LOCA), loss of flow accident, and anticipated transient limits are met. Violation of the AFD limits invalidate the conclusions of the accident and transient analyses with regard to fuel cladding integrity.

Although the RAOC defines limits that must be met to satisfy safety analyses, typically an operating scheme, Constant Axial Offset Control (CAOC), is used to control axial power distribution in day to day operation (Ref. 1). CAOC requires that the AFD be controlled within a narrow tolerance band around a burnup dependent target to minimize the variation of axial peaking factors and axial xenon distribution during unit maneuvers.

The CAOC operating space is typically smaller and lies within the RAOC operating space. Control within the CAOC operating space constrains the variation of axial xenon distributions and axial power distributions. RAOC calculations assume a wide range of xenon distributions and then confirm that the resulting power distributions satisfy the requirements of the accident analyses.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The AFD is a measure of the axial power distribution skewing to either the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution, and, to a lesser extent, reactor coolant temperature and boron concentration.

The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

The RAOC methodology (Ref. 2) establishes a xenon distribution library with tentatively wide AFD limits. One dimensional axial power distribution calculations are then performed to demonstrate that normal operation power shapes are acceptable for the LOCA and loss of flow accident, and for initial conditions of anticipated transients. The tentative limits are adjusted as necessary to meet the safety analysis requirements.

The limits on the AFD ensure that the Heat Flux Hot Channel Factor ($F_Q(Z)$) is not exceeded during either normal operation or in the event of xenon redistribution following power changes. The limits on the AFD also restrict the range of power distributions that are used as initial conditions in the analyses of Condition 2, 3, or 4 events. This ensures that the fuel cladding integrity is maintained for these postulated accidents. The most important Condition 4 event is the LOCA. The most important Condition 3 event is the loss of flow accident. The most important Condition 2 events are uncontrolled bank withdrawal and boration or dilution accidents. Condition 2 accidents simulated to begin from within the AFD limits are used to confirm the adequacy of the Overpower ΔT and Overtemperature ΔT trip setpoints.

The limits on the AFD satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator through the manual operation of the control banks or automatic motion of control banks. The automatic motion of the control banks is in response to temperature deviations resulting from manual operation of the Chemical and Volume Control System to change boron concentration or from power level changes.

Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors (Ref. 3). Separate signals are taken from the top and bottom detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom excore detectors in each detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as %Δ flux.

The AFD limits are provided in the COLR. Figure B 3.2.3-1 shows typical RAOC AFD limits. The AFD limits for RAOC do not depend on the target flux difference. However, the target flux difference may be used to minimize changes in the axial power distribution.

Violating this LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its specified limits.

APPLICABILITY

The AFD requirements are applicable in MODE 1 greater than or equal to 50% RTP when the combination of THERMAL POWER and core peaking factors are of primary importance in safety analysis.

For AFD limits developed using RAOC methodology, the value of the AFD does not affect the limiting accident consequences with THERMAL POWER < 50% RTP and for lower operating power MODES.

ACTIONS

A.1

As an alternative to restoring the AFD to within its specified limits, Required Action A.1 requires a THERMAL POWER reduction to < 50% RTP. This places the core in a condition for which the value of the AFD is not important in the applicable safety analyses. A Completion Time of 30 minutes is reasonable, based on operating experience, to reach 50% RTP without challenging plant systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

The AFD is monitored on an automatic basis using the unit process computer, which has an AFD monitor alarm. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm message immediately if the AFD for two or more OPERABLE excore channels is outside its specified limits.

This Surveillance verifies that the AFD, as indicated by the NIS excore channel, is within its specified limits and is consistent with the status of the AFD monitor alarm. With the AFD monitor alarm inoperable, the AFD is monitored every hour to detect operation outside its limit. The Frequency of 1 hour is based on operating experience regarding the amount of time required to vary the AFD, and the fact that the AFD is closely monitored. With the AFD monitor alarm OPERABLE, the Surveillance Frequency of 7 days is adequate considering that the AFD is monitored by a computer and any deviation from requirements is alarmed.

REFERENCES

1. WCAP-8385 (Proprietary), "Power Distribution Control and Load Following Procedures," Westinghouse Electric Corporation, September 1974.

2. R. W. Miller et al., "Relaxation of Constant Axial Offset Control: F_Q Surveillance Technical Specification," WCAP-10216-P-A, June 1983.

3. Watts Bar FSAR, Section 7.7, "Control Systems."

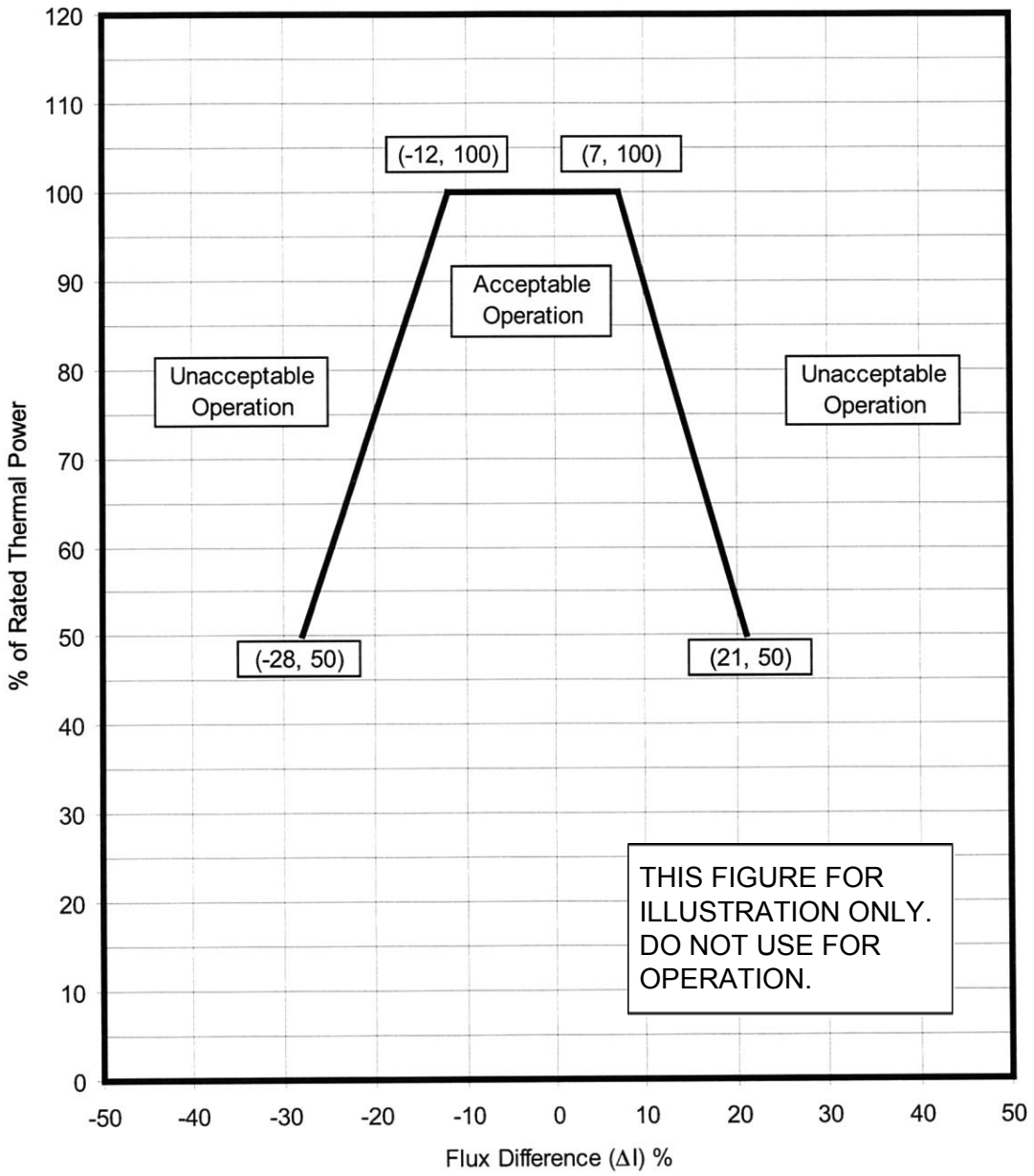


Figure B 3.2.3-1

TYPICAL AXIAL FLUX DIFFERENCE

Acceptable Operation Limits as a Function of RATED THERMAL POWER

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, and LCO 3.1.7, "Control Rod Insertion Limits," provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident, the peak cladding temperature must not exceed 2200°F (Ref. 1);

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition;

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 280 cal/gm (Ref. 2); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), rod group alignment, sequence, overlap, and control bank insertion are established to preclude core power distributions that exceed the safety analyses limits.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The QPTR limits ensure that $F^N_{\Delta H}$ and $F_Q(Z)$ remain below their limiting values by preventing an undetected change in the gross radial power distribution.

In MODE 1, the $F^N_{\Delta H}$ and $F_Q(Z)$ limits must be maintained to preclude core power distributions from exceeding design limits assumed in the safety analyses.

The QPTR satisfies Criterion 2 of 10 CFR50.36(c)(2)(ii).

LCO

The QPTR limit of 1.02, at which corrective action is required, provides a margin of protection for both the DNB ratio and linear heat generation rate contributing to excessive power peaks resulting from X-Y plane power tilts. A limiting QPTR of 1.02 can be tolerated before the margin for uncertainty in $F_Q(Z)$ and ($F^N_{\Delta H}$) is possibly challenged.

APPLICABILITY

The QPTR limit must be maintained in MODE 1 with THERMAL POWER > 50% RTP to prevent core power distributions from exceeding the design limits.

Applicability in MODE 1 ≤ 50% RTP and in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require the implementation of a QPTR limit on the distribution of core power. The QPTR limit in these conditions is, therefore, not important. Note that the $F^N_{\Delta H}$ and $F_Q(Z)$ LCOs still apply, but allow progressively higher peaking factors at 50% RTP or lower.

ACTIONS

A.1

With the QPTR exceeding its limit, a power level reduction of 3% RTP for each 1% by which the QPTR exceeds 1.00 is a conservative tradeoff of total core power with peak linear power. The Completion Time of 2 hours allows sufficient time to identify the cause and correct the tilt. Note that the power reduction itself may cause a change in the tilted condition.

(continued)

BASES

ACTIONS (continued)

A.2

After completion of Required Action A.1, the QPTR Alarm may still be in its alarmed state. As such, any additional changes in the QPTR are detected by requiring a check of the QPTR once per 12 hours thereafter. If the QPTR continues to increase, THERMAL POWER has to be reduced accordingly. A 12-hour Completion Time is sufficient because any additional change in QPTR would be relatively slow.

A.3

The peaking factors $F_{\Delta H}^{N}$ and $F_Q(Z)$ are of primary importance in ensuring that the power distribution remains consistent with the initial conditions used in the safety analyses. Performing SRs on $F_{\Delta H}^{N}$ and $F_Q(Z)$ within the Completion Time of 24 hours ensures that these primary indicators of power distribution are within their respective limits. A Completion Time of 24 hours takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and perform an incore power distribution measurement. If these peaking factors are not within their limits, the Required Actions of these Surveillances provide an appropriate response for the abnormal condition. If the QPTR remains above its specified limit, the peaking factor surveillances are required each 7 days thereafter to evaluate $F_{\Delta H}^{N}$ and $F_Q(Z)$ with changes in power distribution. Relatively small changes are expected due to either burnup and xenon redistribution or correction of the cause for exceeding the QPTR limit.

A.4

Although $F_{\Delta H}^{N}$ and $F_Q(Z)$ are of primary importance as initial conditions in the safety analyses, other changes in the power distribution may occur as the QPTR limit is exceeded and may have an impact on the validity of the safety analysis. A change in the power distribution can affect such reactor parameters as bank worths and peaking factors for rod malfunction accidents. When the QPTR exceeds its limit, it does not necessarily mean a safety concern exists. It does mean that there is an indication of a change in the gross radial power distribution that requires an investigation and evaluation that is accomplished by examining the incore power distribution. Specifically, the core peaking factors and the quadrant tilt must be evaluated because they are the factors that best characterize the core power distribution. This re-evaluation is required to ensure that, before increasing THERMAL POWER to above the limit of Required Action A.1, the reactor core conditions are consistent with the assumptions in the safety analyses.

(continued)

ACTIONS (continued)

A.5

If the QPTR has exceeded the 1.02 limit and a re-evaluation of the safety analysis is completed and shows that safety requirements are met, the excore detectors are recalibrated to show a QPTR of 1.0 prior to increasing THERMAL POWER to above the limit of Required Action A.1. This is done to detect any subsequent significant changes in QPTR.

Required Action A.5 is modified by a Note that states that the QPTR is not zeroed out until after the re-evaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). This Note is intended to prevent any ambiguity about the required sequence of actions.

A.6

Once the flux tilt is zeroed out (i.e., Required Action A.5 is performed), it is acceptable to return to full power operation. However, as an added check that the core power distribution at RTP is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(Z)$ and $F^N_{\Delta H}$ are within their specified limits within 24 hours of reaching RTP. As an added precaution, if the core power does not reach RTP within 24 hours, but is increased slowly, then the peaking factor surveillances must be performed within 48 hours of the time when the ascent to power was begun. These Completion Times are intended to allow adequate time to increase THERMAL POWER to above the limit of Required Action A.1, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

Required Action A.6 is modified by a Note that states that the peaking factor surveillances may only be done after the excore detectors have been calibrated to show zero tilt (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are calibrated to show zero tilt and the core returned to power.

(continued)

BASES

ACTIONS (continued)

B.1

If Required Actions A.1 through A.6 are not completed within their associated Completion Times, the unit must be brought to a MODE or condition in which the requirements do not apply. To achieve this status, THERMAL POWER must be reduced to < 50% RTP within 4 hours. The allowed Completion Time of 4 hours is reasonable, based on operating experience regarding the amount of time required to reach the reduced power level without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

SR 3.2.4.1 is modified by two Notes. Note 1 allows QPTR to be calculated with three power range channels if THERMAL POWER is < 75% RTP and the input from one power range neutron flux channel is inoperable. Note 2 allows performance of SR 3.2.4.2 in lieu of SR 3.2.4.1 if more than one input from power range neutron flux channels are inoperable.

This Surveillance verifies that the QPTR, as indicated by the Nuclear Instrumentation System (NIS) excore channels, is within its limits. The Frequency of 7 days when the QPTR alarm is OPERABLE is acceptable because of the low probability that this alarm can remain inoperable without detection.

When the QPTR alarm is inoperable, the Frequency is increased to 12 hours. This Frequency is adequate to detect any relatively slow changes in QPTR, because for those changes of QPTR that occur quickly (e.g., a dropped rod), there typically are other indications of abnormality that prompt a verification of core power tilt.

SR 3.2.4.2

This Surveillance is modified by a Note, which states that it is required only when the input from one or more power range neutron flux channels are inoperable and the THERMAL POWER is ≥ 75% RTP.

With an NIS power range channel inoperable, tilt monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. Performing SR 3.2.4.2 at a Frequency of 12 hours provides an accurate alternative means for ensuring that any tilt remains within its limits.

(continued)

BASES (Continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.4.2 (continued)

For the purpose of monitoring the QPTR when the input from one or more power range neutron flux channels is inoperable, incore power distribution measurement information is used to confirm that the normalized symmetric power distribution is consistent with the indicated QPTR and the reference normalized symmetric power distribution. The incore power distribution measurement information can be used to generate an incore "tilt." This tilt can be compared to the reference incore tilt to generate an incore QPTR. Therefore, incore QPTR can be used to confirm that excore QPTR is within limits.

The incore power distribution measurement information can be obtained from an OPERABLE Power Distribution Monitoring System (PDMS) (Ref. 4).

The reference normalized symmetric power distribution is available from the last incore power distribution measurement information used to calibrate the excore axial offset. The reference incore power distribution measurement information is obtained from an OPERABLE PDMS.

With the input from one or more power range neutron flux channels inoperable, the indicated QPTR may be changed from the value indicated with all four channels OPERABLE. To confirm that no change in tilt has actually occurred, which might cause the QPTR limit to be exceeded, the normalized quadrant tilt is compared against the reference normalized quadrant tilt. Nominally, quadrant tilt from the surveillance should be within 2% of the tilt shown by the reference incore power distribution measurement information.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors."

2. Regulatory Guide 1.77, Rev. 0, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors," May 1974.

3. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants," GDC 26, "Reactivity Control System Redundancy and Capability."

4. WCAP-12472-P-A, "BEACON™ Core Monitoring and Operations Support System," August 1994 (Addendum 2, April 2002).

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Trip System (RTS) Instrumentation

BASES

BACKGROUND

The RTS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during Anticipated Operational Occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RTS, as well as specifying LCOs on other reactor system parameters and equipment performance.

Technical Specifications are required by 10 CFR 50.36 to include LSSS for variables that have significant safety functions. LSSS are defined by the regulation as “Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded.” The Analytical Limit is the limit of the process variable at which a protective action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur.

The Nominal Trip Setpoint (NTSP) specified in Table 3.3.1-1 is a predetermined setting for a protection channel chosen to ensure automatic actuation prior to the process variable reaching the Analytical Limit and thus ensuring that the SL would not be exceeded. As such, the NTSP accounts for uncertainties in setting the channel (e.g., calibration), uncertainties in how the channel might actually perform (e.g., repeatability), changes in the point of action of the channel over time (e.g., drift during surveillance intervals), and any other factors which may influence its actual performance (e.g., harsh accident environments). In this manner, the NTSP ensures that SLs are not exceeded. Therefore, the NTSP meets the definition of an LSSS (Ref. 6).

(continued)

BASES

BACKGROUND (continued)

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in the Technical Specifications as "… being capable of performing its safety function(s)." Relying solely on the NTSP to define OPERABILITY in Technical Specifications would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as found" value of a protection channel setting during a surveillance. This would result in Technical Specification compliance problems, as well as reports and corrective actions required by the rule which are not necessary to ensure safety. For example, an automatic protection channel with a setting that has been found to be different from the NTSP due to some drift of the setting may still be OPERABLE since drift is to be expected. This expected drift would have been specifically accounted for in the setpoint methodology for calculating the NTSP and thus the automatic protective action would still have ensured that the SL would not be exceeded with the "as found" setting of the protection channel. Therefore, the channel would still be OPERABLE since it would have performed its safety function and the only corrective action required would be to reset the channel within the established as left tolerance around the NTSP to account for further drift during the next surveillance interval.

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits are:

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling (DNB);

2. Fuel centerline melt shall not occur; and

3. The RCS pressure SL of 2735 psig (2750 psia) shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 20 and 10 CFR 100 criteria during AOOs.

Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit during accidents is that offsite dose shall be maintained within an acceptable fraction of 10 CFR 100 limits. Different accident categories are allowed a different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

(continued)

BASES

BACKGROUND (continued)

The RTS instrumentation is segmented into four distinct but interconnected modules as illustrated in Figure 7.1-1, FSAR, Section 7 (Ref. 2), and as identified below:

1. Field transmitters or process sensors: provide a measurable electronic signal or contact actuation based upon the physical characteristics of the parameter being measured;

2. Signal Process Control and Protection System, including Process Protection System, Nuclear Instrumentation System (NIS), and field contacts: provides analog to digital conversion (Digital Protection System), signal conditioning, setpoint comparison, process algorithm actuation (Digital Protection System), compatible electrical signal output to protection system channels, and control board/control room/miscellaneous indications;

3. Solid State Protection System (SSPS), including input, logic, and output bays: initiates proper unit shutdown and/or ESF actuation in accordance with the defined logic, which is based on the bistable, setpoint comparators, or contact outputs from the signal process control and protection system; and

4. Reactor trip switchgear, including reactor trip breakers (RTBs) and bypass breakers: provides the means to interrupt power to the control rod drive mechanisms (CRDMs) and allows the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as five, field transmitters or sensors are used to measure unit parameters. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the NTSP and Allowable Value. The OPERABILITY of each transmitter or sensor is determined by either "as found" calibration data evaluated during the CHANNEL CALIBRATION or by qualitative assessment of field transmitter or sensor as related to the channel behavior observed during performance of the CHANNEL CHECK.

(continued)

BASES

BACKGROUND (continued)

Signal Process Control and Protection System

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with NTSPs derived from Analytical Limits established by the safety analyses. Analytical Limits are defined in FSAR, Chapter 6 (Ref. 1), Chapter 7 (Ref. 2), and Chapter 15 (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable, setpoint comparator, or contact is forwarded to the SSPS for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the SSPS and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation. These requirements are described in IEEE-279-1971 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2.

Two logic trains are required to ensure no single random failure of a logic train will disable the RTS. The logic trains are designed such that testing required while the reactor is at power may be accomplished without causing trip.

(continued)

BASES

BACKGROUND (continued)

Allowable Values and Nominal Trip Setpoints

The Trip Setpoints used in the bistables, setpoint comparators, or contact trip outputs are based on the analytical limits defined in Reference 2. The calculation of the Nominal Trip Setpoints specified in Table 3.3.1-1 is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those RTS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservative with respect to the analytical limits.

A detailed description of the methodology used to calculate the Allowable Values, NTSPs, and as left and as found tolerance bands is provided in Reference 2. All of the known uncertainties applicable for each channel are factored into the determination of each NTSP and corresponding Allowable Value. The trip setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for measurement errors detectable by the COT. The Allowable Value serves as the as found Technical Specification OPERABILITY limit for the purpose of the COT.

The NTSP is the value at which the bistable is set and is the expected value to be achieved during calibration. The NTSP value is the LSSS and ensures the safety analysis limits are met for the surveillance interval selected when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the “as left” NTSP value is within the as left tolerance band for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration and comparator setting uncertainties). The NTSP value is therefore considered a “nominal” value (i.e., expressed as a value without inequalities) for the purposes of COT and CHANNEL CALIBRATION.

Nominal Trip Setpoints, in conjunction with the use of as found and as left tolerances, together with the requirements of the Allowable Value ensure that SLs are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions are designed).

Note that the Allowable Values listed in Table 3.3.1-1 are the least conservative value of the as found setpoint that a channel can have during a periodic CHANNEL CALIBRATION, CHANNEL OPERATIONAL TESTS, or a TRIP ACTUATING DEVICE OPERATIONAL TEST that requires trip setpoint verification.

(continued)

BASES

BACKGROUND

Allowable Values and Nominal Trip Setpoints (continued)

Each channel of the process control equipment can be tested on line to verify that the signal or setpoint accuracy is within the allowance requirements of Reference 2. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section. The Process Protection System is designed to permit any one channel to be tested and maintained at power in a bypassed mode. If a channel has been bypassed for any purpose, the bypass is continuously indicated in the control room.

Solid State Protection System

The SSPS equipment is used for the decision logic processing of setpoint comparator trip outputs, contact outputs, and bistable outputs from the signal processing equipment. To meet the redundancy requirements, two trains of SSPS, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide reactor trip and/or ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to trip in the event of a loss of power, directing the unit to a safe shutdown condition.

The SSPS performs the decision logic for actuating a reactor trip or ESF actuation, generates the electrical output signal that will initiate the required trip or actuation, and provides the status, permissive, and annunciator output signals to the main control room of the unit.

The setpoint comparator trip outputs, contact outputs and bistable outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic matrices that represent combinations indicative of various unit upset and accident transients. If a required logic matrix combination is completed, the system will initiate a reactor trip and/or send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

(continued)

BASES

BACKGROUND (continued)

Reactor Trip Switchgear

The RTBs are in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening of the RTBs interrupts power to the CRDMs, which allows the shutdown rods and control rods to fall into the core by gravity. Each RTB is equipped with a bypass breaker to allow testing of the RTB while the unit is at power. During normal operation the output from the SSPS is a voltage signal that energizes the undervoltage coils in the RTBs and bypass breakers, if in use. When the required logic matrix combination is completed, the SSPS output voltage signal is removed, the undervoltage coils are de-energized, the breaker trip lever is actuated by the de-energized undervoltage coil, and the RTBs and bypass breakers are tripped open. This allows the shutdown rods and control rods to fall into the core. In addition to the de-energization of the undervoltage coils, each breaker is also equipped with a shunt trip device that is energized to trip the breaker open upon receipt of a reactor trip signal from the SSPS. Either the undervoltage coil or the shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism.

The decision logic matrix Functions are described in the functional diagrams included in Reference 2. In addition to the reactor trip or ESF, these diagrams also describe the various "permissive interlocks" that are associated with unit conditions. Each train has a built in testing device that can automatically test the decision logic matrix Functions and the actuation channels while the unit is at power.

When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed. The testing device is semiautomatic to minimize testing time.

BASES (continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RTS functions to preserve the SLs during all AOOs and mitigates the consequences of DBAs in all MODES in which the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted.

Each of the analyzed accidents and transients can be detected by one or more RTS Functions. The accident analysis described in Reference 3 takes credit for most RTS trip functions. RTS trip functions that are retained yet not specifically credited in the accident analysis are implicitly credited in the safety analysis and the NRC staff approved licensing basis for the unit. These RTS trip Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. They may also serve as backups to RTS trip Functions that were credited in the accident analysis.

Permissive and interlock setpoints allow the blocking of trips during plant startups, and restoration of trips when the permissive conditions are not satisfied, but they are not explicitly modeled in the Safety Analyses. These permissives and interlocks ensure that the starting conditions are consistent with the safety analysis, before preventive or mitigating actions occur. Because these permissives or interlocks are only one of multiple conservative starting assumptions for the accident analysis, they are generally considered as nominal values without regard to measurement accuracy.

The LCO requires all instrumentation performing an RTS Function, listed in Table 3.3.1-1 to be OPERABLE. The Allowable Value specified in Table 3.3.1-1 is the least conservative value of the as found setpoint that the channel can have when tested, such that a channel is OPERABLE if the as found setpoint is within the as found tolerance and is conservative with the respect to the Allowable Value during a CHANNEL CALIBRATION or CHANNEL OPERATIONAL TEST (COT). As such, the Allowable Value differs from the NTSP by an amount greater than or equal to the expected instrument channel uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the channel (NTSP) will ensure that a SL is not exceeded at any given point of time as long as the channel has not drifted beyond expected tolerances during the surveillance interval. Note that, although the channel is OPERABLE under these circumstances, the trip setpoint must be left adjusted to a value within the as left tolerance, in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned (as found criteria).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

If the actual setting of the channel is found to be conservative with respect to the Allowable Value but is beyond the as found tolerance band, the channel is OPERABLE but degraded. The degraded condition of the channel will be further evaluated during performance of the SR. This evaluation will consist of resetting the channel setpoint to the NTSP (within the allowed tolerance), and evaluating the channel response. If the channel is functioning as required and is expected to pass the next surveillance, then the channel is OPERABLE and can be restored to service at the completion of the surveillance. After the surveillance is completed, the channel as found condition will be entered into the Corrective Action Program for further evaluation.

A trip setpoint may be set more conservative than the NTSP as necessary in response to plant conditions. However, in this case, the operability of this instrument must be verified based on the field setting and not the NTSP. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation Function, two channels of Manual Reactor Trip in each logic Function, and two trains in each Automatic Trip Logic Function. Four OPERABLE instrumentation channels in a two-out-of-four configuration are required when one RTS channel is also used as a control system input. This configuration accounts for the possibility of the shared channel failing in such a manner that it creates a transient that requires RTS action. In this case, the RTS will still provide protection, even with random failure of one of the other three protection channels. Three operable instrumentation channels in a two-out-of-three configuration are generally required when there is no potential for control system and protection system interaction that could simultaneously create a need for RTS trip and disable one RTS channel. The two-out-of-three and two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing a reactor trip. Specific exceptions to the above general philosophy exist and are discussed below.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Reactor Trip System Functions

The safety analyses and OPERABILITY requirements applicable to each RTS Function are discussed below:

1. Manual Reactor Trip

The Manual Reactor Trip ensures that the control room operator can initiate a reactor trip at any time by using either of two reactor trip switches in the control room. A Manual Reactor Trip accomplishes the same results as any one of the automatic trip Functions. It is used by the reactor operator to shut down the reactor whenever any parameter is rapidly trending toward its Trip Setpoint.

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip switch. Each channel actuates the reactor trip breakers in both trains. Two independent channels are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Function.

In MODE 1 or 2, manual initiation of a reactor trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the manual initiation Function must also be OPERABLE if the shutdown rods or control rods are withdrawn or the Control Rod Drive (CRD) System is capable of withdrawing the shutdown rods or the control rods. In this condition, inadvertent control rod withdrawal is possible. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the CRD System is not capable of withdrawing the shutdown rods or control rods. If the rods cannot be withdrawn from the core, there is no need to be able to trip the reactor because all of the rods are inserted. In MODE 6, neither the shutdown rods nor the control rods are permitted to be withdrawn and the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function is not required.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. Power Range Neutron

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS power range detectors provide input to the Rod Control System and the Steam Generator (SG) Water Level Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

a. Power Range Neutron Flux - High

The Power Range Neutron Flux - High trip Function ensures that protection is provided, from all power levels, against a positive reactivity excursion leading to DNB during power operations.

These can be caused by rod withdrawal or reductions in RCS temperature.

The LCO requires all four of the Power Range Neutron Flux - High channels to be OPERABLE.

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux - High trip must be OPERABLE. This Function will terminate the reactivity excursion and shut down the reactor prior to reaching a power level that could damage the fuel. In MODE 3, 4, 5, or 6, the NIS power range detectors cannot detect neutron levels in this range. In these MODES, the Power Range Neutron Flux - High does not have to be OPERABLE because the reactor is shut down and reactivity excursions into the power range are extremely unlikely. Other RTS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Power Range Neutron Flux - Low

The LCO requirement for the Power Range Neutron Flux - Low trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions.

The LCO requires all four of the Power Range Neutron Flux - Low channels to be OPERABLE.

In MODE 1, below the Power Range Neutron Flux (P-10 setpoint), and in MODE 2, the Power Range Neutron Flux - Low trip must be OPERABLE. This Function may be manually blocked by the operator when two out of four power range channels are greater than approximately 10% RTP (P-10 setpoint). This Function is automatically unblocked when three out of four power range channels are below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the Power Range Neutron Flux - High trip Function.

In MODE 3, 4, 5, or 6, the Power Range Neutron Flux - Low trip Function does not have to be OPERABLE because the reactor is shut down and the NIS power range detectors cannot detect neutron levels in this range. Other RTS trip Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

3. Power Range Neutron Flux Rate

The Power Range Neutron Flux Rate trip uses the same channels as discussed for Function 2 above.

a. Power Range Neutron Flux - High Positive Rate

The Power Range Neutron Flux - High Positive Rate trip Function ensures that protection is provided against rapid increases in neutron flux that are characteristic of an RCCA drive rod housing rupture and the accompanying ejection of the RCCA. This Function complements the Power Range Neutron Flux - High and - Low Setpoint trip Functions to ensure that the criteria are met for a rod ejection from the power range.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Power Range Neutron Flux - High Positive Rate (continued)

The LCO requires all four of the Power Range Neutron Flux - High Positive Rate channels to be OPERABLE.

In MODE 1 or 2, when there is a potential to add a large amount of positive reactivity from a rod ejection accident (REA), the Power Range Neutron Flux - High Positive Rate trip must be OPERABLE. In MODE 3, 4, 5, or 6, the Power Range Neutron Flux - High Positive Rate trip Function does not have to be OPERABLE because other RTS trip Functions and administrative controls will provide protection against positive reactivity additions. Also, since only the shutdown banks may be withdrawn in MODE 3, 4, or 5, the remaining complement of control bank worth ensures a sufficient degree of SDM in the event of an REA. In MODE 6, no rods are withdrawn and the SDM is increased during refueling operations. The reactor vessel head is also removed or the closure bolts are detensioned preventing any pressure buildup. In addition, the NIS power range detectors cannot detect neutron levels present in this MODE.

b. Power Range Neutron Flux - High Negative Rate

Deleted

4. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides backup protection to the Power Range Neutron Flux - Low Setpoint trip Function. The NIS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS intermediate range detectors do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip.

The LCO requires two channels of Intermediate Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4. Intermediate Range Neutron Flux (continued)

Because this trip Function is important only during startup, there is generally no need to disable channels for testing while the Function is required to be OPERABLE. Therefore, a third channel is unnecessary.

In MODE 1 below the P-10 setpoint, and in MODE 2, when there is a potential for an uncontrolled RCCA bank rod withdrawal accident during reactor startup, the Intermediate Range Neutron Flux trip must be OPERABLE. Above the P-10 setpoint, the Power Range Neutron Flux - High Setpoint trip provides core protection for a rod withdrawal accident. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because the control rods must be fully inserted and only the shutdown rods may be withdrawn. The reactor cannot be started up in this condition. The core also has the required SDM to mitigate the consequences of a positive reactivity addition accident. In MODE 6, all rods are fully inserted and the core has a required increased SDM.

5. Source Range Neutron Flux

The LCO requirement for the Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA rod bank withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux - Low Setpoint and Intermediate Range Neutron Flux trip Functions. In MODES 3, 4, and 5, administrative controls also prevent the uncontrolled withdrawal of rods. The NIS source range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RTS automatic protection function required in MODES 3, 4, and 5. Therefore, the functional capability at the specified Trip Setpoint is assumed to be available.

The LCO requires two channels of Source Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function. The LCO also requires one channel of the Source Range Neutron Flux to be OPERABLE in MODE 3, 4, or 5 with RTBs open.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. Source Range Neutron Flux (continued)

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical, boron dilution and control rod ejection events. The Function also provides visual neutron flux indication in the control room.

In MODE 2 when below the P-6 setpoint during a reactor startup, the Source Range Neutron Flux trip must be OPERABLE. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux - Low Setpoint trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the NIS Source Range Neutron Flux trip Function is disabled and inoperable.

In MODE 3, 4, or 5 with the reactor shut down, the Source Range Neutron Flux trip Function must also be OPERABLE. If the CRD System is capable of rod withdrawal, the Source Range Neutron Flux trip must be OPERABLE to provide core protection against a rod withdrawal accident. If the CRD System is not capable of rod withdrawal, the source range detectors are not required to trip the reactor. However, their monitoring Function must be OPERABLE to monitor core neutron levels and provide visual indication and audible alarm of reactivity changes that may occur as a result of events like a boron dilution. The requirements for the NIS source range detectors in MODE 6 are addressed in LCO 3.9.3, "Nuclear Instrumentation."

6. Overtemperature ΔT

The Overtemperature ΔT trip Function is provided to ensure that the design limit DNBR is met. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include pressurizer pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system. The Function monitors both variation in power and flow since a decrease in flow has the same effect on ΔT as a power increase. The Overtemperature ΔT trip

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Overtemperature ΔT (continued)

Function uses each loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature - the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;

- pressurizer pressure - the Trip Setpoint is varied to correct for changes in system pressure; and

- axial power distribution - the f(ΔI) Overtemperature ΔT Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the design limit, as indicated by the difference between the upper and lower NIS power range detectors, the Trip Setpoint is reduced in accordance with Note 1 of Table 3.3.1-1.

Dynamic compensation is included for delays associated with fluid transport from the core to the loop temperature detectors (RTDs), and thermowell and RTD response time delays.

ΔT_0, as used in the Overtemperature and Overpower ΔT trips, represents the 100% RTP value as measured for each loop. T' represents the 100% RTP T_{avg} value as measured by the plant for each loop. ΔT_0 and T' normalize each loop's ΔT setpoint to the actual operating conditions existing at the time of measurement, thus forcing the setpoint to reflect the equivalent full power conditions as assumed in the accident analyses. Differences in RCS loop ΔT and T_{avg} can be due to several factors, e.g., measured RCS loop flow greater than minimum measured flow, and slightly asymmetric power distributions between quadrants. While RCS loop flows are not expected to change with cycle life, radial power redistribution between quadrants may occur, resulting in small changes in loop specific ΔT and T_{avg} values. Loop specific values of ΔT_0 and T' must be determined at the beginning of each fuel cycle at full power, steady-state conditions (i.e., power distribution not affected by xenon transient conditions) and will be checked quarterly and updated, if required. Tolerances for ΔT_0 and T' have been included in the determination of the Overtemperature ΔT setpoint.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Overtemperature ΔT (continued)

The Overtemperature ΔT trip Function is calculated for each loop as described in Note 1 of Table 3.3.1-1. Trip occurs if Overtemperature ΔT is indicated in two loops. The pressure and temperature signals are used for other control functions. The actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to generate turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a reactor trip.

The LCO requires all four channels of the Overtemperature ΔT trip Function to be OPERABLE. Note that the Overtemperature ΔT Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

7. Overpower ΔT

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also limits the required range of the Overtemperature ΔT trip Function and provides a backup to the Power Range Neutron Flux - High Setpoint trip.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Overpower ΔT (continued)

The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature - the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature; and

- rate of change of reactor coolant average temperature - including dynamic compensation for delays associated with fluid transport from the core to the loop temperature detectors (RTDs),and thermowell and RTD response time delays.

ΔT_0, as used in the Overtemperature and Overpower ΔT trips, represents the 100% RTP value as measured for each loop. T" represents the 100% RTP T_{avg} value as measured by the plant for each loop. ΔT_0 and T" normalize each loop's ΔT setpoint to the actual operating conditions existing at the time of measurement, thus forcing the setpoint to reflect the equivalent full power conditions as assumed in the accident analyses. Differences in RCS loop ΔT and T_{avg} can be due to several factors, e.g., measured RCS loop flow greater than minimum measured flow, and slightly asymmetric power distributions between quadrants. While RCS loop flows are not expected to change with cycle life, radial power redistribution between quadrants may occur, resulting in small changes in loop specific ΔT and T_{avg} values. Loop specific values of ΔT_0 and T" must be determined at the beginning of each fuel cycle at full power, steady-state conditions (i.e., power distribution not affected by xenon transient conditions) and will be checked quarterly and updated, if required. Tolerances for ΔT_0 and T" have been included in the determination of the Overtemperature ΔT setpoint.

The Overpower ΔT trip Function is calculated for each loop as per Note 2 of Table 3.3.1-1. Trip occurs if Overpower ΔT is indicated in two loops. The temperature signals are used for other control functions. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation and a single failure in the remaining channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Overpower ΔT (continued)

to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overpower ΔT condition and may prevent a reactor trip.

The LCO requires four channels of the Overpower ΔT trip Function to be OPERABLE. Note that the Overpower ΔT trip Function receives input from channels shared with other RTS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overpower ΔT trip Function must be OPERABLE. These are the only times that enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel.

In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

8. Pressurizer Pressure

The same sensors provide input to the Pressurizer Pressure - High and - Low trips and the Overtemperature ΔT trip. The Pressurizer Pressure channels are also used to provide input to the Pressurizer Pressure Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation.

a. Pressurizer Pressure - Low

The Pressurizer Pressure - Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure.

The LCO requires all four channels of Pressurizer Pressure - Low to be OPERABLE in MODE 1 above P-7.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Pressurizer Pressure - Low (continued)

In MODE 1, when DNB is a major concern, the Pressurizer Pressure - Low trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock (NIS power range P-10 or turbine impulse pressure greater than approximately 10% of full power equivalent (P-13)). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, no conceivable power distributions can occur that would cause DNB concerns.

b. Pressurizer Pressure - High

The Pressurizer Pressure - High trip Function ensures that protection is provided against overpressurizing the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions.

The LCO requires all four channels of the Pressurizer Pressure - High to be OPERABLE.

The Pressurizer Pressure - High LSSS is selected to be below the pressurizer safety valve actuation pressure and above the power operated relief valve (PORV) setting. This setting minimizes challenges to safety valves while avoiding unnecessary reactor trip for those pressure increases that can be controlled by the PORVs.

In MODE 1 or 2, the Pressurizer Pressure - High trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the relief and safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure - High trip Function does not have to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. Additionally, low temperature overpressure protection systems provide overpressure protection when below MODE 4.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

9. Pressurizer Water Level - High

The Pressurizer Water Level - High trip Function provides a backup signal for the Pressurizer Pressure - High trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. The LCO requires three channels of Pressurizer Water Level - High to be OPERABLE. The pressurizer level channels are used as input to the Pressurizer Level Control System. A fourth channel is not required to address control/protection interaction concerns. The level channels do not actuate the safety valves, and the high pressure reactor trip is set below the safety valve setting. Therefore, with the slow rate of charging available, pressure overshoot due to level channel failure cannot cause the safety valve to lift before reactor high pressure trip.

In MODE 1, when there is a potential for overfilling the pressurizer, the Pressurizer Water Level - High trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock. On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions.

10. Reactor Coolant Flow - Low

The Reactor Coolant Flow - Low trip Function ensures that protection is provided against violating the DNBR limit due to low flow in one or more RCS loops, while avoiding reactor trips due to normal variations in loop flow. Above the P-7 setpoint, the reactor trip on low flow in two or more RCS loops is automatically enabled. Above the P-8 setpoint, which is approximately 48% RTP, a loss of flow in any RCS loop will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow - Low channels per loop to be OPERABLE in MODE 1 above P-7.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

10. Reactor Coolant Flow - Low (continued)

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core because of the higher power level. In MODE 1 below the P-8 setpoint and above the P-7 setpoint, a loss of flow in two or more loops is required to actuate a reactor trip because of the lower power level and the greater margin to the design limit DNBR. Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since there is insufficient heat production to generate DNB conditions.

The Reactor Coolant Flow-Low Trip Setpoint and Allowable Value are specified in % indicated loop flow; however, the Eagle-21™ values entered through the MMI are specified in an equivalent % differential pressure.

11. Undervoltage Reactor Coolant Pumps

The Undervoltage RCPs trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The voltage to each RCP is monitored. Above the P-7 setpoint, a loss of voltage detected on two or more RCP buses will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow - Low Trip Setpoint is reached in two or more RCS loops. The loss of voltage in two loops must be sustained for a length of time equal to or greater than that set in the time delay. Time delays are incorporated into the Undervoltage RCPs channels to prevent reactor trips due to momentary electrical power transients.

The “Allowable Value” of greater than or equal to 5112 V includes the 3.5 cycle relay response time. This is required to ensure a reactor trip occurs before reaching a safety limit.

The undervoltage relay “Nominal Trip Setpoint” value of 5400 V includes the 3.5 cycle relay response time. This is required to meet the reactor trip nominal setpoint of 4830 V (Ref. 17).

The LCO requires one Undervoltage RCP channel per bus to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

11. Undervoltage Reactor Coolant Pumps (continued)

In MODE 1 above the P-7 setpoint, the Undervoltage RCP trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled.

12. Underfrequency Reactor Coolant Pumps

The Underfrequency RCPs trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops from a major network frequency disturbance. An underfrequency condition will slow down the pumps, thereby reducing their coastdown time following a pump trip. The proper coastdown time is required so that reactor heat can be removed immediately after reactor trip. The frequency of each RCP bus is monitored. Above the P-7 setpoint, a loss of frequency detected on two or more RCP buses will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow - Low Trip Setpoint is reached in two or more RCS loops. Time delays are incorporated into the Underfrequency RCPs channels to prevent reactor trips due to momentary electrical power transients.

The LCO requires one Underfrequency RCP channel per bus to be OPERABLE.

In MODE 1 above the P-7 setpoint, the Underfrequency RCPs trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled.

13. Steam Generator Water Level – Low-Low

Loss of the steam generator as a heat sink can be caused by the loss of normal feedwater, a station blackout or a feedline rupture. Feedline ruptures inside containment are protected by the containment high pressure trip Function (Ref. 3). Feedline ruptures outside containment and the other causes of the heat sink loss are protected by the SG Water Level - Low-Low trip Function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

13. Steam Generator Water Level – Low-Low (continued)

The SG Water Level – Low-Low trip Function ensures that protection is provided against a loss of heat sink and actuates the AFW System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low-low level in any SG is indicative of a loss of heat sink for the reactor. The level transmitters provide input to the SG Level Control System. Control/protection interaction is addressed by the use of a Median Signal Selector which prevents a single failure of a channel providing input to the control system from initiating a condition requiring protection function action. The Median Signal Selector performs this by not selecting the channels indicating the highest or lowest steam generator levels as input to the control system.

Because one failed protection instrument channel would not result in an adverse control system action, a second random protection system failure (as otherwise required by IEEE 279-1971) need not be considered.

The Steam Generator Water Level Trip Time Delay (TTD) creates additional operational margin when the plant needs it most, during escalation to power, by allowing the operator time to recover level when the primary side load is sufficiently small to allow such action. The TTD is based on continuous monitoring of primary side power through the use of vessel ΔT. Two time delays are calculated based on the number of steam generators indicating less than the Low-Low Trip Setpoint per Note 3 of Table 3.3.1-1. The magnitude of the delays decreases with increasing primary side power level, up to 50% RTP. Above 50% RTP there are no time delays for the Low-Low Level channel trips.

The algorithm for the TTD, T_s and T_m, determines the trip delay as a function of power level (P) and four constants (A through D for T_s, E through H for T_m). An allowance for the accuracy of the Eagle-21™ time base is included in the determination of the magnitude of the constants. The magnitude of the accuracy allowance is 1%, i.e., the constant values were multiplied by 0.99 to account for this potential error.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

13. Steam Generator Water Level – Low-Low (continued)

In the event of failure of a Steam Generator Water Level Channel, the channel is placed in the trip condition as input to the Solid State Protection System (SSPS) and does not affect the TTD setpoint calculations for the remaining OPERABLE channels. It is then necessary for the operator to force the use of the shorter TTD time delay by adjustment of the single steam generator time delay calculation (T_S) to match the multiple steam generator time delay calculation (T_M) for the affected protection set, through the Man-Machine Interface. Failure of the vessel ΔT channel input (failure of more than one T_H RTD or failure of both T_C RTDs) affects the TTD calculation for a protection set. This results in the requirement that the operator adjust the threshold power level for zero seconds time delay from 50% RTP to 0% RTP, through the Man Machine Interface.

The LCO requires three channels of SG Water Level – Low-Low per SG to be OPERABLE. This function initiates a reactor trip and the ESFAS function auxiliary feedwater pump start. The reactor trip feature is required to be OPERABLE in MODES 1 and 2 and the auxiliary feedwater pump start feature is required to be OPERABLE in MODES 1, 2, and 3.

In MODE 3, OPERABILITY of loop ΔT input to TTD is not required because MODE 3 $\Delta T = 0$ (by definition). The Eagle-21™ code does not allow anything less than 0. The value of ΔT is low-limited to 0.0 prior to use in the calculation of the single and multiple trip time delays.

For MODES 1 and 2, ΔT_0, as used in the Vessel ΔT Equivalent to Power represents the 100% RTP value as measured for each loop. ΔT_0 normalizes each loop's vessel ΔT to the actual operating conditions existing at the time of measurement, thus forcing the TTD to reflect the equivalent full power conditions as assumed in the accident analyses. Differences in RCS loop ΔT can be due to several factors, e.g., measured RCS loop flow greater than minimum measured flow, and slightly asymmetric power distributions between quadrants. While RCS loop flows are not expected to change with cycle life, radial power redistribution between quadrants may occur, resulting in small changes in loop specific ΔT values. Loop specific values of ΔT_0 must be determined at the beginning of each fuel cycle at full power, steady-state conditions (i.e., power distribution not affected by

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

13. Steam Generator Water Level – Low-Low (continued)

xenon transient conditions) and will be checked quarterly and updated, if required. Tolerances for ΔT_0 have been included in the determination of the Vessel ΔT Equivalent to Power.

For MODES 1, 2, and 3, channel check surveillance testing on RCS loop ΔT input to TTD is not required. There are no provisions for performing a channel check on the RCS loop ΔT for the SG Level TTD Function. The power level can only be verified by connecting the Eagle-21™ Man-Machine Interface terminal and viewing the Dynamic Information for this channel. The Eagle-21™ system uses a redundant sensor algorithm for the hot leg and cold leg inputs, and will alert the operator if a failure occurs with the sensor or input signal conditioning.

The coefficients (A, B, C, D, E, F, G, and H) shown in the equation of Note 3 represent conservative values for the calculation of the time delay (i.e., the values given are 99% of the values used for the safety analyses). For the Eagle-21™ System, these coefficients are displayed (via the Man-Machine Interface) as A, B, C and D for the single request time delay, and E, F, G and H for the multiple request time delay.

In MODE 1 or 2, when the reactor is critical, the SG Water Level – Low-Low trip must be OPERABLE. In MODES 1, 2, and 3 the normal source of water for the SGs is the Main Feedwater (MFW) System (not safety related). The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor in these MODES. The ESFAS Function of the SG Water Level – Low-Low trip must be OPERABLE in MODES 1, 2, and 3. In MODES 3, 4, 5, and 6, the SG Water Level – Low-Low trip Function does not have to be OPERABLE because the reactor is not operating or even critical.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

14. Turbine Trip

a. Turbine Trip - Low Fluid Oil Pressure

The Turbine Trip - Low Fluid Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip Function acts to minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the P-9 setpoint, approximately 50% power, will not actuate a reactor trip. Three pressure switches monitor the control oil pressure in the Turbine Electrohydraulic Control System. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure - High trip Function and RCS integrity is ensured by the pressurizer safety valves.

The LCO requires three channels of Turbine Trip - Low Fluid Oil Pressure to be OPERABLE in MODE 1 above P-9.

Below the P-9 setpoint, a turbine trip does not actuate a reactor trip. In MODE 2, 3, 4, 5, or 6, there is no potential for a turbine trip, and the Turbine Trip - Low Fluid Oil Pressure trip Function does not need to be OPERABLE.

b. Turbine Trip - Turbine Stop Valve Closure

The Turbine Trip - Turbine Stop Valve Closure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip from a power level below the P-9 setpoint, approximately 50% power. This action will not actuate a reactor trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the stop valves close. Tripping the reactor in anticipation of loss of secondary heat removal acts to minimize the pressure and temperature transient on the reactor. This trip Function will not and is not required to operate in the presence of a single channel failure. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Turbine Trip – Turbine Stop Valve Closure (continued)

Pressure – High trip Function, and RCS integrity is ensured by the pressurizer safety valves. This trip Function is diverse to the Turbine Trip – Low Fluid Oil Pressure trip Function. Each turbine stop valve is equipped with one limit switch that inputs to the RTS. If all four limit switches indicate that the stop valves are all closed, a reactor trip is initiated.

The LSSS for this Function is set to assure channel trip occurs when the associated stop valve is completely closed.

The LCO requires four Turbine Trip – Turbine Stop Valve Closure channels, one per valve, to be OPERABLE in MODE 1 above P-9. All four channels must trip to cause reactor trip.

Below the P-9 setpoint, a load rejection can be accommodated by the Steam Dump System. In MODE 2, 3, 4, 5, or 6, there is no potential for a load rejection, and the Turbine Trip – Stop Valve Closure trip Function does not need to be OPERABLE.

15. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)

The SI Input from ESFAS ensures that if a reactor trip has not already been generated by the RTS, the ESFAS automatic actuation logic will initiate a reactor trip upon any signal that initiates SI. Reactor trip is not credited in the large break LOCA. However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a reactor trip is initiated every time an SI signal is present.

Trip Setpoint and Allowable Values are not applicable to this Function. The SI Input is provided by solid state logic in the ESFAS. Therefore, there is no measurement signal with which to associate an LSSS.

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

15. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS) (continued)

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

16. Reactor Trip System Interlocks

Reactor protection interlocks are provided to ensure reactor trips are in the correct configuration for the current unit status. They back up operator actions to ensure protection system Functions are not bypassed during unit conditions under which the safety analysis assumes the Functions are not bypassed. Therefore, the interlock Functions do not need to be OPERABLE when the associated reactor trip Functions are outside the applicable MODES. These are:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when any NIS intermediate range channel indicates approximately one decade above the minimum channel reading. If both channels decrease below the setpoint, the permissive will automatically be defeated. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to increasing power above the source range; and

- on decreasing power, the P-6 interlock automatically enables the NIS Source Range Neutron Flux reactor trip.

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Intermediate Range Neutron Flux, P-6 (continued)

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux reactor trip may be blocked, and this Function would no longer be necessary. In MODE 3, 4, 5, or 6, the P-6 interlock is not required to be OPERABLE because the NIS Source Range is providing core protection.

b. Low Power Reactor Trips Block, P-7

The Low Power Reactor Trips Block, P-7 interlock is actuated by input from either the Power Range Neutron Flux, P-10, or the Turbine Impulse Pressure, P-13 interlock. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

(1) on increasing power, the P-7 interlock automatically enables reactor trips on the following Functions:

- Pressurizer Pressure - Low;
- Pressurizer Water Level - High;
- Reactor Coolant Flow - Low (in two or more RCS Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs.

These reactor trips are only required when operating above the P-7 setpoint (approximately 10% power). The reactor trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of providing sufficient natural circulation without any RCP running.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Low Power Reactor Trips Block, P-7 (continued)

(2) on decreasing power, the P-7 interlock automatically blocks reactor trips on the following Functions:

- Pressurizer Pressure - Low;
- Pressurizer Water Level - High;
- Reactor Coolant Flow - Low (in two or more RCS Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs.

Trip Setpoint and Allowable Value are not applicable to the P-7 interlock because it is a logic Function, and thus has no parameter with which to associate an LSSS.

The P-7 interlock is a logic Function with train and not channel identity. Therefore, the LCO requires one channel per train of Low Power Reactor Trips Block, P-7 interlock to be OPERABLE in MODE 1.

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint.

In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below 10% power, which is in MODE 1.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated at approximately 48% power as determined by two-out-of-four NIS power range detectors. Above approximately 48% power the P-8 interlock automatically enables the Reactor Coolant Flow - Low reactor trip on low flow in one or more RCS loops on increasing power. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than approximately 48% power. On decreasing power, the reactor trip on low flow in any loop is automatically blocked.

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1.

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

d. Power Range Neutron Flux, P-9

The Power Range Neutron Flux, P-9 interlock is actuated at approximately 50% power as determined by two-out-of-four NIS power range detectors. The LCO requirement for this Function ensures that the Turbine Trip - Low Fluid Oil Pressure and Turbine Trip - Turbine Stop Valve Closure reactor trips are enabled above the P-9 setpoint. Above the P-9 setpoint, a turbine trip will cause a load rejection beyond the combined capacity of the Steam Dump System and Rod Control System. A reactor trip is automatically initiated on a turbine trip when it is above the P-9 setpoint, to minimize the transient on the reactor.

The LCO requires four channels of Power Range Neutron Flux, P-9 interlock to be OPERABLE in MODE 1.

In MODE 1, a turbine trip could cause a load rejection beyond the capacity of the Steam Dump System, so the Power Range Neutron Flux interlock must be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Power Range Neutron Flux, P-9 (continued)

In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at a power level sufficient to have a load rejection beyond the capacity of the Steam Dump System.

e. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock is actuated at approximately 10% power, as determined by two-out-of-four NIS power range detectors. If power level falls below 10% power on 3 of 4 channels, the nuclear instrument trips will be automatically unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip. Note that blocking the reactor trip also blocks the signal to prevent automatic and manual rod withdrawal;
- on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux - Low reactor trip;
- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux reactor trip;
- the P-10 interlock provides one of the two inputs to the P-7 interlock; and
- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux - Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

e. Power Range Neutron Flux, P-10 (continued)

OPERABILITY in MODE 1 ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must be OPERABLE in MODE 2 to ensure that core protection is provided during a startup or shutdown by the Power Range Neutron Flux - Low and Intermediate Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection.

f. Turbine Impulse Pressure, P-13

The Turbine Impulse Pressure, P-13 interlock is actuated when the pressure at the inlet of the high pressure turbine is greater than approximately 10% of the rated full load pressure. This is determined by one-out-of-two pressure detectors. The LCO requirement for this Function ensures that one of the inputs to the P-7 interlock is available.

The LCO requires two channels of Turbine Impulse Pressure, P-13 interlock to be OPERABLE in MODE 1.

The Turbine Impulse Pressure, P-13 interlock must be OPERABLE when the turbine generator is operating. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

17. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of individual trip mechanisms. The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of all trip breakers associated with a single RTS logic train that are racked in, closed, and capable of supplying power to the CRD System. Thus, the train may consist of the main breaker, bypass breaker, or main breaker and bypass breaker, depending upon the system configuration. Two OPERABLE trains ensure no single random failure can disable the RTS trip capability.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

17. Reactor Trip Breakers (continued)

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the RTBs or associated bypass breakers are closed, and the CRD System is capable of rod withdrawal.

18. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the CRD System, or declared inoperable under Function 17 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the RTBs or associated bypass breakers are closed, and the CRD System is capable of rod withdrawal.

19. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 17 and 18) and Automatic Trip Logic (Function 19) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. Each RTB is equipped with a bypass breaker to allow testing of the trip breaker while the unit is at power. The reactor trip signals generated by the RTS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RTS Automatic Trip Logic to be OPERABLE. Having two OPERABLE channels ensures that random failure of a single logic channel will not prevent reactor trip.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

19. Automatic Trip Logic (continued)

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the RTBs or associated bypass breakers are closed, and the CRD System is capable of rod withdrawal.

The RTS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.1-1.

In the event a channel's NTSP is found non-conservative with respect to the Allowable Value, or the channel is not functioning as required, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all RTS protection functions. Condition A addresses the situation where one or more required channels for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

(continued)

BASES

ACTIONS (continued)

B.1, B.2.1, and B.2.

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation of the SSPS for this Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. In this Condition, the remaining OPERABLE channel is adequate to perform the safety function.

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 48-hour Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 additional hours (54 hours total time) followed by opening the RTBs within 1 additional hour (55 hours total time). The 6 additional hours to reach MODE 3 and the 1 hour to open the RTBs are reasonable, based on operating experience, to reach MODE 3 and open the RTBs from full power operation in an orderly manner and without challenging plant systems. With the RTBs open and the plant in MODE 3, this trip Function is no longer required to be OPERABLE.

C.1 and C.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal:

- Manual Reactor Trip;
- RTBs;
- RTB Undervoltage and Shunt Trip Mechanisms; and
- Automatic Trip Logic.

This action addresses the train orientation of the SSPS for these Functions. With one channel or train inoperable, the inoperable channel or train must be restored to OPERABLE status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the plant must be placed in a MODE in which the requirement does not apply. To achieve this status, the RTBs

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

must be opened within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With the RTBs open, these Functions are no longer required. The Completion Time is reasonable considering that in this Condition, the remaining OPERABLE channel or train is adequate to perform the safety function, and given the low probability of an event occurring during this interval.

D.1.1, D.1.2, D.2.1, D.2.2, and D.3

Condition D applies to the Power Range Neutron Flux - High Function.

The NIS power range detectors provide input to the CRD System and the SG Water Level Control System and, therefore, have a two-out-of-four trip logic. A known inoperable channel must be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three logic for actuation. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 14.

In addition to placing the inoperable channel in the tripped condition, THERMAL POWER must be reduced to ≤ 75% RTP within 78 hours. Reducing the power level prevents operation of the core with radial power distributions beyond the design limits. With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost.

As an alternative to the above actions, the inoperable channel can be placed in the tripped condition within 72 hours and the QPTR monitored once every 12 hours as per SR 3.2.4.2, QPTR verification. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels ≥ 75% RTP. The 12 hour Frequency is consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

As an alternative to the above actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Seventy-eight hours are allowed to place the plant in MODE 3. The 78 hour Completion Time includes 72 hours for channel corrective maintenance and an additional 6 hours for the MODE reduction as required by Required Action D.3. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

(continued)

BASES

ACTIONS

D.1.1, D.1.2, D.2.1, D.2.2, and D.3 (continued)

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypass condition for up to 12 hours while performing routine surveillance testing of other channels. The Note also allows placing the inoperable channel in the bypass condition to allow setpoint adjustments of other channels when required to reduce the setpoint in accordance with other Technical Specifications. The 12 hour time limit is justified in Reference 14.

Required Action D.2.2 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux channel which renders the High Flux trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using the PDMS once per 12 hours may not be necessary.

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux - Low; and
- Power Range Neutron Flux - High Positive Rate.

A known inoperable channel must be placed in the tripped condition within 72 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 14.

If the inoperable channel cannot be placed in the trip condition within the specified Completion Time, the plant must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the plant in MODE 3. Six hours is a reasonable time, based on operating experience, to place the plant in MODE 3 from full power in an orderly manner and without challenging plant systems.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 14.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

Condition F applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 2 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or increase THERMAL POWER above the P-10 setpoint. The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in reactor trip.

G.1 and G.2

Condition G applies to two inoperable Intermediate Range Neutron Flux trip channels in MODE 2 when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint. Required Actions specified in this Condition are only applicable when channel failures do not result in reactor trip. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also reduce THERMAL POWER below the P-6 setpoint within two hours. Below P-6, the Source Range Neutron Flux channels will be able to monitor the core power level. The Completion Time of 2 hours will allow a slow and controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the NIS Intermediate Range Neutron Flux trip.

(continued)

BASES

ACTIONS (continued)

H.1

Condition H applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is below the P-6 setpoint and one or two channels are inoperable. Below the P-6 setpoint, the NIS source range performs the monitoring and protection functions. The inoperable NIS intermediate range channel(s) must be returned to OPERABLE status prior to increasing power above the P-6 setpoint. The NIS intermediate range channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10.

I.1

Condition I applies to one inoperable Source Range Neutron Flux trip channel when in MODE 2, below the P-6 setpoint, and performing a reactor startup. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the two channels inoperable, operations involving positive reactivity additions shall be suspended immediately.

This will preclude any power escalation. With only one source range channel OPERABLE, core protection is severely reduced and any actions that add positive reactivity to the core must be suspended immediately.

J.1

Condition J applies to two inoperable Source Range Neutron Flux trip channels when in MODE 2, below the P-6 setpoint, and performing a reactor startup, or in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With both source range channels inoperable, the RTBs must be opened immediately. With the RTBs open, the core is in a more stable condition and the plant enters Condition L.

(continued)

BASES

ACTIONS (continued)

K.1 and K.2

Condition K applies to one inoperable Source Range Neutron Flux trip channel in MODE 3, 4, or 5 with the RTBs closed and the CRD System capable of rod withdrawal. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the source range channels inoperable, 48 hours is allowed to restore it to an OPERABLE status. If the channel cannot be returned to an OPERABLE status, 1 additional hour is allowed to open the RTBs. Once the RTBs are open, the core is in a more stable condition and the plant enters Condition L. The allowance of 48 hours to restore the channel to OPERABLE status, and the additional hour to open the RTBs, are justified in Reference 7.

L.1, L.2, and L.3

Condition L applies when the required Source Range Neutron Flux channel is inoperable in MODE 3, 4, or 5 with the RTBs open. With the unit in this Condition, the NIS source range performs the monitoring and protection functions. With the required source range channel inoperable, operations involving positive reactivity additions shall be suspended immediately. This will preclude any power escalation. In addition to suspension of positive reactivity additions, all valves that could add unborated water to the RCS must be closed within 1 hour as specified in LCO 3.9.2. The isolation of unborated water sources will preclude a boron dilution accident.

Also, the SDM must be verified within 1 hour and once every 12 hours thereafter as per SR 3.1.1.1, SDM verification. With no source range channels OPERABLE, core protection is severely reduced. Verifying the SDM within 1 hour allows sufficient time to perform the calculations and determine that the SDM requirements are met. The SDM must also be verified once per 12 hours thereafter to ensure that the core reactivity has not changed. Required Action L.1 precludes any positive reactivity additions; therefore, core reactivity should not be increasing, and a 12 hour Frequency is adequate. The Completion Times of within 1 hour and once per 12 hours are based on operating experience in performing the Required Actions and the knowledge that unit conditions will change slowly.

(continued)

BASES

ACTIONS (continued)

M.1 and M.2

Condition M applies to the following reactor trip Functions:

- Undervoltage RCPs; and
- Underfrequency RCPs.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a reactor trip above the P-7 setpoint and below the P-8 setpoint. These Functions do not have to be OPERABLE below the P-7 setpoint because there are no loss of flow trips below the P-7 setpoint. The 72 hours allowed to place the channel in the tripped condition is justified in Reference 14. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition M.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 14.

N.1 and N.2

Condition N applies to the Reactor Coolant Flow - Low reactor trip Function. With one channel inoperable, the inoperable channel must be placed in trip within 72 hours. Placing the channel in the tripped condition when above the P-8 setpoint results in a partial trip condition requiring only one additional channel in the same loop to initiate a reactor trip. Two tripped channels in each of two RCS loops are required to initiate a reactor trip when below the P-8 setpoint and above the P-7 setpoint. This trip Function does not have to be OPERABLE below the P-7 setpoint because there is no loss of flow trip below the P-7 setpoint. There is insufficient heat production to generate DNB conditions below the P-7 setpoint. The 72 hours allowed to place the channel in the tripped

(continued)

BASES

ACTIONS

N.1 and N.2 (continued)

condition is justified in Reference 14. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Function associated with Condition N.

The Required Actions have been modified by a Note that allows placing an inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The Note also allows a channel to be placed in bypass for up to 12 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 12 hour time limit is justified in Reference 14.

O.1 and O.2

Condition O applies to Turbine Trip on Low Fluid Oil Pressure. With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours. Placing a channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the tripped condition, then power must be reduced below the P-9 setpoint within the next 4 hours. The 72 hours allowed to place the inoperable channel in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 14.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in Reference 14.

(continued)

BASES

ACTIONS (continued)

P.1 and P.2

Condition P applies to the SI Input from ESFAS reactor trip and the RTS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RTS for these Functions. With one train inoperable, 24 hours are allowed to restore the train to OPERABLE status (Required Action P.1) or the plant must be placed in MODE 3 within the next 6 hours. The Completion Time of 24 hours (Required Action P.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The 24 hours allowed to restore the inoperable RTS Automatic Trip Logic train to OPERABLE status is justified in Reference 14. The Completion Time of 6 hours (Required Action P.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

The Required Actions have been modified by a Note that allows bypassing one train up to 4 hours for surveillance testing, provided the other train is OPERABLE.

Q.1 and Q.2

Condition Q applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RTS for the RTBs. With one train inoperable, 24 hours are allowed for train corrective maintenance to restore the train to OPERABLE status or the plant must be placed in MODE 3 within the next 6 hours. The 24 hour Completion Time is justified in Reference 15. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. Placing the Unit in Mode 3 results in Condition C entry while RTB(s) are inoperable.

The Required Actions have been modified by a Note. The Note allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. The 4 hour time limit is justified in Reference 15.

(continued)

BASES

ACTIONS (continued)

R.1 and R.2

Condition R applies to the P-6 and P-10 interlocks. With one channel inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing plant condition within 1 hour or the plant must be placed in MODE 3 within the next 6 hours. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RTS Function.

S.1 and S.2

Condition S applies to the P-7, P-8, P-9, and P-13 interlocks. With one channel inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing plant condition within 1 hour or the plant must be placed in MODE 2 within the next 6 hours. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging plant systems.

T.1, T.2.1, and T.2.2

Condition T applies to the RTB Undervoltage and Shunt Trip Mechanisms, or diverse trip features, in MODES 1 and 2. With one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours or the plant must be placed in a MODE where the requirement does not apply. This is accomplished by placing the plant in MODE 3 within the next 6 hours (54 hours total time) followed by opening the RTBs in 1 additional hour (55 hours total time).

The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. With the RTBs open and the plant in MODE 3, this trip Function is no longer required to be OPERABLE. The affected RTB shall not be bypassed while one of the diverse features is

(continued)

BASES

ACTIONS

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

inoperable except for the time required to perform maintenance to one of the diverse features. The allowable time for performing maintenance of the diverse features is 2 hours for the reasons stated under Condition Q.

The Completion Time of 48 hours for Required Action T.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

U.1.1, U.1.2, and U.2

Condition U applies to the Steam Generator Water Level – Low-Low reactor trip Function.

A known inoperable channel must be restored to OPERABLE status or placed in the tripped condition within 72 hours. Placing the channel in the tripped condition requires only one-out-of-two logic for actuation of the two-out-of-three trips. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 14.

If a channel fails, it is placed in the tripped condition and does not affect the TTD setpoint calculations for the remaining OPERABLE channels. It is then necessary for the operator to force the use of the shorter TTD time delay by adjustment of the single steam generator time delay calculation (T_S) to match the multiple steam generator time delay calculation (T_M) for the affected protection set, through the Man Machine Interface.

If the inoperable channel cannot be restored or placed in the tripped condition within the specified Completion Time, the plant must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the plant in MODE 3. Six hours is a reasonable time, based on operating experience, to place the plant in MODE 3 from MODE 1 from full power in an orderly manner and without challenging plant systems.

The Required Actions have been modified by a Note that allows placing an inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The Note also allows a channel to be placed in bypass for up to 12 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 12 hour time limit is justified in Reference 14.

(continued)

BASES

ACTIONS (continued)

V.1 and V.2

Condition V applies to the Vessel ΔT Equivalent to Power reactor trip Function.

Failure of the vessel ΔT channel input (failure of more than one T_H RTD or failure of both T_C RTDs) affects the TTD calculation for a protection set. This results in the requirement that the operator adjust the threshold power level for zero seconds time delay from 50% RTP to 0% RTP, through the Man Machine Interface.

If the inoperable channel cannot be restored or the threshold power level for zero seconds time delay adjusted within the specified Completion Time, the plant must be placed in a MODE where these Functions are not required to be OPERABLE. An additional 6 hours is allowed to place the plant in MODE 3. Six hours is a reasonable time, based on operating experience, to place the plant in MODE 3 from MODE 1 from full power in an orderly manner and without challenging plant systems.

The Required Actions have been modified by a Note that allows placing an inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The Note also allows a channel to be placed in bypass for up to 12 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 12 hour time limit is justified in Reference 14.

W.1 and W.2

Condition W applies to the following reactor trip functions:

- Overtemperature ΔT;
- Overpower ΔT; and
- Pressurizer Pressure - High.

A known inoperable channel must be placed in the tripped condition within 72 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The 72 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 14.

(continued)

BASES

ACTIONS

W.1 and W.2 (continued)

If the operable channel cannot be restored or placed in the trip condition within the specified Completion Time, the plant must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the plant in MODE 3. Six hours is a reasonable time, based on operating experience, to place the plant in MODE 3 from full power in an orderly manner and without challenging plant systems.

The Required Actions have been modified by a Note that allows placing an inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The Note also allows a channel to be placed in bypass for up to 12 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 12 hour time limit is justified in Reference 14.

X.1 and X.2

Condition X applies to the following reactor trip functions:

- Pressurizer Pressure - Low; and
- Pressurizer Water Level - High.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 72 hours. Placing the channel in the tripped condition when above the P-7 setpoint results in a partial trip condition requiring only one additional channel to initiate a reactor trip. These Functions do not have to be OPERABLE below the P-7 setpoint since there is insufficient heat production to generate DNB conditions below the P-7 setpoint. The 72 hours allowed to place the channel in the tripped condition is justified in Reference 14. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition X.

(continued)

BASES

ACTIONS

X.1 and X.2 (continued)

The Required Actions have been modified by a Note that allows placing an inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The Note also allows a channel to be placed in bypass for up to 12 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 12 hour time limit is justified in Reference 14.

Y.1 and Y.2

Condition Y applies to the Turbine Trip on Stop Valve Closure. With one, two or three channels inoperable, the inoperable channels must be placed in the trip condition within 72 hours. Since all the valves must be tripped (not fully open) in order for the reactor trip signal to be generated, it is acceptable to place more than one Turbine Stop Valve Closure channel in the trip condition. With one or more channels in the trip condition, a partial reactor trip condition exists. All of the remaining Turbine Stop Valve channels are required to actuate in order to initiate a reactor trip. If a channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced to below the P-9 setpoint within the next 4 hours. The 72 hours allowed to place an inoperable channel in the trip condition and the 4 hours allowed for reducing power are justified in Reference 14.

Z.1

With two RTS trains inoperable, no automatic capability is available to shutdown the reactor, and immediate plant shutdown in accordance with the LCO 3.0.3 is required.

BASES

SURVEILLANCE REQUIREMENTS

The SRs for each RTS Function are identified by the Surveillance Requirements column of Table 3.3.1-1 for that Function.

A Note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RTS Functions.

Note that each channel of process protection supplies both trains of the RTS. When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV. The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

The protection Functions associated with the EAGLE-21™ Process Protection System have an installed bypass capability, and may be tested in either the trip or bypass mode, as approved in Reference 7. When testing is performed in the bypass mode, the SSPS input relays are not operated, as justified in Reference 9. The input relays are checked during the CHANNEL CALIBRATION every 18 months.

SR 3.3.1.1

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

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

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the NIS channel output every 24 hours. If the calorimetric exceeds the NIS channel output by > 2% RTP, the NIS is not declared inoperable, but must be adjusted. If the NIS channel output cannot be properly adjusted, the channel is declared inoperable.

Two Notes modify SR 3.3.1.2. The first Note indicates that the NIS channel output shall be adjusted consistent with the calorimetric results if the absolute difference between the NIS channel output and the calorimetric is > 2% RTP. The second Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 12 hours is allowed for performing the first Surveillance after reaching 15% RTP. At lower power levels, calorimetric data are inaccurate.

The Frequency of every 24 hours is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Together these factors demonstrate the change in the absolute difference between NIS and heat balance calculated powers rarely exceeds 2% in any 24 hour period.

In addition, control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

SR 3.3.1.3 compares the power distribution measurement to the NIS channel AFD output every 31 EFPD. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted. If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the Overtemperature ΔT Function. The incore power distribution measurement is obtained using the OPERABLE Power Distribution Monitoring System (PDMS) (Ref. 16).

Two Notes modify SR 3.3.1.3. Note 1 indicates that the excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%. Note 2 clarifies that the Surveillance is required only if reactor power is ≥ 25% RTP and that 96 hours is allowed for performing the first Surveillance after reaching 25% RTP. This surveillance is typically performed at greater than or equal to 50% RTP to ensure the results of the evaluation are more accurate and the adjustments more reliable. Ninety-six (96) hours are allowed to ensure Xenon stability and allow for instrumentation alignments.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.3 (continued)

The Frequency of every 31 EFPD is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Also, the slow changes in neutron flux during the fuel cycle can be detected during this interval.

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT every 62 days on a STAGGERED TEST BASIS. This test shall verify OPERABILITY by actuation of the end devices.

The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. Independent verification of RTB undervoltage and shunt trip Function is not required for the bypass breakers. No capability is provided for performing such a test at power. The bypass breaker test shall include a local shunt trip. A Note has been added to indicate that this test must be performed on the bypass breaker prior to placing it in service.

The Frequency of every 62 days on a STAGGERED TEST BASIS is justified in Reference 15.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested every 92 days on a STAGGERED TEST BASIS, using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection Function. The Frequency of every 92 days on a STAGGERED TEST BASIS is justified in Reference 15.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore power distribution measurement(s). If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the Overtemperature ΔT Function. The incore power distribution measurement(s) are obtained using the OPERABLE Power Distribution Monitoring System (PDMS) (Ref. 16).

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is > 50% RTP, and that 6 days is allowed for performing the first surveillance after reaching 50% RTP.

The Frequency of 92 EFPD is adequate. It is based on industry operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 184 days.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function.

Setpoints must be conservative with respect to the Allowable Values specified in Table 3.3.1-1.

The difference between the current "as found" values and the NTSP or previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

The “as found” and “as left” values must also be recorded and reviewed for consistency with the assumptions of the setpoint methodology.

SR 3.3.1.7 is modified by a Note that this test shall include verification that the P-10 interlock is in the required state for the existing unit condition.

The Frequency of 184 days is justified in Reference 15, except for Function 13. The justification for Function 13 is provided in References 9 and 15.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

SR 3.3.1.7 is modified by two Notes as identified in Table 3.3.1-1. The first Note requires evaluation of channel performance for the condition where the as found setting for the channel setpoint is outside its as found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service.

For channels determined to be OPERABLE but degraded, after returning the channel to service the channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as left setting for the channel be returned to within the as left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as left and as found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as left channel setting cannot be returned to a setting within the as left tolerance of the NTSP, then the channel shall be declared inoperable.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, except it is modified by two Notes. Note 1 provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.8 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for greater than 4 hours, this Surveillance must be performed within 4 hours after entry into MODE 3. Note 2 states that this test shall include verification that the P-6 interlock is in the required state for the existing unit condition. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within 31 days prior to reactor startup and 4 hours after reducing power below P-10 and P-6. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the source and intermediate range instrument channels. The Frequency of "Four hours after reducing power below P-10" (applicable to intermediate channels) and "Four hours after reducing power below P-6" (applicable to source range channels) allows a normal shutdown to be completed and the unit

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance. The Frequency of every 31 days thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup and 4 hours after reducing power below P-10 or P-6.

The MODE of Applicability for this surveillance is < P-10 for the intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 or < P-6 for more than 4 hours, then the testing required by this surveillance must be performed prior to the expiration of the 4 hour limit. Four hours is a reasonable time to complete the required testing or place the unit in a MODE where this surveillance is no longer required. This test ensures that the NIS source and intermediate range channels are OPERABLE channels prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10 or < P-6) for periods > 4 hours.

SR 3.3.1.8 is modified by two Notes as identified in Table 3.3.1-1. The first Note requires evaluation of channel performance for the condition where the as found setting for the channel setpoint is outside its as found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as left setting for the channel be returned to within the as left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as left and as found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as left channel setting cannot be returned to a setting within the as left tolerance of the NTSP, then the channel shall be declared inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.9

SR 3.3.1.9 is the performance of a TADOT and is performed every 92 days, as justified in Reference 7.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. Since this SR applies to RCP undervoltage and underfrequency relays, setpoint verification requires elaborate bench calibration and is accomplished during the CHANNEL CALIBRATION.

SR 3.3.1.10

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the Watts Bar setpoint methodology. The difference between the current "as found" values and the NTSP or previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

The Frequency of 18 months is based on the assumption of an 18 month calibration interval in the determination of the magnitude of sensor/transmitter drift in the setpoint methodology.

SR 3.3.1.10 is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. For channels with a trip time delay (TTD), this test shall include verification that the TTD coefficients are adjusted correctly.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

SR 3.3.1.10 is modified by two Notes as identified in Table 3.3.1-1. The first Note requires evaluation of channel performance for the condition where the as found setting for the channel setpoint is outside its as found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as left setting for the channel be returned to within the as left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as left and as found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as left channel setting cannot be returned to a setting within the as left tolerance of the NTSP, then the channel shall be declared inoperable.

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 18 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the power range neutron detectors consists of a normalization of the detectors based on a power calorimetric performed above 15% RTP. The CHANNEL CALIBRATION for the source range and intermediate range neutron detectors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. This Surveillance is not required for the NIS power range detectors for entry into MODE 2 or 1, and is not required for the NIS intermediate range detectors for entry into MODE 2, because the unit must be in at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.11 (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 Surveillance when performed on the 18-month Frequency.

SR 3.3.1.11 is modified by two Notes as identified in Table 3.3.1-1. The first Note requires evaluation of channel performance for the condition where the as found setting for the channel setpoint is outside its as found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as left setting for the channel be returned to within the as left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as left and as found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as left channel setting cannot be returned to a setting within the as left tolerance of the NTSP, then the channel shall be declared inoperable.

SR 3.3.1.12

SR 3.3.1.12 is the performance of a COT of RTS interlocks every 18 months.

The Frequency is based on the known reliability of the interlocks and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.13

SR 3.3.1.13 is the performance of a TADOT of the Manual Reactor Trip, Reactor Trip from Manual SI, and the Reactor Trip from Automatic SI Input from ESFAS. This TADOT is performed every 18 months. The test shall independently verify the OPERABILITY of the undervoltage and shunt trip mechanisms for these Reactor Trip Functions for the Reactor Trip Breakers. The test shall also verify OPERABILITY of the Reactor Trip Bypass Breakers for these Functions. Independent verification of the Reactor Trip Bypass Breakers undervoltage and shunt trip mechanisms is not required.

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. The Functions affected have no setpoints associated with them.

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4, except that this test is performed prior to exceeding the P-9 interlock whenever the unit has been in Mode 3. This Surveillance is not required if it has been performed within the previous 31 days. Verification of the Trip Setpoint does not have to be performed for this Surveillance. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to exceeding the P-9 interlock.

SR 3.3.1.15

SR 3.3.1.15 verifies that the individual channel/train actuation response times are less than or equal to the maximum values assumed in the accident analysis. Response time testing acceptance criteria are included in Technical Requirements Manual, Section 3.3.1 (Ref. 8). Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the trip setpoint value at the sensor to the point at which the equipment reaches the required functional state (i.e., control and shutdown rods fully inserted in the reactor core).

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.15 (continued)

For channels that include dynamic transfer Functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer Function set to one, with the resulting measured response time compared to the appropriate FSAR response time. Alternately, the response time test can be performed with the time constants set to their nominal value, provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of sequential tests such that the entire response time is measured.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) in place, onsite, or offsite (e.g. vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A Revision 2, “Elimination of Pressure Sensor Response Time Testing Requirements” (Ref. 11), provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

WCAP-14036-P-A, Revision 1, “Elimination of Periodic Protection Channel Response Time Tests” (Ref. 12), provides the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time. The allocations for sensor, signal conditioning and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components identified in the WCAP may be replaced without verification testing. One example where response time could be affected is replacing the sensing assembly of a transmitter.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.15 (continued)

As appropriate, each channel's response must be verified every 18 months on a STAGGERED TEST BASIS. Testing of the final actuation devices is included in the testing. Response times cannot be determined during unit operation because equipment operation is required to measure response times. Experience has shown that these components usually pass this surveillance when performed at the 18-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.3.1.15 is modified by a Note stating that neutron detectors are excluded from RTS RESPONSE TIME testing. This Note is necessary because of the difficulty in generating an appropriate detector input signal. Excluding the detectors is acceptable because the principles of detector operation ensure a virtually instantaneous response.

REFERENCES

1. Watts Bar FSAR, Section 6.0, "Engineered Safety Features."
2. Watts Bar FSAR, Section 7.0, "Instrumentation and Controls."
3. Watts Bar FSAR, Section 15.0, "Accident Analysis."
4. Institute of Electrical and Electronic Engineers, IEEE-279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," April 5, 1972.
5. 10 CFR Part 50.49, "Environmental Qualifications of Electric Equipment Important to Safety for Nuclear Power Plants."
6. Regulatory Guide 1.105, "Setpoints for Safety Related Instrumentation," Revision 3.
7. WCAP-10271-P-A, Supplement 1, and Supplement 2, Rev. 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," May 1986 and June 1990.
8. Watts Bar Technical Requirements Manual, Section 3.3.1, "Reactor Trip System Response Times."
9. Evaluation of the applicability of WCAP-10271-P-A, Supplement 1, and Supplement 2, Revision 1, to Watts Bar, Westinghouse Letter WAT-D-10128.

(continued)

BASES

REFERENCES (continued)

10. Deleted

11. WCAP-13632-P-A Revision 2, “Elimination of Pressure Sensor Response Time Testing Requirements,” January 1996

12. WCAP-14036-P-A, Revision 1, “Elimination of Periodic Protection Channel Response Time Tests,” October 1998.

13. Deleted.

14. WCAP-14333 P-A, Revision 1, “Probabilistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times,” October 1998.

15. WCAP-15376-P-A, Revision 1, “Risk Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times,” March 2003

16. WCAP-12472-P-A, “BEACON™ Core Monitoring and Operations Support System,” August 1994 (Addendum 2, April 2002).

17. TVA Calculation WBPE0689009007, “Demonstrated Accuracy Calculation for Reactor Coolant Pump Undervoltage.”

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the ESFAS, as well as specifying LCOs on other reactor system parameters and equipment performance.

Technical Specifications are required by 10 CFR 50.36 to include LSSS for variables that have significant safety functions. LSSS are defined by the regulation as “Where a LSSS is specified for a variable on which a safety limit has been placed, the setting must be chosen so that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded.” The Analytical Limit is the limit of the process variable at which a protective action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protection channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur.

The NTSP specified in Table 3.3.2-1 is a predetermined setting for a protection channel chosen to ensure automatic actuation prior to the process variable reaching the Analytical Limit and thus ensuring that the SL would not be exceeded. As such, the NTSP accounts for uncertainties in setting the channel (e.g., calibration), uncertainties in how the channel might actually perform (e.g., repeatability), changes in the point of action of the channel over time (e.g., drift during surveillance intervals), and any other factors which may influence its actual performance (e.g., harsh accident environments). In this manner, the NTSP ensures that SLs are not exceeded. Therefore, the NTSP meets the definition of an LSSS (Ref. 6).

(continued)

BASES

BACKGROUND (continued)

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "... being capable of performing its safety functions(s)." Relying solely on the NTSP to define OPERABILITY in Technical Specifications would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as found" value of a protection channel setting during a surveillance. This would result in Technical Specification compliance problems, as well as reports and corrective actions required by the rule which are not necessary to ensure safety. For example, an automatic protection channel with a setting that has been found to be different from the NTSP due to some drift of the setting may still be OPERABLE since drift is to be expected. This expected drift would have been specifically accounted for in the setpoint methodology for calculating the NTSP and thus the automatic protective action would still have ensured that the SL would not be exceeded with the "as found" setting of the protection channel. Therefore, the channel would still be OPERABLE since it would have performed its safety function and the only corrective action required would be to reset the channel within the established as left tolerance around the NTSP to account for further drift during the next surveillance interval.

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits are:

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling (DNB),

2. Fuel centerline melt shall not occur, and

3. The RCS pressure SL of 2735 psig (2750 psia) shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 50 and 10 CFR 100 criteria during AOOs.

Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit during accidents is that offsite dose shall be maintained within an acceptable fraction of 10 CFR 100 limits. Different accident categories are allowed a different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

(continued)

BASES

BACKGROUND (continued)

The ESFAS instrumentation is segmented into three distinct but interconnected modules as identified below:

- Field transmitters or process sensors: provide a measurable electronic signal or contact actuation based on the physical characteristics of the parameter being measured;

- Signal processing equipment including process protection system, and field contacts: provide analog to digital conversion (Digital Protection System), signal conditioning, setpoint comparison, process algorithm actuation (Digital Protection System), compatible electrical signal output to protection system channels, and control board / control room / miscellaneous indications; and

- Solid State Protection System (SSPS) including input, logic, and output bays: initiates the proper unit shutdown or engineered safety feature (ESF) actuation in accordance with the defined logic and based on the bistable, setpoint comparators, or contact outputs from the signal process control and protection system.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as five, field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the ESFAS are shared with the Reactor Trip System (RTS). In some cases, the same channels also provide control system inputs. To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the NTSP and Allowable Value. The OPERABILITY of each transmitter or sensor is determined by either “as found” calibration data evaluated during the CHANNEL CALIBRATION or by qualitative assessment of field transmitter or sensor as related to the channel behavior observed during performance of the CHANNEL CHECK.

(continued)

BASES

BACKGROUND (continued)

Signal Processing Equipment

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides analog to digital conversion (Digital Protection System), signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with NTSPs derived from Analytical Limits established by the safety analyses. Analytical Limits are defined in FSAR, Chapter 6, (Ref. 1), Chapter 7 (Ref. 2), and Chapter 15 (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a setpoint comparator or contact is forwarded to the SSPS for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the SSPS, while others provide input to the SSPS, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the SSPS and a control function, four channels with two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation.

These requirements are described in IEEE-279-1971 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2.

(continued)

BASES

BACKGROUND (continued)

Allowable Values and Nominal Trip Setpoints

The trip setpoints used in the bistables, setpoint comparators, or contact outputs are based on the analytical limits defined in Reference 2. The calculation of the Nominal Trip Setpoints specified in Table 3.3.2-1 is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the NTSPs specified in Table 3.3.2-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits.

A detailed description of the methodology used to calculate NTSPs and as left and as found tolerance bands is provided in Reference 2. All of the known uncertainties applicable for each channel are factored into the determination of each NTSP and corresponding Allowable Value. The nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. The Allowable Value serves as the as found Technical Specification OPERABILITY limit for the purpose of the COT.

The NTSP is the value at which the bistables are set and is the expected value to be achieved during calibration. The NTSP value is the LSSS and ensures the safety analysis limits are met for the surveillance interval selected when a channel is adjusted based on stated channel uncertainties. Any bistable is considered to be properly adjusted when the "as left" setpoint NTSP value is within the as left tolerance band for CHANNEL CALIBRATION uncertainty allowance (i.e., ± rack calibration and comparator setting uncertainties). The NTSP value is therefore considered a "nominal value" (i.e., expressed as a value without inequalities) for the purposes of the COT and CHANNEL CALIBRATION.

Nominal Trip Setpoints, in conjunction with the use of as left and as found tolerances, together with the requirements of the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed.

Note that the Allowable Values listed in Table 3.3.2-1 are the least conservative value of the as found setpoint that a channel can have during a periodic CHANNEL CALIBRATION, COT, or a TADOT.

(continued)

BASES

BACKGROUND (continued)

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of Reference 2. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section. The Process Protection System is designed to permit any one channel to be tested and maintained at power in a bypassed mode. If a channel has been bypassed for any purpose, the bypass is continuously indicated in the control room.

Solid State Protection System

The SSPS equipment is used for the decision logic processing of outputs from the signal processing equipment. To meet the redundancy requirements, two trains of SSPS, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements.

The SSPS performs the decision logic for most ESF equipment actuation; generates the electrical output signals that initiate the required actuation; and provides the status, permissive, and annunciator output signals to the main control room of the unit.

The outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic matrices that represent combinations indicative of various transients. If a required logic matrix combination is completed, the system will send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Each SSPS train has a built in testing channel that can automatically test the decision logic matrix functions and the actuation channels while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed. The testing channel is semiautomatic to minimize testing time.

(continued)

BASES

BACKGROUND (continued)

Solid State Protection System (continued)

The actuation of most ESF components is accomplished through master and slave relays. Some ESF components are actuated by relay logic. The SSPS energizes the master relays appropriate for the condition of the unit. Each master relay then energizes one or more slave relays, which then cause actuation of the end devices. The master and slave relays are routinely tested to ensure operation. The test of the master relays energizes the relay, which then operates the contacts and applies a low voltage to the associated slave relays. The low voltage is not sufficient to actuate the slave relays but only demonstrates signal path continuity. The SLAVE RELAY TEST actuates the devices if their operation will not interfere with continued unit operation. For the latter case, actual component operation is prevented by the SLAVE RELAY TEST circuit, and slave relay contact operation is verified by a continuity check of the circuit containing the slave relay.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer Pressure - Low is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are implicitly credited in the safety analysis and the NRC staff approved licensing basis for the unit. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

Permissive and interlock setpoints allow the blocking of trips during plant startups, and restoration of trips when the permissive conditions are not satisfied, but they are not explicitly modeled in the Safety Analyses. These permissives and interlocks ensure that the starting conditions are consistent with the safety analysis, before preventive or mitigating actions occur. Because these permissives or interlocks are only one of multiple conservative starting assumptions for the accident analysis, they are generally considered as nominal values without regard to measurement accuracy.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires all instrumentation performing an ESFAS Function listed in Table 3.3.2-1 in the accompanying LCO, to be OPERABLE. The Allowable Value specified in Table 3.3.2-1 is the least conservative value of the as found setpoint that the channel can have when tested, such that a channel is OPERABLE if the as found setpoint is within the as found tolerance and is conservative with respect to the Allowable Value during the CHANNEL CALIBRATION or CHANNEL OPERATIONAL TEST (COT). As such, the Allowable Value differs from the NTSP by an amount greater than or equal to the expected instrument channel uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the channel (NTSP) will ensure that a SL is not exceeded at any given point of time as long as the channel has not drifted beyond expected tolerances during the surveillance interval. Note that, although the channel is OPERABLE under these circumstances, the trip setpoint must be left adjusted to a value within the as left tolerance, in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned (as found criteria).

If the actual setting of the channel is found to be conservative with respect to the Allowable Value but is beyond the as found tolerance band, the channel is OPERABLE but degraded. The degraded condition of the channel will be further evaluated during performance of the SR. This evaluation will consist of resetting the channel setpoint to the NTSP (within the allowed tolerance) and evaluating the channel response. If the channel is functioning as required and expected to pass the next surveillance, then the channel can be restored to service at the completion of the surveillance. After the surveillance is completed, the channel as found condition will be entered into the Corrective Action Program for further evaluation.

A trip setpoint may be set more conservative than the NTSP as necessary in response to plant conditions. However, in this case, the operability of this instrument must be verified based on the field setting and not the NTSP. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO generally requires OPERABILITY of four or three channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three and the two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing an ESFAS initiation. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS.

The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents.

ESFAS protection functions are as follows:

1. Safety Injection

   Safety Injection (SI) provides two primary functions:

   1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F); and

   2. Boration to ensure recovery and maintenance of SDM (k_{eff} < 1.0).

   These functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The SI signal is also used to initiate other Functions such as:

   - Phase A Isolation;
   - Containment Vent Isolation;
   - Reactor Trip;
   - Turbine Trip;
   - Feedwater Isolation;
   - Start of all auxiliary feedwater (AFW) pumps;
   - Control room ventilation isolation; and
   - Enabling automatic switchover of Emergency Core Cooling Systems (ECCS) suction to containment sump.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1. Safety Injection (continued)

These other functions ensure:

- Isolation of non-essential systems through containment penetrations;
- Trip of the turbine and reactor to limit power generation;
- Isolation of main feedwater (MFW) to limit secondary side mass losses;
- Start of AFW to ensure secondary side cooling capability;
- Isolation of the control room to ensure habitability; and
- Enabling ECCS suction from the refueling water storage tank (RWST) switchover on low RWST level to ensure continued cooling via use of the containment sump.

a. Safety Injection - Manual Initiation

The LCO requires one channel per train to be OPERABLE. The operator can initiate SI at any time by using either of two switches in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO for the Manual Initiation Function ensures the proper amount of redundancy is maintained in the manual ESFAS actuation circuitry to ensure the operator has manual ESFAS initiation capability.

Each channel consists of one hand switch and the interconnecting wiring to the actuation logic cabinet. Each hand switch actuates both trains. This configuration does not allow testing at power.

b. Safety Injection - Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment, Control Room Emergency Ventilation System (CREVS), and Auxiliary Building Gas Treatment System (ABGTS).

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Safety Injection - Automatic Actuation Logic and Actuation Relays (continued)

Manual and automatic initiation of SI must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. Manual Initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a SI, actuation is simplified by the use of the manual actuation hand switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation.

These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Unit pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

c. Safety Injection - Containment Pressure - High

This signal provides protection against the following accidents:

- SLB inside containment;
- LOCA; and
- Feed line break inside containment.

Containment Pressure - High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic. The transmitters (d/p cells) and electronics are located outside of containment, inside the containment annulus, with the sensing line (high pressure side of the transmitter) located inside containment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Safety Injection - Containment Pressure - High (continued)

Thus, the high pressure Function will not experience any adverse environmental conditions and the NTSP reflects only steady state instrument uncertainties.

Containment Pressure - High must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment.

d. Safety Injection - Pressurizer Pressure - Low

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) relief or safety valve;
- SLB;
- Inadvertent opening of a pressurizer relief or safety valve;
- LOCAs; and
- SG Tube Rupture.

Three protection channels are necessary to satisfy the protective Function requirements.

The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment, rod ejection). Therefore, the NTSP reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 (above P-11) to mitigate the consequences of an HELB inside containment. This signal may be manually blocked by the operator below the P-11 setpoint. Automatic SI actuation below this pressure setpoint is then performed by the Containment Pressure - High signal.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Safety Injection - Pressurizer Pressure - Low (continued)

This Function is not required to be OPERABLE in MODE 3 below the P-11 setpoint. Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. Safety Injection - Steam Line Pressure - Low

Steam Line Pressure - Low provides protection against the following accidents:

- SLB;
- Feed line break; and
- Inadvertent opening of an SG relief or an SG safety valve.

Steam Line Pressure - Low provides no input to any control functions. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the protective requirements with a two-out-of-three logic on each steam line.

Since some of the transmitters are located inside the steam valve vaults, it is possible for them to experience adverse environmental conditions during a secondary side break. Therefore, the NTSP reflects both steady state and adverse environmental instrument uncertainties. This Function has lead/lag compensation with a lead/lag ratio of 50/5.

Steam Line Pressure - Low must be OPERABLE in MODES 1, 2, and 3 (above P-11) when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11, feed line break is not a concern. Inside Containment SLB will be terminated by automatic SI actuation via Containment Pressure - High, and outside containment SLB will be terminated by the Steam Line Pressure - Negative Rate - High signal for steam line isolation. This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to cause an accident.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. Containment Spray

Containment Spray provides one primary Function; it lowers containment pressure and temperature after an HELB in containment.

This function is necessary to:

- Ensure the pressure boundary integrity of the containment structure; and
- Limit the release of radioactive iodine to the environment in the event of a failure of the containment structure.

The containment spray actuation signal starts the containment spray pumps and aligns the discharge of the pumps to the containment spray nozzle headers in the upper levels of containment. Water is initially drawn from the RWST by the containment spray pumps. When the RWST reaches the low level setpoint, the spray pump suctions are shifted to the containment sump if continued containment spray is required. Containment spray is actuated manually or by Containment Pressure - High High.

a. Containment Spray - Manual Initiation

The operator can initiate containment spray at any time from the control room by simultaneously turning two containment spray actuation switches in the same train. Because an inadvertent actuation of containment spray could have such serious consequences, two switches must be turned simultaneously to initiate containment spray. There are two sets of two switches each in the control room. Simultaneously turning the two switches in either set will actuate containment spray in both trains in the same manner as the automatic actuation signal. Two trains of Manual Initiation switches are required to be OPERABLE to ensure no single failure disables the Manual Initiation Function. Note that Manual Initiation of containment spray also actuates Phase B containment isolation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Containment Spray - Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of containment spray must be OPERABLE in MODES 1, 2, and 3 when there is a potential for an accident to occur, and sufficient energy in the primary or secondary systems to pose a threat to containment integrity due to overpressure conditions. Manual initiation is also required in MODE 4, even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. However, because of the large number of components actuated on a containment spray, actuation is simplified by the use of the manual actuation hand switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary and secondary systems to result in containment overpressure. In MODES 5 and 6, there is also adequate time for the operators to evaluate unit conditions and respond, to mitigate the consequences of abnormal conditions by manually starting individual components.

c. Containment Spray - Containment Pressure - High High

This signal provides protection against a LOCA or a SLB inside containment. The transmitters (d/p cells) are located outside of containment, inside the containment annulus, with the sensing line (high pressure side of the transmitter) located inside containment. The transmitters and electronics are located inside the containment annulus, but outside containment, and experience more adverse environmental conditions than if they were located outside containment altogether. However, the environmental effects are less severe than if the transmitters were located inside containment. The NTSP reflects the inclusion of both steady state instrument uncertainties and slightly more adverse environmental instrument uncertainties.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Containment Spray - Containment Pressure - High High (continued)

This is one of the few Functions that requires the output to energize to perform its required action. It is not desirable to have a loss of power actuate containment spray, since the consequences of an inadvertent actuation of containment spray could be serious. Note that this Function also has the inoperable channel placed in bypass rather than trip to decrease the probability of an inadvertent actuation.

This Function uses four channels in a two-out-of-four logic configuration. This arrangement exceeds the minimum redundancy requirements. Additional redundancy is warranted because this Function is energized to trip. Containment Pressure - High High must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary sides to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to pressurize the containment and reach the Containment Pressure - High High setpoint.

3. Containment Isolation

Containment Isolation provides isolation of the containment atmosphere, and all process systems that penetrate containment, from the environment. This Function is necessary to prevent or limit the release of radioactivity to the environment in the event of a large break LOCA.

There are two separate Containment Isolation signals, Phase A and Phase B. Phase A isolation isolates all automatically isolable process lines, except Component Cooling System (CCS) and Essential Raw Cooling Water (ERCW) System, at a relatively low containment pressure indicative of primary or secondary system leaks. For these types of events, forced circulation cooling using the reactor coolant pumps (RCPs) and SGs is the preferred (but not required) method of decay heat removal. Since the CCS is required to support RCP operation, not isolating the CCS on the low pressure Phase A signal enhances unit safety by allowing operators to use forced RCS circulation to cool the unit. Isolating the CCS on the low pressure signal may force the use of feed and bleed cooling, which could prove more difficult to control.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Containment Isolation (continued)

Phase A containment isolation is actuated automatically by SI, or manually via the automatic actuation logic. All process lines penetrating containment, with the exception of the CCS and ERCW, are isolated. CCS is not isolated at this time to permit continued operation of the RCPs with cooling water flow to the thermal barrier heat exchangers and ERCW to air or oil coolers. All process lines not equipped with remote operated isolation valves are manually closed, or otherwise isolated, prior to reaching MODE 4.

Manual Phase A Containment Isolation is accomplished by either of two switches in the control room or from local panel(s). Either switch actuates both trains. Note that manual actuation of Phase A Containment Isolation also actuates Containment Vent Isolation.

The Phase B signal isolates the CCS. This occurs at a relatively high containment pressure that is indicative of a large break LOCA or a SLB. For these events, forced circulation using the RCPs is no longer desirable. Isolating the CCS at the higher pressure does not pose a challenge to the containment boundary because the CCS is a closed loop inside containment. Although some system components do not meet all of the ASME Code requirements applied to the containment itself, the system is continuously pressurized to a pressure greater than the Phase B setpoint. Thus, routine operation demonstrates the integrity of the system pressure boundary for pressures exceeding the Phase B setpoint. Furthermore, because system pressure exceeds the Phase B setpoint, any system leakage prior to initiation of Phase B isolation would be into containment. Therefore, the combination of the CCS design and Phase B isolation ensures the CCS is not a potential path for radioactive release from containment.

Phase B containment isolation is actuated by Containment Pressure – High High, or manually, via the automatic actuation logic, as previously discussed. For containment pressure to reach a value high enough to actuate Containment Pressure – High High, a large break LOCA or SLB must have occurred and containment spray must have been actuated. RCP operation will no longer be required and CCS to the RCPs is, therefore, no longer necessary. The RCPs can be operated with seal injection flow alone and without CCS flow to the thermal barrier heat exchanger.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Containment Isolation (continued)

Manual Phase B Containment Isolation is accomplished by the same switches that actuate Containment Spray. When the two switches in either set are turned simultaneously, Phase B Containment Isolation and Containment Spray will be actuated in both trains.

a. Containment Isolation - Phase A Isolation

(1) Phase A Isolation - Manual Initiation

Manual Phase A Containment Isolation is actuated by either of two switches in the control room or from local panel(s). Either switch actuates both trains. Note that manual initiation of Phase A Containment Isolation also actuates Containment Vent Isolation.

(2) Phase A Isolation - Automatic Actuation Logic and Actuation Relays

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of Phase A Containment Isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a Phase A Containment Isolation, actuation is simplified by the use of the manual actuation hand switches.

Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase A Containment Isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Containment Isolation - Phase A Isolation (continued)

(3) Phase A Isolation - Safety Injection

Phase A Containment Isolation is also initiated by all Functions that initiate SI. The Phase A Containment Isolation requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

b. Containment Isolation - Phase B Isolation

Phase B Containment Isolation is accomplished by Manual Initiation, Automatic Actuation Logic and Actuation Relays, and by Containment Pressure channels. The Containment Pressure initiation of Phase B Containment Isolation is energized to actuate in order to minimize the potential of spurious initiations that may damage the RCPs.

(1) Phase B Isolation - Manual Initiation

(2) Phase B Isolation - Automatic Actuation Logic and Actuation Relays

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of Phase B Containment Isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. However, because of the large number of components actuated on a Phase B Containment Isolation, actuation is simplified by the use of the manual actuation hand switches. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase B Containment

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Containment Isolation - Phase B Isolation (continued)

Isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) Phase B Isolation-Containment Pressure - High High

The basis for containment pressure MODE applicability is as discussed for ESFAS Function 2.c above.

4. Steam Line Isolation

Isolation of the main steam lines provides protection in the event of a SLB inside or outside containment.

Rapid isolation of the steam lines will limit the steam break accident to the blowdown from one SG, at most. For a SLB upstream of the main steam isolation valves (MSIVs), inside or outside of containment, closure of the MSIVs limits the accident to the blowdown from only the affected SG. For a SLB downstream of the MSIVs, closure of the MSIVs terminates the accident as soon as the steam lines depressurize. Steam Line Isolation also mitigates the effects of a feed line break and ensures a source of steam for the turbine driven AFW pump during a feed line break.

a. Steam Line Isolation - Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the control room. There are four switches in the control room (one for each valve) which can immediately close each individual MSIV. The LCO requires one switch for each valve to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Steam Line Isolation - Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of steam line isolation must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the RCS and SGs to have a SLB or other accident. This could result in the release of significant quantities of energy and cause a cooldown of the primary system. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs are closed and de-activated. In MODES 4, 5, and 6, there is insufficient energy in the RCS and SGs to experience a SLB or other accident releasing significant quantities of energy.

c. Steam Line Isolation - Containment Pressure - High High

This Function actuates closure of the MSIVs in the event of a LOCA or a SLB inside containment to maintain at least one unfaulted SG as a heatsink for the reactor, and to limit the mass and energy release to containment. The transmitters (d/p cells) are located outside containment, inside the containment annulus, with the sensing line (high pressure side of the transmitter) located inside containment. Containment Pressure - High High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with two-out-of-three logic. However, for enhanced reliability, this Function was designed with four channels and a two-out-of-four logic. The transmitters and electronics are located inside the containment annulus, but outside containment, and experience more adverse environmental conditions than if they were located outside containment altogether. However, the environmental effects are less severe than if the transmitters were located inside containment. The NTSP reflects the inclusion of both steady state instrument uncertainties and slightly more adverse environmental instrument uncertainties.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

c. Steam Line Isolation - Containment Pressure - High High (continued)

Containment Pressure - High High must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The Steam Line Isolation Function remains OPERABLE in MODES 2 and 3 unless all MSIVs are closed and de-activated. In MODES 4, 5, and 6, there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure - High High setpoint.

d. Steam Line Isolation - Steam Line Pressure

(1) Steam Line Pressure - Low

Steam Line Pressure - Low provides closure of the MSIVs in the event of a SLB to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. This Function provides closure of the MSIVs in the event of a feed line break to ensure a supply of steam for the turbine driven AFW pump. Steam Line Pressure - Low was discussed previously under SI Function 1.e.

Steam Line Pressure - Low Function must be OPERABLE in MODES 1, 2, and 3 (above P-11), with any main steam valve open, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11, an inside containment SLB will be terminated by automatic actuation via Containment Pressure - High High. Stuck valve transients and outside containment SLBs will be terminated by the Steam Line Pressure - Negative Rate - High signal for Steam Line Isolation below P-11 when SI has been manually blocked. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs are closed and de-activated. This Function is not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(2) Steam Line Pressure - Negative Rate - High

Steam Line Pressure - Negative Rate - High provides closure of the MSIVs for a SLB when less than the P-11 setpoint, to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. When the operator manually blocks the Steam Line Pressure - Low main steam isolation signal when less than the P-11 setpoint, the Steam Line Pressure - Negative Rate - High signal is automatically enabled. Steam Line Pressure - Negative Rate - High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy requirements with a two-out-of-three logic on each steam line.

Steam Line Pressure - Negative Rate - High must be OPERABLE in MODE 3 when less than the P-11 setpoint, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). In MODES 1 and 2, and in MODE 3, when above the P-11 setpoint, this signal is automatically blocked and the Steam Line Pressure - Low signal is automatically enabled. The Steam Line Isolation Function is required to be OPERABLE in MODES 2 and 3 unless all MSIVs are closed and de-activated. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to have a SLB or other accident that would result in a release of significant enough quantities of energy to cause a cooldown of the RCS.

While the transmitters may experience elevated ambient temperatures due to a SLB, the trip function is based on rate of change, not the absolute accuracy of the indicated steam pressure. Therefore, the NTSP reflects only steady state instrument uncertainties.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. Turbine Trip and Feedwater Isolation

The primary functions of the Turbine Trip and Feedwater Isolation signals are to prevent damage to the turbine due to water in the steam lines, and to stop the excessive flow of feedwater into the SGs. These Functions are necessary to mitigate the effects of a high water level in the SGs, which could result in carryover of water into the steam lines and excessive cooldown of the primary system. The SG high water level is due to excessive feedwater flows.

An additional function of the Turbine Trip and Feedwater Isolation signal is to prevent submergence of safety related equipment in the Main Steam Valve Vault (MSVV) Rooms in the event of a Main Feedwater Line Break.

This Function is actuated by SG Water Level - High High, MSVV Water Level - High, or by an SI signal. The RTS also initiates a turbine trip signal whenever a reactor trip (P-4) is generated. In the event of SI, the unit is taken off line and the turbine generator must be tripped. The MFW System is also taken out of operation, and the AFW System is automatically started.

The SI signal was discussed previously.

a. Turbine Trip and Feedwater Isolation - Actuation Logic and Actuation Relays

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Turbine Trip and Feedwater Isolation – Steam Generator Water Level-High High (P-14)

This signal provides protection against excessive feedwater flow. The ESFAS SG water level instruments provide input to the SG Water Level Control System. Therefore, the actuation logic must be able to withstand both an input failure to the control system (which may then require the protection function actuation) and a single failure in the other channels providing the protection function actuation. Since Watts Bar has only 3 level channels per SG, control/protection interaction is addressed by the use of a Median Signal Selector which prevents a single failure of a

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Turbine Trip and Feedwater Isolation – Steam Generator Water Level-High High (P-14) (continued)

channel providing input to the control system requiring protection function action. That is, a single failure of a channel providing input to the control system does not result in the control system initiating a condition requiring protection function action. The Median Signal Selector performs this by not selecting the channels indicating the highest or lowest steam generator levels as input to the control system.

The Function is actuated when the level in any SG exceeds the high high setpoint, and performs the following functions:

- Trips the main turbine;
- Trips the MFW pumps;
- Initiates feedwater isolation; and
- Shuts the MFW regulating valves and the bypass feedwater regulating valves.

Since no adverse control system action may now result from a single, failed protection instrument channel, a second random protection system failure (as would otherwise be required by Reference 4) need not be considered.

The transmitters (d/p cells) are located inside containment. However, the events that this Function protects against cannot cause a severe environment in containment. Therefore, the NTSP reflects only steady state instrument uncertainties.

c. Turbine Trip and Feedwater Isolation - Safety Injection

Turbine Trip and Feedwater Isolation is also initiated by all Functions that initiate SI. The Feedwater Isolation Function requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 1, SI, is referenced for all initiating functions and requirements.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

d. Turbine Trip and Feedwater Isolation - Main Steam Valve Vault Room Water Level - High

This signal precludes submergence of equipment that is required for safe shutdown in the event of a MSVV Room flood due to a Main Feedwater line break. MSVV Room Water Level - High does not provide any control function. Thus, three OPERABLE channels in each Valve Vault Room are sufficient to satisfy the protection requirements with a two-out-of-three logic.

The level switches which are located inside the MSVV Rooms are subjected to adverse environmental conditions during a Main Feedwater line break. The NTSP reflects both steady state and adverse environmental instrument uncertainties.

Turbine Trip and Feedwater Isolation Functions - Automatic Actuation Logic and Actuation Relays, Steam Generator Water Level - High High (P-14), and Safety Injection must be OPERABLE in MODES 1, 2, and 3 except when all MFIVs, MFRVs, and associated bypass valves are closed and de-activated or isolated by a closed manual valve when the MFW System is in operation and the turbine generator may be in operation. In MODES 4, 5, and 6, the MFW System and the turbine generator are not in service and this Function is not required to be OPERABLE.

Turbine Trip and Feedwater Isolation Function - MSVV Room Water Level - High must be OPERABLE in MODE 1 and in MODE 2 when the Turbine Driven Main Feedwater Pumps are operating. In MODE 2, due to the limited capacity of the Standby Main Feed Pump, and in MODES 3, 4, 5, and 6 a Main Feedwater Line break will not result in flooding which will submerge required safety equipment in the MSVV Rooms, therefore this Function is not required to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The system has two motor driven pumps and a turbine driven pump, making it available during normal unit operation, during a loss of AC power, a loss of MFW, and during a Feedwater System pipe break. The normal source of water for the AFW System is the condensate storage tank (CST) (non safety related). A low suction pressure to the AFW pumps will automatically realign the pump suctions to the Essential Raw Cooling Water (ERCW) System (safety related). The AFW System is aligned so that upon a pump start, flow is initiated to the respective SGs immediately.

a. Auxiliary Feedwater - Automatic Actuation Logic and Actuation Relays (Solid State Protection System)

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Auxiliary Feedwater - Steam Generator Water Level – Low Low

SG Water Level – Low Low provides protection against a loss of heat sink due to a feed line break outside of containment, or a loss of MFW, which results in a loss of SG water level. SG Water Level – Low Low provides input to the SG Level Control System as well as Automatic Actuation of AFW. Since Watts Bar has only 3 channels per SG, control protection interaction is addressed by the use of a Median Signal Selector as discussed in the bases for Function 5.b, "Steam Generator Water Level - High High."

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions (feed line break), the SG Water Level – Low Low NTSP may not have sufficient margin to account for adverse environmental instrument uncertainties. In this case, AFW pump start will be provided by a Containment Pressure - High SI signal.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Auxiliary Feedwater - Steam Generator Water Level – Low Low (continued)

The Steam Generator Water Level Channel Trip Time Delay (TTD) creates additional operational margin when the unit needs it most, during power escalation from low power, by allowing the operator time to recover level when the primary side load is sufficiently small to allow such action. The TTD is based on continuous monitoring of primary side power through the use of vessel ΔT. Two time delays are calculated, based on the number of steam generators indicating less than the Low Low Level channel NTSP per Note 1 of Table 3.3.2-1. The magnitude of the delays decreases with increasing primary side power level, up to 50% RTP. Above 50% RTP there are no time delays for the Low Low Level channel trips.

The algorithm for the TTD, T_s and T_m, determines the trip delay as a function of power level (P) and four constants (A through D for T_s, E through H for T_m). An allowance for the accuracy of the Eagle-21™ time base is included in the determination of the magnitude of the constants. The magnitude of the accuracy allowance is 1%, i.e., the constant values were multiplied by 0.99 to account for this potential error.

In the event of a failure of a Steam Generator Water Level channel, the channel is placed in the trip condition as input to the Solid State Protection System and does not affect the TTD setpoint calculations for the remaining OPERABLE channels. It is then necessary for the operator to force the use of the shorter TTD time delay by adjustment of the single steam generator time delay calculation (T_S) to match the multiple steam generator time delay calculation (T_M) for the affected protection set, through the Man Machine Interface. Failure of the vessel ΔT channel input (failure of more than one T_H RTD or failure of both T_C RTDs) affects the TTD calculation for a protection set. This results in the requirement that the operator adjust the threshold power level for zero seconds time delay from 50% RTP to 0% RTP, through the Man Machine Interface.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Auxiliary Feedwater - Steam Generator Water Level – Low Low (continued)

Refer to the Bases for the Steam Generator Water Level Low-Low Reactor Trip, B 3.3.1, for a discussion of the required MODES and normalization of the vessel ΔT input to the TTD.

c. Auxiliary Feedwater - Safety Injection

An SI signal starts the motor driven and turbine driven AFW pumps. The AFW initiation functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

d. Auxiliary Feedwater - Loss of Offsite Power

A loss of offsite power to the RCP buses will be accompanied by a loss of reactor coolant pumping power and the subsequent need for some method of decay heat removal. The loss of offsite power is detected by a voltage drop on each 6.9 kV shutdown board. Loss of power to either 6.9 kV shutdown board will start the turbine driven AFW pump to ensure that enough water is available to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip.

Functions 6.a through 6.d (except the loop ΔT input to the trip time delay) must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. SG Water Level - Low Low in any operating SG will cause the motor driven AFW pumps to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. SG Water Level - Low Low in any two operating SGs will cause the turbine driven pump to start. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

e. Auxiliary Feedwater - Trip Of All Main Turbine Driven Feedwater Pumps

A Trip of both turbine driven MFW pumps is an indication of a loss of MFW and the subsequent need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure. A turbine driven MFW pump is equipped with one pressure switch on the control oil line for the speed control system. A low pressure signal from this pressure switch indicates a trip of that pump. A trip of both turbine driven MFW pumps starts the motor driven and turbine driven AFW pumps to ensure that enough water is available to act as the heat sink for the reactor.

This Function must be OPERABLE in MODES 1 and 2. This ensures that at least one SG is provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of an accident. MODE 2 applicability is when one or more turbine driven MFW pump(s) are supplying feedwater to the steam generators. In MODE 2 the AFW system pump(s) will be used for startup/shutdown conditions. During startup, a turbine driven MFW pump is placed in service along with the operating AFW System pump(s). During the process of placing the first turbine driven MFW pump in service, the anticipatory AFW auto-start channel for the non-operating turbine driven MFW pump is placed in “bypass” (electrical control circuit is de-energized) to prevent inadvertent AFW auto-start during rollup trip testing and overspeed trip testing. Once the operating turbine driven MFW pump has established sufficient feed flow to maintain SG level, the anticipatory AFW auto-start channel for the non-operating turbine driven MFW pump is placed in the “trip” condition, and the AFW pumps secured. Under these conditions, the AFW auto start circuit will be in a half trip condition (one-out-of-two) in MODE 2 and during transitions from MODE 2 to MODE 1. If the operating turbine driven MFW pump were to trip during this time period, an AFW auto start signal would be generated causing all three AFW pumps to start. Having the requirement for auto start of the AFW pumps to be required only when one or more turbine driven MFW pumps are in service limits the potential for an overcooling transient due to inadvertent AFW actuation. MODE 1 applicability allows entry into LCO 3.3.2, Condition J to be suspended for up to 4 hours when placing the second turbine driven MFW pump in service or removing one of two turbine driven MFW pumps from service.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

e. Auxiliary Feedwater - Trip Of All Main Turbine Driven Feedwater Pumps (continued)

This provision will reduce administrative burden on the plant. Plant safety is not compromised during this short period because the safety grade AFW auto start channels associated with steam generator low-low levels are operable. In MODES 3, 4, and 5, the RCPs and MFW pumps may be normally shut down, and thus neither pump trip is indicative of a condition requiring automatic AFW initiation.

f. Auxiliary Feedwater - Pump Suction Transfer on Suction Pressure - Low

A low pressure signal in the AFW pump suction line protects the AFW pumps against a loss of the normal supply of water for the pumps, the CST. Three pressure switches are located on each motor driven AFW pump suction line from the CST. A low pressure signal sensed by two switches of a set will cause the emergency supply of water for the respective pumps to be aligned. ERCW (safety grade) is then lined up to supply the AFW pumps to ensure an adequate supply of water for the AFW System to maintain at least one of the SGs as the heat sink for reactor decay heat and sensible heat removal.

Since the detectors are located in an area not affected by HELBs or high radiation, they will not experience any adverse environmental conditions and the NTSP reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, 3, and 4, when the steam generators are relied on to remove decay heat from the reactor, to ensure a safety grade supply of water for the AFW System to maintain the SGs as the heat sink for the reactor. This Function does not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink.

In MODE 4, AFW automatic suction transfer does not need to be OPERABLE once RHR is in operation.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Automatic Switchover to Containment Sump

At the end of the injection phase of a LOCA, the RWST will be nearly empty. Continued cooling must be provided by the ECCS to remove decay heat. The source of water for the ECCS pumps is automatically switched to the containment recirculation sump. The low head residual heat removal (RHR) pumps draw the water from the containment recirculation sump, the RHR pumps pump the water through the RHR heat exchanger, inject the water back into the RCS, and supply the cooled water to the other ECCS pumps.

Switchover from the RWST to the containment sump must occur before the RWST empties to prevent damage to the RHR pumps and a loss of core cooling capability. For similar reasons, switchover must not occur before there is sufficient water in the containment sump to support ESF pump suction. Furthermore, early switchover must not occur to ensure that sufficient borated water is injected from the RWST. This ensures the reactor remains shut down in the recirculation mode.

a. Automatic Switchover to Containment Sump - Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Automatic Switchover to Containment Sump - Refueling Water Storage Tank (RWST) Level - Low Coincident With Safety Injection and Coincident With Containment Sump Level – High

During the injection phase of a LOCA, the RWST is the source of water for all ECCS pumps. A low level in the RWST coincident with an SI signal provides protection against a loss of water for the ECCS pumps and indicates the end of the injection phase of the LOCA. The RWST is equipped with four level transmitters. These transmitters provide no control functions. Therefore, a two-out-of-four logic is adequate to initiate the protection function actuation. Although only three channels would be sufficient, a fourth channel has been added for increased reliability.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Automatic Switchover to Containment Sump - Refueling Water Storage Tank (RWST) Level - Low Coincident With Safety Injection and Coincident With Containment Sump Level – High (continued)

The RWST – Low NTSP is selected to ensure switchover occurs before the RWST empties, to prevent ECCS pump damage.

This setpoint will also ensure that enough borated water is injected to maintain the reactor shut down. The limit also ensures adequate water inventory in the containment sump to provide ECCS pump suction.

The transmitters are located in an area not affected by HELBs or post accident high radiation. Thus, they will not experience any adverse environmental conditions and the NTSP reflects only steady state instrument uncertainties.

Automatic switchover occurs only if the RWST low level signal is coincident with SI. This prevents accidental switchover during normal operation. Accidental switchover could damage ECCS pumps if they are attempting to take suction from an empty sump. The automatic switchover Function requirements for the SI Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

Additional protection from spurious switchover is provided by requiring a Containment Sump Level - High signal as well as RWST Level - Low and SI. This ensures sufficient water is available in containment to support the recirculation phase of the accident. A Containment Sump Level - High signal must be present, in addition to the SI signal and the RWST Level - Low signal, to transfer the suctions of the RHR pumps to the containment sump. The containment sump is equipped with four level transmitters. These transmitters provide no control functions. Therefore, a two-out-of-four logic is adequate to initiate the protection function actuation. Although only three channels would be sufficient, a fourth channel has been added for increased reliability. The containment sump level NTSP is selected to ensure enough borated water is injected to ensure the reactor remains shut down. The high limit also

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Automatic Switchover to Containment Sump - Refueling Water Storage Tank (RWST) Level - Low Coincident With Safety Injection and Coincident With Containment Sump Level – High (continued)

ensures adequate water inventory in the containment sump to provide ECCS pump suction. The transmitters are located inside containment and thus possibly experience adverse environmental conditions. Therefore, the NTSP reflects the inclusion of both steady state and environmental instrument uncertainties.

These Functions must be OPERABLE in MODES 1, 2, 3, and 4 when there is a potential for a LOCA to occur, to ensure a continued supply of water for the ECCS pumps. These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. System pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

8. Engineered Safety Feature Actuation System Interlocks

To allow some flexibility in unit operations, several interlocks are included as part of the ESFAS. These interlocks permit the operator to block some signals, automatically enable other signals, prevent some actions from occurring, and cause other actions to occur. The interlock Functions back up manual actions to ensure bypassable functions are in operation under the conditions assumed in the safety analyses.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

8. Engineered Safety Feature Actuation System Interlocks (continued)

a. Engineered Safety Feature Actuation System Interlocks - Reactor Trip, P-4

The P-4 interlock is enabled when a reactor trip breaker (RTB) and its associated bypass breaker is open. Once the P-4 interlock is enabled, automatic SI initiation may be blocked after a 90 second time delay. This Function allows operators to take manual control of SI systems after the initial phase of injection is complete. Once SI is blocked, automatic actuation of SI cannot occur until the RTBs have been manually closed. The functions of the P-4 interlock are:

- Trip the main turbine;
- Isolate MFW with coincident low T_{avg};
- Prevent reactuation of SI after a manual reset of SI;
- Transfer the steam dump from the load rejection controller to the unit trip controller; and
- Prevent opening of the MFW isolation valves if they were closed on SI or SG Water Level - High High, or MSVV Water Level - High.

Each of the above Functions is interlocked with P-4 to avert or reduce the continued cooldown of the RCS following a reactor trip. An excessive cooldown of the RCS following a reactor trip could cause an insertion of positive reactivity with a subsequent increase in generated power.

To avoid such a situation, the noted Functions have been interlocked with P-4 as part of the design of the unit control and protection system.

None of the noted Functions serves a mitigation function in the unit licensing basis safety analyses. Only the turbine trip Function is explicitly assumed since it is an immediate consequence of the reactor trip Function. Neither turbine trip, nor any of the other four Functions associated with the reactor trip signal, is required to show that the unit licensing basis safety analysis acceptance criteria are not exceeded.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Engineered Safety Feature Actuation System Interlocks - Reactor Trip, P-4 (continued)

The RTB position switches that provide input to the P-4 interlock only function to energize or de-energize or open or close contacts. Therefore, this Function has no adjustable trip setpoint with which to associate a NTSP and Allowable Value.

This Function must be OPERABLE in MODES 1, 2, and 3 when the reactor may be critical or approaching criticality. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because the main turbine, the MFW System, and the Steam Dump System are not in operation.

b. Engineered Safety Feature Actuation System Interlocks - Pressurizer Pressure, P-11

The P-11 interlock permits a normal unit cooldown and depressurization without actuation of SI or main steam line isolation. With two-out-of-three pressurizer pressure channels (discussed previously) less than the P-11 setpoint, the operator can manually block the Pressurizer Pressure - Low and Steam Line Pressure - Low SI signals and the Steam Line Pressure - Low steam line isolation signal (previously discussed). When the Steam Line Pressure - Low SI and Steam Line Isolation signals are manually blocked, the Steam Line Pressure Negative Rate - High is automatically enabled. With two out of three pressurizer pressure channels ≥ P-11 setpoint, the Pressurizer Pressure - Low and Steam Line Pressure - Low SI Steam Line Isolation signals are automatically enabled, and Steam Line Pressure Negative Rate - High is automatically blocked. The NTSP reflects only steady state instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the unit without the actuation of SI or main steam isolation. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because system pressure must already be below the P-11 setpoint for the requirements of the heatup and cooldown curves to be met.

The ESFAS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.2-1.

In the event a channel's NTSP is found nonconservative with respect to the Allowable Value, or the channel is not functioning as required, or the transmitter, instrument loop, signal processing electronics, setpoint comparator output, contact output, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified (e.g., on a per steam line, per loop, per SG, etc., basis), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

When the number of inoperable channels in a trip function exceed those specified in one or other related Conditions associated with a trip function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all ESFAS protection functions.

Condition A addresses the situation where one or more channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1, B.2.1 and B.2.2

Condition B applies to manual initiation of:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B Isolation.

Condition B also applies to the Auxiliary Feedwater Pump Suction Transfer on Suction Pressure - Low.

For the manual initiation Functions, this action addresses the train orientation of the SSPS for the functions listed above. For the AFW System pump suction transfer channels, this action recognizes that

(continued)

BASES

ACTIONS (continued)

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

placing a failed channel in trip during operation is not necessarily a conservative action. Spurious trip of this function could align the AFW System to a source that is not immediately capable of supporting pump suction. If a channel or train is inoperable, 48 hours is allowed to return it to an OPERABLE status. Note that for containment spray and Phase B isolation, failure of one or both channels in one train renders the train inoperable. Condition B, therefore, encompasses both situations.

For the manual initiation Functions, the specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each Function, and the low probability of an event occurring during this interval. For the AFW System pump suction transfer channels, the specified Completion Time is reasonable considering the nature of this Function, the available redundancy, and the low probability of an event occurring during this interval. If the channel or train cannot be restored to OPERABLE status, 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 an additional 6 hours (54 hours total time) and in MODE 5 within an additional 30 hours (84 hours total time). The allowable 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. For the AFW System pump suction transfer channels, aligning the RHR System for decay heat removal, so that the steam generators are not relied on for heat removal, places the plant in a MODE in which the LCO no longer applies. Therefore, per LCO 3.0.2, completion of the Required Action to place the unit in MODE 5 is not required.

For the manual initiation Functions, the allowance of 48 hours is justified in Reference 7.

(continued)

BASES

ACTIONS (continued)

C.1, C.2.1 and C.2.2

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

SI;

Containment Spray;

Phase A Isolation;

Phase B Isolation; and

Automatic Switchover to Containment Sump.

This action addresses the train orientation of the SSPS and the master and slave relays. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the inoperable train to OPERABLE status are justified in Reference 17. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, 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 an additional 6 hours (30 hours total time) and in MODE 5 within an additional 30 hours (60 hours total time). The Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing, provided the other train is OPERABLE. This allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Ref. 7) that 4 hours is the average time required to perform train surveillance.

(continued)

BASES

ACTIONS (continued)

D.1, D.2.1, and D.2.2

Condition D applies to:

- Containment Pressure - High;
- Pressurizer Pressure - Low;
- Steam Line Pressure - Low; and
- Steam Line Pressure - Negative Rate - High.

If one channel is inoperable, 72 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic. Therefore, failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-three configuration that satisfies redundancy requirements. The 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition are justified in Reference 17.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the plant be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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. In MODE 4, these functions are no longer required OPERABLE.

The Required Actions have been modified by a Note that allows placing an inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of other channels. The Note also allows a channel to be placed in bypass for up to 12 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 12 hours allowed for testing are justified in Reference 17.

(continued)

BASES

ACTIONS (continued)

E.1, E.2.1, and E.2.2

Condition E applies to:

- Containment Spray Containment Pressure - High High;
- Steam Line Isolation - Containment Pressure - High High; and
- Containment Phase B Isolation - Containment Pressure - High High.

None of these signals has input to a control function. Thus, two-out-of-three logic is necessary to meet acceptable protective requirements. However, a two-out-of-three design would require tripping a failed channel. This is undesirable because a single failure would then cause spurious containment spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented. Therefore, these channels are designed with two-out-of-four logic so that a failed channel may be bypassed rather than tripped. Note that one channel may be bypassed and still satisfy the single failure criterion. Furthermore, with one channel bypassed, a single instrumentation channel failure will not spuriously initiate containment spray.

To avoid the inadvertent actuation of containment spray and Phase B containment isolation, the inoperable channel should not be placed in the tripped condition. Instead it is bypassed. Restoring the channel to OPERABLE status, or placing the inoperable channel in the bypass condition within 72 hours, is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The Completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable channel to OPERABLE status, or place it in the bypassed condition within 72 hours, requires the plant be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 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. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The channel to be tested can be tested in bypass with the inoperable channel also in bypass. The time limit is justified in Reference 17.

(continued)

BASES

ACTIONS (continued)

F.1, F.2.1, and F.2.2

Condition F applies to:

- Manual Initiation of Steam Line Isolation;
- Loss of Offsite Power; and
- P-4 Interlock.

For the Manual Initiation and the P-4 Interlock Functions, this action addresses the train orientation of the SSPS. For the Loss of Offsite Power Function, this action recognizes the lack of manual trip provision for a failed channel. If a train or channel is inoperable, 48 hours is allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of these Functions, the available redundancy, and the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the plant must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power in an orderly manner and without challenging plant systems. In MODE 4, the plant does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

(continued)

BASES

ACTIONS (continued)

G.1, G.2.1 and G.2.2

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation and AFW actuation Functions.

The action addresses the train orientation of the SSPS and the master and slave relays for these functions. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status. The 24 hours allowed for restoring the channel to OPERABLE status or to place it in the tripped condition are justified in Reference 17. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the plant must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 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. Placing the plant in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the plant does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 4 hours is the average time required to perform channel surveillance.

(continued)

BASES

ACTIONS (continued)

H.1, H.2.1 and H.2.2

Condition H applies to the automatic actuation logic and actuation relays for the Turbine Trip and Feedwater Isolation Function.

This action addresses the train orientation of the SSPS and the master and slave relays for this Function. If one train is inoperable, 24 hours are allowed to restore the train to OPERABLE status or the plant must be placed in MODE 3 within 6 hours and in MODE 4 in the following 6 hours. The 24 hours allowed for restoring the channel to OPERABLE status or to place it in the tripped condition are justified in Reference 17. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. The allowed Completion Times are reasonable, based on operating experience, to reach MODE 4 from full power conditions in an orderly manner and without challenging plant systems. These Functions are no longer required in MODE 4. Placing the plant in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the plant does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 4 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 4 hours is the average time required to perform channel surveillance.

I.1, I.2.1 and I.2.2

Condition I applies to SG Water Level - High High (P-14).

If one channel is inoperable, 72 hours are allowed to restore one channel to OPERABLE status or to place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-two logic will result in actuation. The 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition are justified in Reference 17. Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the plant to be placed in MODE 3 in 6 hours and in MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach MODE 4 from full power conditions in an orderly manner and without challenging plant systems. In MODE 4, these Functions are no longer required OPERABLE.

(continued)

BASES

ACTIONS (continued)

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

The Required Actions have been modified by a Note that allows placing an inoperable channel in bypassed condition for up to 12 hours while performing routine surveillance testing of other channels. The Note also allows a channel to be placed in bypass for up to 12 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 12 hours allowed for testing are justified by Reference 17.

J.1 and J.2

Condition J applies to the AFW pump start on trip of all turbine driven MFW pumps.

The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. If a channel is inoperable, 48 hours are allowed to return it to an OPERABLE status. If the function cannot be returned to an OPERABLE status, 6 hours are allowed to place the plant in MODE 3. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. In MODE 3, the plant does not have any analyzed transients or conditions that require the explicit use of the protection function noted above. The allowance of 48 hours to return the train to an OPERABLE status is justified in Reference 7.

MODE 1 applicability allows entry into LCO 3.3.2, Condition J to be suspended for up to 4 hours when placing the second turbine driven MFW pump in service or removing one of the two turbine driven MFW pumps from service.

K.1, K.2.1 and K.2.2

Condition K applies to RWST Level - Low Coincident with Safety Injection and Coincident with Containment Sump Level - High.

RWST Level - Low Coincident With SI and Coincident With Containment Sump Level - High provides actuation of switchover to the containment sump. Note that this Function requires the comparators to energize to perform their required action. The failure of up to two channels will not prevent the operation of this Function.

(continued)

BASES

ACTIONS (continued)

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

However, placing a failed channel in the tripped condition could result in a premature switchover to the sump, prior to the injection of the minimum volume from the RWST. Placing the inoperable channel in bypass results in a two-out-of-three logic configuration, which satisfies the requirement to allow another failure without disabling actuation of the switchover when required.

Restoring the channel to OPERABLE status or placing the inoperable channel in the bypass condition within 72 hours is sufficient to ensure that the Function remains OPERABLE, and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The 72 hour Completion Time is justified in References 10, 17, and 19. If the channel cannot be returned to OPERABLE status or placed in the bypass condition within 72 hours, the plant must be brought to MODE 3 within the following 6 hours and MODE 5 within the next 30 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. In MODE 5, the plant does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows placing one channel in bypass for up to 12 hours while performing routine surveillance testing. The channel to be tested can be tested in bypass with the inoperable channel also in bypass. The time limit is justified in Reference 17.

L.1, L.2.1 and L.2.2

Condition L applies to the P-11 Interlock.

With one channel inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing plant condition, the plant must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours.

(continued)

BASES

ACTIONS (continued)

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

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. Placing the plant in MODE 4 removes all requirements for OPERABILITY of these interlocks.

M.1.1, M.1.2 and M.2

Condition M is applicable to the SG Water Level Low-Low Function.

A known channel inoperable, must be restored to OPERABLE status, or placed in the tripped condition within 72 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trip. The 72 hours allowed to restore the channel to OPERABLE status or to place it in the tripped condition are justified in Reference 17.

If a channel fails, it is placed in the tripped condition and does not affect the TTD setpoint calculations for the remaining OPERABLE channels. It is then necessary for the operator to force the use of the shorter TTD Time Delay by adjustment of the single SG time delay calculation (T_S) to match the multiple SG time delay calculation (T_M) for the affected protection set, through the Man-Machine Interface.

If the inoperable channel cannot be restored or placed in the tripped condition within the specified Completion Time, the plant must be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours. The allowed Completion Times are reasonable, based on operating experience, to place the plant in MODE 3 from MODE 1 full power conditions in an orderly manner and without challenging plant systems.

The Required Actions have been modified by a Note that allows placing an inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of other channels. The Note also allows a channel to be placed in bypass for up to 12 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 12 hour time limit is justified in Reference 17.

(continued)

BASES

ACTIONS (continued)

N.1 and N.2

Condition N applies to Vessel ΔT equivalent to Power Function.

Failure of the vessel ΔT channel input (failure of more than one T_H RTD or failure of both T_C RTDs) will affect the TTD calculation for a protection set. This results in the requirement that the operator adjust the threshold power level for zero seconds time delay from 50% RTP to 0% RTP, through the Man-Machine Interface. If the inoperable channel cannot be restored or the threshold power level for zero seconds time delay adjusted within the specified Completion Time, the plant must be placed in a MODE where this Function is not required to be OPERABLE. An additional 6 hours is allowed to place the plant in MODE 3. Six hours is a reasonable time based on operating experience, to place the plant in MODE 3 from MODE 1 full power conditions in an orderly manner and without challenging plant systems.

The Required Actions have been modified by a Note that allows placing an inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The Note also allows a channel to be placed in bypass for up to 12 hours for testing of the bypassed channel. However, only one channel may be placed in bypass at any one time. The 12 hour time limit is justified in Reference 17.

O.1 and O.2

Condition O applies to the North or South MSVV Room Water Level – High function.

If one channel is inoperable, 72 hours are allowed to restore that channel to OPERABLE status or place it in the tripped condition. If placed in the tripped condition, the Function is then in a partial trip condition where one-out-of-two logic will result in actuation. The 72 hours allowed to place the inoperable channel in the tripped condition are justified in References 10 and 17.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 72 hours requires the plant to be placed in MODE 3 within the following 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. In MODE 3, these functions are no longer required OPERABLE.

(continued)

BASES (continued)

ACTIONS (actions)

O.1 and O.2 (continued)

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 12 hours while performing routine surveillance testing of the other channels. The 12 hour time limit is justified in References 10 and 17.

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the Surveillance Requirements column of Table 3.3.2-1.

A Note has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

Note that each channel of process protection supplies both trains of the ESFAS. When testing channel I, train A and train B must be examined. Similarly, train A and train B must be examined when testing channel II, channel III, and channel IV. The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

The protection Functions associated with the EAGLE-21™ Process Protection System have an installed bypass capability, and may be tested in either the trip or bypass mode, as approved in Reference 7. When testing is performed in the bypass mode, the SSPS input relays are not operated, as justified in Reference 10. The input relays are checked during the CHANNEL CALIBRATION every 18 months.

SR 3.3.2.1

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1 (continued)

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and reliability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

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

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The SSPS is tested every 92 days on a STAGGERED TEST BASIS, using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and that there is an intact voltage signal path to the master relay coils. The Frequency of every 92 days on a STAGGERED TEST BASIS is justified in Reference 18.

SR 3.3.2.3

SR 3.3.2.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is injected to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. This test is performed every 92 days on a STAGGERED TEST BASIS. The Frequency of 92 days is justified in Reference 18.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found conservative with respect to the Allowable Values specified in Table 3.3.2-1.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.4 (continued)

The difference between the current "as found" values and the NTSP or previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the setpoint methodology.

The Frequency of 184 days is justified in Reference 18, except for Function 7. The Frequency for Function 7 is justified in References 10 and 18.

R 3.3.2.4 is modified by two Notes as identified in Table 3.3.2-1. The first Note requires evaluation of channel performance for the condition where the as found setting for the channel setpoint is outside its as found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as left setting for the channel be returned to within the as left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as left and as found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as left channel setting cannot be returned to a setting within the as left tolerance of the NTSP, then the channel shall be declared inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.5

SR 3.3.2.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function, or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation MODE is prevented from operation by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay. This test is performed every 92 days. The Frequency is adequate, based on industry operating experience, considering instrument reliability and operating history data.

For ESFAS slave relays which are Westinghouse type AR or Potter & Brumfield MDR series relays, the SLAVE RELAY TEST is performed every 18 months. The frequency is based on the relay reliability assessments presented in References 13 and 22. These reliability assessments are relay specific and apply only to Westinghouse type AR and Potter & Brumfield MDR series relays with AC coils. Note that, for normally energized applications, the relays may require periodic replacement in accordance with the guidance given in References 13 and 22.

This SR is modified by a Note, which states that performance of this test is not required for those relays tested by SR 3.3.2.7.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a TADOT every 92 days. This test is a check of the Turbine Trip and Feedwater Isolation - Main Steam Valve Vault Rooms Water Level - High (Functions 5.d and 5.e), and AFW Pump Suction Transfer on Suction Pressure - Low (Function 6.f).

The SR is modified by a Note that excludes verification of setpoints for relays. Relay setpoints require elaborate bench calibration and are verified during CHANNEL CALIBRATION. The Frequency is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.7

SR 3.3.2.7 is the performance of a SLAVE RELAY TEST for slave relays K603A, K603B, K604A, K604B, K607A, K607B, K609A, K609B, K612A, K625A, and K625B. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment which may be operated in the design mitigation MODE is either allowed to function or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment which may not be operated in the design mitigation MODE is prevented from operation by the slave relay test circuit.

For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay. This test is performed every 18 months. The Frequency is justified by TVA correspondence to the NRC dated November 9, 1984 (Ref. 9) and Design Change Notice W-38238-A associated documentation (Ref. 12), and for relays K607A, K607B, and K612A, Westinghouse letter to TVA (Ref. 11).

SR 3.3.2.8

SR 3.3.2.8 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and AFW pump start on trip of all MFW pumps. It is performed every 18 months. The Frequency is based on industry operating experience and is consistent with the typical refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation functions. The manual initiation functions have no associated setpoints.

SR 3.3.2.8 is modified by two Notes as identified in Table 3.3.2-1. The first Note requires evaluation of channel performance for the condition where the as found setting for the channel setpoint is outside its as found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.8 (continued)

The second Note requires that the as left setting for the channel be returned to within the as left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as left and as found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as left channel setting cannot be returned to a setting within the as left tolerance of the NTSP, then the channel shall be declared inoperable.

SR 3.3.2.9

SR 3.3.2.9 is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the Watts Bar setpoint methodology. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

The Frequency of 18 months is based on the assumption of an 18 month calibration interval in the determination of the magnitude of sensor/transmitter drift in the setpoint methodology.

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable. For channels with a trip time delay (TTD), this test shall include verification that the TTD coefficients are adjusted correctly.

SR 3.3.2.9 is modified by two Notes as identified in Table 3.3.2-1. The first Note requires evaluation of channel performance for the condition where the as found setting for the channel setpoint is outside its as found tolerance but conservative with respect to the Allowable Value. Evaluation of channel performance will verify that the channel will continue to behave in accordance with safety analysis assumptions and the channel performance assumptions in the setpoint methodology. The purpose of the assessment is to ensure confidence in the channel performance prior to returning the channel to service. For channels

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.9 (continued)

determined to be OPERABLE but degraded, after returning the channel to service the performance of these channels will be evaluated under the plant Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition. The second Note requires that the as left setting for the channel be returned to within the as left tolerance of the NTSP. Where a setpoint more conservative than the NTSP is used in the plant surveillance procedures (field setting), the as left and as found tolerances, as applicable, will be applied to the surveillance procedure setpoint. This will ensure that sufficient margin to the Safety Limit and/or Analytical Limit is maintained. If the as left channel setting cannot be returned to a setting within the as left tolerance of the NTSP, then the channel shall be declared inoperable.

SR 3.3.2.10

This SR ensures the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the accident analysis. Response Time testing acceptance criteria are included in Technical Requirements Manual, Section 3.3.2 (Ref. 8). Individual component response times are not modeled in the analyses. The analyses model the overall or total elapsed time, from the point at which the parameter exceeds the NTSP value at the sensor, to the point at which the equipment in both trains reaches the required functional state (e.g., pumps at rated discharge pressure, valves in full open or closed position).

For channels that include dynamic transfer functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer functions set to one with the resulting measured response time compared to the appropriate FSAR response time. Alternately, the response time test can be performed with the time constants set to their nominal value provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of sequential tests such that the entire response time is measured.

Response time may be verified by actual response time tests in any series of sequential, overlapping or total channel measurements, or by the summation of allocated sensor, signal processing and actuation logic response times with actual response time tests on the remainder of the channel. Allocations for sensor response times may be obtained from: (1) historical records based on acceptable response time tests (hydraulic, noise, or power interrupt tests), (2) in place, onsite, or offsite

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.10 (continued)

(e.g., vendor) test measurements, or (3) utilizing vendor engineering specifications. WCAP-13632-P-A Revision 2, "Elimination of Pressure Sensor Response Time Testing Requirements" (Ref. 15), provides the basis and methodology for using allocated sensor response times in the overall verification of the channel response time for specific sensors identified in the WCAP. Response time verification for other sensor types must be demonstrated by test.

WCAP-14036-P-A, Revision 1, "Elimination of Periodic Protection Channel Response Time Tests" (Ref. 16), provides the basis and methodology for using allocated signal processing and actuation logic response times in the overall verification of the protection system channel response time. The allocations for sensor, signal conditioning and actuation logic response times must be verified prior to placing the component in operational service and re-verified following maintenance that may adversely affect response time. In general, electrical repair work does not impact response time provided the parts used for repair are of the same type and value. Specific components identified in the WCAP may be replaced without verification testing. One example where response time could be affected is replacing the sensing assembly of a transmitter.

ESF RESPONSE TIME tests are conducted on an 18 month STAGGERED TEST BASIS. Testing of the final actuation devices, which make up the bulk of the response time, is included in the testing of each channel. The final actuation device in one train is tested with each channel.

Therefore, staggered testing results in response time verification of these devices every 18 months. The 18 month Frequency is consistent with the typical refueling cycle and is based on unit operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions are established. This deferral is required because there may be insufficient steam pressure to perform the test.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.11

SR 3.3.2.11 is the performance of a TADOT as described in SR 3.3.2.8, except that it is performed for the P-4 Reactor Trip Interlock, and the Frequency is once per RTB cycle. This Frequency is based on operating experience demonstrating that undetected failure of the P-4 interlock sometimes occurs when the RTB is cycled.

The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Function tested has no associated setpoint.

REFERENCES

1. Watts Bar FSAR, Section 6.0, "Engineered Safety Features."
2. Watts Bar FSAR, Section 7.0, "Instrumentation and Controls."
3. Watts Bar FSAR, Section 15.0, "Accident Analyses."
4. Institute of Electrical and Electronic Engineers, IEEE-279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations," April 5, 1972.
5. Code of Federal Regulations, Title 10, Part 50.49, "Environmental Qualification of Electrical Equipment Important to Safety for Nuclear Power Plants."
6. Regulatory Guide 1.105, "Setpoints for Safety Related Instrumentation," Revision 3.
7. WCAP-10271-P-A, Supplement 1 and Supplement 2, Rev. 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System." May 1986 and June 1990.
8. Watts Bar Technical Requirements Manual, Section 3.3.2, "Engineered Safety Feature Response Times."
9. TVA Letter to NRC, November 9, 1984, "Request for Exemption of Quarterly Slave Relay Testing, (L44 841109 808)."

(continued)

BASES

REFERENCES (continued)

10. Evaluation of the applicability of WCAP-10271-P-A, Supplement 1, and Supplement 2, Revision 1, to Watts Bar, Westinghouse letter to TVA WAT-D-10128.

11. Westinghouse letter to TVA (WAT-D-8347), September 25, 1990, "Charging/Letdown Isolation Transients" (T33 911231 810).

12. Unit 1 Design Change Notice W-38238 and Unit 2 Engineering Document Construction Release 53352 and associated documentation.

13. WCAP-13877-P-A, Revision 2, “Reliability Assessment of Westinghouse Type AR Relays Used As SSPS Slave Relays.”

14. Not Applicable for Unit 2

15. WCAP-13632-P-A Revision 2, “Elimination of Pressure Sensor Response Time Testing Requirements,” January 1996.

16. WCAP-14036-P-A, Revision 1, “Elimination of Periodic Protection Channel Response Time Tests,” October 1998.

17. WCAP-14333-P-A, Revision 1, “Probablistic Risk Analysis of the RPS and ESFAS Test Times and Completion Times,” October 1998

18. WCAP-15376-P-A, Revision 1, “Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times,” March 2003

19. Westinghouse letter to TVA, WAT-D-11248, “Revised Justification for Applicability of Instrumentation Technical Specification Improvements to the Automatic Switchover to Containment Sump Signal,” June 2004.

20. Letter from John G. Lamb (NRC) to Mr. Preston D. Swafford (TVA) dated March 4, 2009, Includes Enclosures (a) Amendment No. 75 to Facility Operating License No. NPF-90 for Watts Bar Nuclear Plant, Unit 1 and (b) NRC Safety Evaluation (SE) for Amendment No. 75.

21. Deleted

22. WCAP-13878-P-A, Revision 2, “Reliability Assessment of Potter & Brumfield MDR Series Relays.”

B 3.3 INSTRUMENTATION

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display unit variables that provide information required by the control room operators during accident situations.

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident.

The availability of accident monitoring instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. These essential instruments are identified by unit specific documents (Ref. 1) addressing the recommendations of Regulatory Guide 1.97 (Ref. 2) as required by Supplement 1 to NUREG-0737 (Ref. 3).

The instrument channels required to be OPERABLE by this LCO include two classifications of parameters (variable Type and Category) identified during unit specific implementation of Regulatory Guide 1.97. These instrument channels are Types A, B, C, D, and E Category 1 variables.

Type A variables are included in this LCO because they provide the primary information required for the control room operator to identify events and take specific manually-controlled actions required by the emergency instructions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Accidents (DBAs). Those Type A variables listed in Table 3.3.3-1 are Category 1 variables.

Types B, C, D, and E (non-Type A) Category 1 variables are the key variables deemed risk significant because they are needed to:

- Type B - Determine whether other systems important to safety are performing their intended functions;
- Type C - Provide information to the operators that will enable them to determine the likelihood of a gross breach of the barriers to radioactivity release;

(continued)

BASES

BACKGROUND (continued)

- Type D - Provide information to indicate the operation of individual safety systems and other plant systems. These variables are to help the operator make appropriate decisions in using the individual systems in mitigating the consequences of an accident; and
- Type E - Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat.

These key variables are identified by the unit specific Regulatory Guide 1.97 analyses (Ref. 1). These analyses identify the unit specific Type A and Category 1 variables and provide justification for deviating from the NRC proposed list of Category 1 variables.

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the operability of Regulatory Guide 1.97 Types A, B, C, D, and E Category 1 variables so that the control room operating staff can:

- Perform the diagnoses specified in the emergency operating procedures for identifying events and taking pre-planned manual actions for the primary success path of DBAs (e.g., loss of coolant accident (LOCA));
- Take the specified, pre-planned, manually controlled actions for which no automatic control is provided and that are required for safety systems to accomplish their safety function;
- Monitor performance of individual safety systems;
- Determine whether systems important to safety are performing their intended functions;
- Determine the likelihood of a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public, to estimate the magnitude of any impending threat, and monitor the magnitude of any releases.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Non-Type A Category 1 instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, Non-Type A Category 1 variables are important for reducing public risk.

LCO

The PAM Instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, which provide information required by the control room operators to identify events and perform certain manual actions specified in the unit Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses Regulatory Guide 1.97 instruments that have been designated Non-Type A Category 1.

The OPERABILITY of the PAM instrumentation ensures there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with the recommendations of Reference 1.

LCO 3.3.3 requires two OPERABLE channels for most Functions. Two OPERABLE channels ensure no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident.

Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information. More than two channels are required for some Functions because failure of one accident monitoring channel results in information ambiguity (that is, the redundant displays disagree) that could lead operators to defeat or fail to accomplish a required safety function.

One exception to the two channel requirement is Containment Isolation Valve (CIV) Position. In this case, the important information is the status of the containment penetrations. The LCO requires one position indicator for each active CIV. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve and prior knowledge of a passive valve, or via system boundary status. For example, if a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

(continued)

BASES

LCO (continued)

Another exception to the two channel requirement is RCS hot and cold leg temperature. One channel is sufficient because the loop temperatures are normally similar in value, and there is other adequate instrumentation to verify abnormal readings in one channel.

A third exception is the steam generator water level (wide range). One channel is sufficient because the wide range levels are back up measurements for the auxiliary feedwater flow (two channels).

A fourth exception is AFW valve position. This is acceptable since verification of adequate AFW flow and SG level ensures that the AFW valves are in the correct position.

Table 3.3.3-1 provides a list of all Category 1 variables. All Category 1 variables are normally required to meet Regulatory Guide 1.97 Category 1 (Ref. 2) design and qualification requirements for seismic and environmental qualification, single failure criterion, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display.

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1.

1, 2. Intermediate Range Neutron Flux and Source Range Neutron Flux

Intermediate Range Neutron Flux and Source Range Neutron Flux indication is provided to verify reactor shutdown. The two ranges are necessary to cover the full range of flux that may occur post accident. The Intermediate Range Neutron Flux indication is a non-Type A, Category 1 variable.

Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

Two Notes modify the APPLICABILITY of the Intermediate Range Neutron Flux indication to recognize that the Intermediate Range Neutron Flux channels is not required OPERABLE above the P-10 (Power Range Neutron Flux) interlock when in MODE 1 and below the P-6 (Intermediate Range Neutron Flux) interlock in MODE 2.

A Note modifies the APPLICABILITY of the Source Range Neutron Flux indication to recognize that the Source Range Neutron Flux channel is not required OPERABLE above the P-6 (Intermediate Range Neutron Flux) interlock.

(continued)

BASES

LCO (continued)

3, 4. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures

RCS Hot (T-Hot) and Cold (T-Cold) Leg Temperatures are Category 1 variables provided for verification of natural circulation and core cooling and long term surveillance.

RCS hot leg temperature is also used as an input to determine RCS subcooling margin. RCS subcooling margin and/or reactor vessel water level is used to make decisions to terminate Safety Injection (SI), if still in progress, or to re-initiate SI if it has been stopped. RCS subcooling margin is also used for unit stabilization and cooldown control.

In addition, RCS cold leg temperature is used in conjunction with RCS hot leg temperature to verify the unit conditions necessary to establish natural circulation in the RCS and verify adequate core cooling. The T-Hot and T-Cold channels provide indication over a range of 50°F to 700°F.

5. Reactor Coolant System Pressure (Wide Range)

RCS wide range pressure is a Category 1 variable provided for event identification, verification of core cooling and RCS integrity long term surveillance.

Wide-range RCS loop pressure is measured by 3 channels of pressure transmitters with a span of 0 - 3000 psig. Control room indications are provided by panel meters.

RCS pressure is used to verify delivery of SI flow to RCS from at least one train when the RCS pressure is below the pump shutoff head. RCS pressure is also used to verify closure of manually closed spray line valves and pressurizer power operated relief valves (PORVs).

In addition to these verifications, RCS pressure is used for determining RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or re-initiation of SI if it has been stopped. RCS subcooling margin is also used for unit stabilization and cooldown control. RCS pressure can also be used:

- to determine whether to terminate actuated SI or to re-initiate stopped SI;
- as reactor coolant pump (RCP) trip criteria; and
- to make a determination on the nature of the accident in progress and where to go next in the procedure.

(continued)

BASES

LCO

5. Reactor Coolant System Pressure (Wide Range) (continued)

RCS pressure is also related to three decisions about depressurization. They are:

- to determine whether to proceed with primary system depressurization;
- to verify termination of depressurization; and
- to determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

A final use of RCS pressure is to determine whether to operate the pressurizer heaters.

RCS pressure is a Type A variable because the operator uses this indication to identify events and to monitor the cooldown of the RCS following a steam generator tube rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting steam generator (SG) pressure or level, would use this indication.

6. Reactor Vessel Water Level

Reactor Vessel Water Level, a Type A, Category 1 variable is provided for:

- SI re-initiation criteria,
- Pressurizer Level Control,
- Criteria for manually re-starting ECCS pumps,
- Criteria for closing CLA isolation valves,
- RCS Pressure Control,
- Verification and long term surveillance of core cooling,
- Accident diagnosis,
- Determination of reactor coolant inventory adequacy, and
- Pressurizer heater control

The Reactor Vessel Level Instrumentation System (RVLIS) provides a direct measurement of the liquid level above the bottom of the reactor vessel up to the top of the reactor vessel. Indication is in percent of this distance (i.e., the reactor vessel bottom is 0% and the vessel top is 100%). It also has a dynamic range vessel liquid content (% LIQ) normalized from 20% to 100%. Normalization corrects the transmitted level information for the RCP operational configuration so that the

(continued)

BASES

LCO

6. Reactor Vessel Water Level (continued)

accurate dynamic % LIQ is indicated regardless of the pattern of pumps running or the fluid density. Control room indications are provided through the Common Q PAMS flat panel display. The Common Q PAMS flat panel display is the primary indication used by the operator during an accident.

7. Containment Sump Water Level (Wide Range)

Containment Sump Water Level is provided for event identification, and verification and long term surveillance of RCS integrity.

Containment Sump Water Level is used to:

- Verify water source for recirculation mode of ECCS operation after a LOCA.
- Determine whether high energy line rupture has occurred inside or outside containment.

8. Containment Lower Compartment Atmospheric Temperature

The lower compartment temperature monitors will verify the temperatures in the lower compartment after an accident with display in the main control room. The monitoring system consists of two channels with a range of 0°F to 350°F.

9. Containment Pressure (Wide Range)

Containment Pressure (Wide Range), a non-Type A Category 1 variable, is provided for verification of RCS and containment OPERABILITY.

Containment Pressure (Wide Range) instrumentation consists of two recorded trains on separate power supplies with a range of -5 psig to +60 psig.

Containment pressure wide range is used to monitor the post accident containment pressure up to the rupture pressure of containment to indicate potential containment breach.

(continued)

BASES

LCO (continued)

10. Containment Pressure (Narrow Range)

Containment Pressure (Narrow Range) is provided to determine margin to containment design pressure. The narrow range monitors are also used in event identification to monitor containment conditions following a break inside containment and to verify if the accident is being properly controlled. The narrow range instrumentation has a range of -2 psig to +15 psig.

11. Containment Isolation Valve Position

CIV Position, a non-Type A Category 1 variable, is provided for verification of Containment OPERABILITY, and verification of isolation after receipt of Phase A and/or Phase B isolation signals.

When used to verify valve closure for Phase A and/or Phase B isolation, the important information is the isolation status of the containment penetrations. The LCO requires one channel of valve position indication in the control room to be OPERABLE for each active CIV in a containment penetration flow path, i.e., two total channels of CIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active CIV having control room indication, Note (i) from Table 3.3.3-1 requires a single channel of valve position indication to be OPERABLE. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve, as applicable and prior knowledge of a passive valve, or via system boundary status. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

A Note to the Required Channels states that the Function is not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, pressure relief valve, or check valve with flow through the valve secured.

12. Containment Radiation (High Range)

Containment Radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans.

Containment radiation level is also used to determine if a loss of reactor coolant or secondary coolant has occurred.

(continued)

BASES

LCO (continued)

13. RCS Pressurizer Level

Pressurizer Level is one factor used to determine whether to terminate SI, if still in progress, or to re-initiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition.

Pressurizer Level instrumentation consists of the three differential pressure transmitters and associated instrumentation used to measure pressurizer level. The channels provide indication over the entire distance between taps.

14, 15. Steam Generator Water Level (Wide Range and Narrow Range)

SG Water Level is provided to monitor operation of decay heat removal via the SGs. The non-Type A Category 1 indication of SG level is the wide range level instrumentation.

Temperature compensation of wide range SG level indication is performed manually by the operator. The indication is cold calibrated. The uncompensated level signal is input to the plant computer for control room indications, and is used for diverse indication of AFW flow.

Narrow range steam generator level is used to make a determination on the nature of the accident in progress, e.g., verify a steam generator tube rupture. SG level (Narrow Range) is also used to help identify the ruptured steam generator following a tube rupture and verify that the intact steam generators are an adequate heat sink for the reactor. Narrow range steam generator water level is used when verifying plant conditions for termination of SI during secondary plant high energy line breaks outside containment.

16. AFW Valve Status

The status of each AFW swap over to Essential Raw Cooling Water (ERCW) valve is monitored with non-Type A Category 1 indication in the control room. Indication on each valve for fully open or fully closed position is provided. AFW valve status is monitored to give verification to the operator that automatic transfer to ERCW has taken place.

(continued)

BASES

LCO (continued)

17, 18, 19, 20. Core Exit Temperature

Core Exit Temperature is provided for verification and long term surveillance of core cooling.

Core exit thermocouples, in conjunction with RCS wide range temperatures, are sufficient to provide indication of radial distribution of the coolant enthalpy rise across representative sections of the core. Core Exit Temperature is used to support determination of whether to terminate SI, if still in progress, or to re-initiate SI if it has been stopped. Core Exit Temperature is also used for unit stabilization and cooldown control.

The Common Q Post Accident Monitoring (PAM) System is used to monitor the core exit thermocouples. There are two isolated systems, with each system monitoring at least four thermocouples per quadrant. The flat panel display gives the representative value, the high quadrant value, and the individual values.

Two OPERABLE channels are required in each quadrant to provide adequate indication of coolant temperature rise in representative regions of the core. Two isolated channels of two thermocouples each ensure a single failure will not disable the ability to identify significant temperature gradients.

21. Auxiliary Feedwater Flow

AFW Flow is provided to monitor operation of decay heat removal via the SGs.

Redundant monitoring capability is provided by two independent trains of instrumentation for each SG. Each differential pressure transmitter provides an input to a control room indicator. Since the primary indication used by the operator during an accident is the control room indicator, the PAM specification deals specifically with this portion of the instrument channel.

AFW flow is used three ways:

- to verify AFW flow to the SGs;
- to determine whether to terminate SI if still in progress, in conjunction with SG water level (narrow range); and
- to regulate AFW flow so that the SG tubes remain covered.

(continued)

BASES

LCO (continued)

22. Reactor Coolant System Subcooling Margin Monitor

The RCS subcooling margin monitor is used to determine the temperature margin to saturation of the primary coolant. Control room indications are provided through the Common Q PAMS flat panel display and digital panel meters. The Common Q PAMS flat panel display is the primary indication used by the operator during an accident.

23. Refueling Water Storage Tank Level

RWST water level is used to verify the water source availability to the ECCS and Containment Spray (CS) Systems. It alerts the operator to manually switch the CS suction from the RWST to the containment sump. It may also provide an indication of time for initiating cold leg recirculation from the sump following a LOCA.

24. Steam Generator Pressure

Steam pressure is used to determine if a high energy secondary line rupture has occurred and the availability of the steam generators as a heat sink. It is also used to verify that a faulted steam generator is isolated. Steam pressure may be used to ensure proper cooldown rates or to provide a diverse indication for natural circulation cooldown.

25. Auxiliary Building Passive Sump Level

Auxiliary Building Passive Sump Level, a non-Type A Category 1 variable, monitors the sump level in the auxiliary building. The two functions of this indication are to monitor for a major breach of the spent fuel pit and to monitor for an RCS breach in the auxiliary building (i.e., an RHR or CVCS line break). The purpose is to verify that radioactive water does not leak to the auxiliary building. The Auxiliary Building Passive Sump Level monitor consists of two channels on separate power supply. One channel is recorded. The calibrated range of the two monitors is 12.5" to 72.5".

BASES

APPLICABILITY

The PAM instrumentation LCO is applicable as shown in Table 3.3.3-1. These variables are related to the diagnosis and pre-planned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies when one or more Functions have one required channel that is inoperable. Required Action A.1 requires restoring the inoperable channel 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.

Condition A is modified by a Note that excludes single channel Functions 3, 4, 14, and 16.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies initiation of actions in Specification 5.9.8, "PAMS Report," which requires a written report to be submitted to the NRC immediately. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

(continued)

BASES

ACTIONS (continued)

C.1

Condition C applies when one or more Functions have two inoperable required channels (i.e., two channels inoperable in the same Function). Condition C also applies to single channel Functions 3, 4, 14, and 16 when the one required channel is inoperable. Required Action C.1 requires restoring one channel in the Function(s) to OPERABLE status within 7 days.

The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function or the single required channel inoperable in the single channel Functions is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

D.1

Condition D applies when the Required Action and associated Completion Time of Condition C are not met. Required Action D.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C, and the associated Completion Time has expired, Condition D is entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1 and E.2

If the Required Action and associated Completion Time of Condition C are not met and Table 3.3.3-1 directs entry into Condition E, the plant must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

F.1

Alternate means may be temporarily installed for monitoring reactor vessel water level and Containment Area Radiation if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. Alternate means would be developed and tested prior to use. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.9.8, in the Administrative Controls section of the TS. 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

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure 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 two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar unit instruments located throughout the unit.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1 (continued)

The Frequency of 31 days is based on operating experience that demonstrates that 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 LCO required channels.

SR 3.3.3.2

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter with the necessary range and accuracy. This SR is modified by two Notes. Note 1 excludes neutron detectors. The calibration method for neutron detectors is specified in the Bases of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." Note 2 indicates that Functions 11 and 16 (valve position indicators) are excluded from the CHANNEL CALIBRATION. The Frequency is based on operating experience and consistency with the typical industry refueling cycle.

SR 3.3.3.3

SR 3.3.3.3 is the performance of a TADOT. This test is performed every 18 months. The test checks operation of the containment isolation valve position indicators and AFW valve position indicators. The Frequency is based on the known reliability of the indicators and has been shown to be acceptable through operating experience.

This SR has been modified by two Notes. Note 1 excludes verification of setpoints for the valve position indicators. Note 2 indicates that this SR is only applicable to Functions 11 and 16, which are the only Functions with valve position indicators.

BASES (continued)

REFERENCES

1. NUREG-0847, Safety Evaluation Report, Supplement Number 9, June 16, 1992, Section 7.5.2, "Post Accident Monitoring System."

2. Regulatory Guide 1.97, Revision 2, December 1980, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident."

3. NUREG-0737, "Clarification of TMI Action Plan Requirements," Supplement 1, January 1983.

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AFW) System and the steam generator (SG) safety valves or the SG atmospheric dump valves (ADVs) can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Reactor Coolant System (RCS) from outside the control room allows extended operation in MODE 3.

If the control room becomes inaccessible, the operators can establish control in the auxiliary control room, and place and maintain the unit in MODE 3. Not all controls and necessary transfer switches are located in the auxiliary control room. Some controls and transfer switches will have to be operated locally at the switchgear, motor control panels, or other local stations. Some instrumentation serves a dual purpose in providing information to the operator. This instrumentation includes the pressurizer pressure indicator, which can be used to indicate pressurizer pressure and RCS wide range pressure, and the SG pressure indicators, which can be used to indicate SG pressure and SG T_{sat}. Additionally, controls for the RCS PORVs can be used for both RCS pressure and inventory control. The unit automatically reaches MODE 3 following a unit shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the remote shutdown control and instrumentation functions ensures there is sufficient information available on selected unit parameters to place and maintain the unit in MODE 3 should the control room become inaccessible. Should it be necessary to go to MODE 4 or MODE 5, decay heat removal via the Residual Heat Removal (RHR) System is available to support the transition.

The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a capability to promptly shut down and maintain the unit in a safe condition in MODE 3.

BASES (continued)

APPLICABLE SAFETY ANALYSES

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

The Remote Shutdown System is considered an important contributor to the reduction of unit risk to accidents and as such it has been retained in the Technical Specifications as indicated in 10 CFR 50.36(c)(2)(ii).

LCO

The Remote Shutdown System LCO provides the OPERABILITY requirements of the instrumentation and controls necessary to place and maintain the unit in MODE 3 from a location other than the control room. The instrumentation and controls typically required are listed in Table 3.3.4-1 in the accompanying LCO.

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

- Core reactivity control (initial and long term);
- RCS pressure control;
- Decay heat removal via the AFW System and the SG safety valves or SG ADVs;
- RCS inventory control via charging and letdown flow;
- Decay Heat Removal via RHR System;
- Safety support systems though not specifically listed in Table 3.3.4-1, for the above Functions, including service water, component cooling water, reactor containment fan cooler units, auxiliary control air compressors, and onsite power, including the diesel generators are required as discussed in FSAR Section 7.4 (Reference 2).

A Function of a Remote Shutdown System is OPERABLE if all instrument and control channels needed to support the Remote Shutdown System Function are OPERABLE. References 3 and 4 provide additional information on required equipment. In some cases, Table 3.3.4-1 may indicate that the required information or control capability is available from several alternate sources. In these cases, the Function is OPERABLE as long as one channel of any of the alternate information or control sources is OPERABLE.

(continued)

BASES

LCO (continued)

The remote shutdown instrument and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure the instruments and control circuits will be OPERABLE if unit conditions require that the Remote Shutdown System be placed in operation.

APPLICABILITY

The Remote Shutdown System LCO is applicable in MODES 1, 2, and 3. This is required so that the unit can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the facility is already subcritical and in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument control functions if control room instruments or controls become unavailable.

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. Separate Condition entry is allowed for each Function listed on Table 3.3.4-1.

The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System are inoperable. This includes any Function listed in Table 3.3.4-1, as well as the control and transfer switches.

The Required Action is to restore the required Function to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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

As specified in the Surveillance, a CHANNEL CHECK is only required for those channels which are normally energized.

The Frequency of 31 days is based upon operating experience which demonstrates that 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 LCO required channels.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.2

SR 3.3.4.2 verifies each required Remote Shutdown System control circuit and transfer switch performs the intended function. This verification is performed from the auxiliary control room and locally, as appropriate. Operation of the equipment from the remote shutdown panel is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the plant can be placed and maintained in MODE 3 from the auxiliary control room and the local control stations. 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. However, this Surveillance is not required to be performed only during a unit outage. Operating experience demonstrates that remote shutdown control channels usually pass the Surveillance test when performed at the 18-month Frequency.

SR 3.3.4.3

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

The Frequency of 18 months is based upon operating experience and consistency with the typical industry refueling cycle.

SR 3.3.4.4

SR 3.3.4.4 is the performance of a TADOT every 18 months. This test should verify the OPERABILITY of the reactor trip breakers (RTBs) open and closed indication on the remote shutdown panel, by actuating the RTBs. The Frequency is based upon operating experience and consistency with the typical industry refueling outage.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria 19, "Control Room."

2. Watts Bar FSAR Section 7.4, "Systems Required for Safe Shutdown."

3. TVA Calculation WBN-OSG4-193, "Auxiliary Control System Required Equipment per GDC 19."

4. Design Criteria WB-DC-40-58, "Auxiliary Control System."

B 3.3 INSTRUMENTATION

B 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate an LOP start if a loss of voltage or degraded voltage condition occurs in the switchyard. There are four LOP start signals, one for each 6.9 kV shutdown board.

Three degraded voltage relays (one per phase) are provided on each 6.9 kV Shutdown Board for detecting a sustained undervoltage condition. The relays are combined in a two-out-of-three logic configuration to generate a supply breaker trip signal if the voltage is below 96% for 10 seconds (nominal). Additionally, three undervoltage relays (one per phase) are provided on each 6.9 kV Shutdown Board for the purpose of detecting a loss of voltage condition. These relays are combined in a two-out-of-three logic to generate a supply breaker trip signal if the voltage is below 87% for 0.75 seconds (nominal).

Once the supply breakers have been opened, either one of two induction disk type relays, which have a voltage setpoint of 70% of 6.9 kV (nominal, decreasing) and an internal time delay of 0.5 seconds (nominal) at zero volts, will start the diesel generators. Four additional induction disk type relays, in a logic configuration of one-of-two taken twice which have a voltage setpoint of 70% of 6.9 kV (nominal, decreasing) and an internal time delay of 3 seconds (nominal), at zero volts, will initiate load shedding of the 6.9 kV shutdown board loads and selected loads on the 480 V shutdown boards and close the 480 V shutdown boards' current limiting reactor bypass breaker. The LOP start actuation is described in FSAR Section 8.3, "Onsite (Standby) Power System" (Ref. 1).

Trip Setpoints and Allowable Values

The Trip Setpoints used in the relays and timers are based on the analytical limits presented in TVA calculations (References 3, 4, and 5). The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and time delays are taken into account.

The actual nominal Trip Setpoint entered into the relays is more conservative than that required by the Allowable Value. If the measured setpoint does not exceed the Allowable Value, the relay is considered OPERABLE.

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

Setpoints adjusted in accordance with the Allowable Value ensure that the consequences of accidents will be acceptable, providing the unit is operated from within the LCOs at the onset of the accident and that the equipment functions as designed.

Allowable Values are specified for each Function in Table 3.3.5-1. Nominal Trip Setpoints are also specified in the unit specific setpoint calculations. The nominal setpoints are selected to ensure that the setpoint measured by the surveillance procedure does not exceed the Allowable Value if the relay is performing as required. If the measured setpoint does not exceed the Allowable Value, the relay is considered OPERABLE. Operation with a Trip Setpoint less conservative than the nominal Trip Setpoint, but within the Allowable Value, is acceptable provided that operation and testing is consistent with the assumptions of the unit specific setpoint calculation. Each Allowable Value specified is more conservative than the analytical limit assumed in the transient and accident analyses in order to account for instrument uncertainties appropriate to the trip function. These uncertainties are defined in Reference 3.

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS).

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power. The analyses assume a non-mechanistic DG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions.

The channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 2, in which a loss of offsite power is assumed.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay, if applicable. The response times for ESFAS actuated equipment in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," include the appropriate DG loading and sequencing delay.

The LOP DG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO for LOP DG Start Instrumentation requires that the loss of voltage, degraded voltage, load shed, and DG Start Functions shall be OPERABLE in MODES 1, 2, 3, and 4 when the LOP DG Start Instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, the Functions must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed. Loss of the LOP DG Start Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents. During the loss of offsite power the DG powers the motor driven auxiliary feedwater pumps. Failure of these pumps to start would leave only one turbine driven pump, as well as an increased potential for a loss of decay heat removal through the secondary system.

APPLICABILITY

The LOP DG Start Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE so that it can perform its function on an LOP or a degraded voltage condition on the 6.9 kV Shutdown Board.

ACTIONS

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the Function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection Function affected.

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

(continued)

BASES

ACTIONS (continued)

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in the LCO. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the LOP DG start Function with one channel per bus inoperable.

If one channel is inoperable, Required Action A.1 requires the channel to be restored to OPERABLE status within 6 hours. The specified Completion Time is reasonable considering the Function remains fully OPERABLE on every bus and the low probability of an event occurring during these intervals.

A Note has been added to Required Action A.1 to direct entry into the applicable Conditions and Required Actions of LCO 3.3.2, "ESFAS Instrumentation," for inoperable Auxiliary Feedwater start instrumentation. The load shed relays required by this LCO also generate the start signal for the LOP start of the turbine driven auxiliary feedwater pump required in LCO 3.3.2. The Required Actions of LCO 3.3.2 are entered in addition to the requirements of this LCO.

B.1

Condition B applies when more than one channel on a single bus is inoperable.

Required Action B.1 requires restoring all but one channel to OPERABLE status. The 1-hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

(continued)

BASES

ACTIONS (continued)

C.1

Condition C applies to each of the LOP DG start Functions when the Required Action and associated Completion Time for Condition A or B are not met.

In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources - Operating," or LCO 3.8.2, "AC Sources - Shutdown," for the DG made inoperable by failure of the LOP DG start instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure unit safety.

SURVEILLANCE REQUIREMENTS

A Note has been added to refer to Table 3.3.5-1 to determine which Surveillance Requirements apply for each LOP Function.

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT. This test is performed every 92 days. The test checks operation of the undervoltage and degraded voltage relays that provide actuation signals. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as left and as found setting are consistent with those established by the setpoint methodology. The Frequency is based on the known reliability of the relays and timers and the redundancy available, and has been shown to be acceptable through operating experience.

This SR has been modified by a Note that excludes verification of setpoints for relays/timers. Relay/timer setpoints require elaborate bench calibration and are verified during a CHANNEL CALIBRATION.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay, as shown in Reference 1.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2 (continued)

A CHANNEL CALIBRATION is performed every 6 months. CHANNEL CALIBRATION is a check of the four functions. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as left and as found setting are consistent with those established by the setpoint methodology.

The Frequency of 6 months is based on operating experience and is justified by the assumption of a 6-month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.3

SR 3.3.5.3 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay, as shown in Reference 1.

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the four functions. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as left and as found setting are consistent with those established by the setpoint methodology.

The Frequency of 18 months is based on operating experience and consistency with the typical industry refueling cycle and is justified by the assumption of an 18-month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

BASES (continued)

REFERENCES

1. Watts Bar FSAR, Section 8.3, "Onsite (Standby) Power System."

2. Watts Bar FSAR, Section 15.0, "Accident Analysis."

3. TVA Calculation WBPE2119202001, "6.9 kV Shutdown & Logic Boards Undervoltage Relays Requirements / Demonstrated Accuracy Calculation."

4. TVA Calculation TDR SYS.211-LV1, "Demonstrated Accuracy Calculation TDR SYS.211-LV1."

5. TVA Calculation TDR SYS.211-DS1, "Demonstrated Accuracy Calculation TDR SYS.211-DS1."

B 3.3 INSTRUMENTATION

B 3.3.6 Containment Vent Isolation Instrumentation

BASES

BACKGROUND

Containment Vent Isolation Instrumentation closes the containment isolation valves in the Containment Purge System. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. The Reactor Building Purge System may be in use during reactor operation and with the reactor shutdown.

Containment vent isolation is initiated by a safety injection (SI) signal or by manual actuation. The Bases for LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," discuss initiation of SI signals.

Redundant and independent gaseous radioactivity monitors measure the radioactivity levels of the containment purge exhaust, each of which will initiate its associated train of automatic Containment Vent Isolation upon detection of high gaseous radioactivity.

The Reactor Building Purge System has inner and outer containment isolation valves in its supply and exhaust ducts. This system is described in the Bases for LCO 3.6.3, "Containment Isolation Valves."

APPLICABLE SAFETY ANALYSES

The containment isolation valves for the Reactor Building Purge System close within six seconds following the DBA. The containment vent isolation radiation monitors act as backup to the SI signal to ensure closing of the purge air system supply and exhaust valves. Containment isolation in turn ensures meeting the containment leakage rate assumptions of the safety analyses, and ensures that the calculated accidental offsite radiological doses are below 10 CFR 100 (Ref. 1) limits.

The Containment Vent Isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The LCO requirements ensure that the instrumentation necessary to initiate Containment Vent Isolation, listed in Table 3.3.6-1, is OPERABLE.

1. Manual Initiation

The LCO requires two channels OPERABLE. The operator can initiate Containment Vent Isolation at any time by using either of two switches in the control room or from local panel(s). Either switch actuates both trains. This action will cause actuation of all components in the same manner as any of the automatic actuation signals. These manual switches also initiate a Phase A isolation signal.

The LCO for Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

Each channel consists of one selector switch and the interconnecting wiring to the actuation logic cabinet.

2. Automatic Actuation Logic and Actuation Relays

The LCO requires two trains of Automatic Actuation Logic and Actuation Relays OPERABLE to ensure that no single random failure can prevent automatic actuation.

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b, SI. The applicable MODES and specified conditions for the containment vent isolation portion of the SI Function is different and less restrictive than those for the SI role. If one or more of the SI Functions becomes inoperable in such a manner that only the Containment Vent Isolation Function is affected, the Conditions applicable to the SI Functions need not be entered. The less restrictive Actions specified for inoperability of the Containment Vent Isolation Functions specify sufficient compensatory measures for this case.

(continued)

BASES

LCO (continued)

3. Containment Radiation

The LCO specifies two required channels of radiation monitors to ensure that the radiation monitoring instrumentation necessary to initiate Containment Vent Isolation remains OPERABLE.

For sampling systems, channel OPERABILITY involves more than OPERABILITY of the channel electronics. OPERABILITY may also require correct valve lineups and sample pump operation, as well as detector OPERABILITY, if these supporting features are necessary for trip to occur under the conditions assumed by the safety analyses.

Table 3.3.6-1 specifies the Allowable Values (AVs) for the Containment Purge Exhaust Radiation Monitors. The Allowable Value is based on expected concentrations for a small break LOCA, which is more restrictive than 10 CFR 100 limits. The Allowable Value specified is more conservative than the analytical limit assumed in the safety analysis in order to account for instrument uncertainties appropriate to the trip function. The actual nominal Trip Setpoint is normally still more conservative than that required by the Allowable Value. If the setpoint does not exceed the Allowable Value, the radiation monitor is considered OPERABLE.

4. Safety Injection (SI)

Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements.

APPLICABILITY

The Manual Initiation, Automatic Actuation Logic and Actuation Relays, Safety Injection, and Containment Radiation Functions are required OPERABLE in MODES 1, 2, 3, and 4. Under these conditions, the potential exists for an accident that could release significant fission product radioactivity into containment. Therefore, the Containment Vent Isolation Instrumentation must be OPERABLE in these MODES. See additional discussion in the Background and Applicable Safety Analysis sections.

While in MODES 5 and 6, the Containment Vent Isolation Instrumentation need not be OPERABLE since the potential for radioactive releases is minimized and operator action is sufficient to ensure post accident offsite doses are maintained within the limits of Reference 1.

BASES (continued)

ACTIONS

The most common cause of channel inoperability is outright failure or drift sufficient to exceed the tolerance allowed by unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately, and the appropriate Condition entered.

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.6-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the failure of one containment purge isolation radiation monitor channel. Since the two containment radiation monitors are both gaseous detectors, failure of a single channel may result in loss of the redundancy. Consequently, the failed channel must be restored to OPERABLE status. The 4 hours allowed to restore the affected channel is justified by the low likelihood of events occurring during this interval, and recognition that one or more of the remaining channels will respond to most events.

B.1

Condition B applies to all Containment Vent Isolation Functions and addresses the train orientation of the Solid State Protection System (SSPS) and the master and slave relays for these Functions. It also addresses the failure of multiple radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1.

If a train is inoperable, multiple channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action for the applicable Conditions of LCO 3.6.3 is met for each valve made inoperable by failure of isolation instrumentation. A Note has been added above the Required Actions to allow one train of actuation logic to be placed in bypass and to delay entering the Required Actions for up to four hours to perform surveillance testing provided the other train is OPERABLE. The 4-hour allowance is consistent with the Required Actions for actuation logic trains in LCO 3.3.2, "Engineered Safety Features Actuation System

(continued)

BASES

ACTIONS

B.1 (continued)

Instrumentation" and allows periodic testing to be conducted while at power without causing an actual actuation. The delay for entering the Required Actions relieves the administrative burden of entering the Required Actions for isolation valves inoperable solely due to the performance of surveillance testing on the actuation logic and is acceptable based on the OPERABILITY of the opposite train.

SURVEILLANCE REQUIREMENTS

.A Note has been added to the SR Table to clarify that Table 3.3.6 1 determines which SRs apply to which Containment Vent Isolation Functions.

SR 3.3.6.1

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

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

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.2

SR 3.3.6.2 is the performance of an ACTUATION LOGIC TEST. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is pulse tested for continuity. This verifies that the logic modules are OPERABLE and there is an intact voltage signal path to the master relay coils. This test is performed every 92 days on a STAGGERED TEST BASIS. The Surveillance interval is justified in Reference 4.

The SR is modified by a Note stating that the surveillance is only applicable to the actuation logic of the ESFAS instrumentation.

SR 3.3.6.3

SR 3.3.6.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage is injected to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. This test is performed every 92 days on a STAGGERED TEST BASIS. The Surveillance interval is justified in Reference 4.

The SR is modified by a Note stating that the surveillance is only applicable to the master relays of the ESFAS instrumentation.

SR 3.3.6.4

A COT is performed every 92 days on each required channel to ensure the entire channel will perform the intended Function. The Frequency is based on the staff recommendation for increasing the availability of radiation monitors according to NUREG-1366 (Ref. 2). This test verifies the capability of the instrumentation to provide the containment vent system isolation. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as left and as found setting are consistent with those established by the setpoint methodology.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.5

SR 3.3.6.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation mode is either allowed to function or is placed in a condition where the relay contact operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation mode is prevented from operation by the SLAVE RELAY TEST circuit. For this latter case, contact operation is verified by a continuity check of the circuit containing the slave relay. This test is performed every 92 days. The Frequency is acceptable based on instrument reliability and industry operating experience.

For ESFAS slave relays which are Westinghouse type AR or Potter & Brumfield MDR series relays, the SLAVE RELAY TEST is performed every 18 months. The frequency is based on the relay reliability assessments presented in References 3 and 5. These reliability assessments are relay specific and apply only to Westinghouse type AR and Potter & Brumfield MDR series relays with AC coils. Note that for normally energized applications, the relays may require periodic replacement in accordance with the guidance given in References 3 and 5.

SR 3.3.6.6

SR 3.3.6.6 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and is performed every 18 months. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.).

For these tests, the relay trip setpoints are verified and adjusted as necessary. The Frequency is based on the known reliability of the Function and the redundancy available, and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.7

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as left and as found settings are consistent with those established by the setpoint methodology.

The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance."

2. NUREG-1366, "Improvement to Technical Specification Surveillance Requirements," December 1992.

3. WCAP-13877-P-A, Revision 2, “Reliability Assessment of Westinghouse Type AR Relays Used as SSPS Slave Relays.”

4. WCAP-15376-P-A, Revision 1, “Risk-Informed Assessment of the RTS and ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times,” March 2003.

5. WCAP-13878-P-A, Revision 2, “Reliability Assessment of Potter & Brumfield MDR Series Relays.”

B 3.3 INSTRUMENTATION

B 3.3.7 Control Room Emergency Ventilation System (CREVS) Actuation Instrumentation

BASES

BACKGROUND

The CREVS provides an enclosed control room environment from which the unit can be operated following an uncontrolled release of radioactivity. During normal operation, the Control Building Ventilation System provides control room ventilation. Upon receipt of an actuation signal, the CREVS initiates filtered ventilation and pressurization of the control room. This system is described in the Bases for LCO 3.7.10, "Control Room Emergency Ventilation System (CREVS)."

The actuation instrumentation consists of redundant radiation monitors. A high radiation signal from any detector will initiate its associated trains of the CREVS. The control room operator can also initiate CREVS trains by manual switches in the control room. The CREVS is also actuated by a safety injection (SI) signal. The SI Function is discussed in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation."

APPLICABLE SAFETY ANALYSES

The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations.

The CREVS acts to terminate the supply of unfiltered outside air to the control room, initiate filtration, and emergency pressurization of the control room. These actions are necessary to ensure the control room is kept habitable for the operators stationed there during accident recovery and post accident operations by minimizing the radiation exposure of control room personnel.

In MODES 1, 2, 3, and 4, the radiation monitor actuation of the CREVS is a backup for the SI signal actuation. This ensures initiation of the CREVS during a loss of coolant accident or steam generator tube rupture.

The radiation monitor actuation of the CREVS in MODES 5 and 6 and during movement of irradiated fuel assemblies, is the primary means to ensure control room habitability in the event of a fuel handling or waste gas decay tank rupture accident.

The CREVS actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The LCO requirements ensure that instrumentation necessary to initiate the CREVS is OPERABLE.

1. Manual Initiation

The LCO requires two channels OPERABLE. The operator can initiate the CREVS at any time by using either of two switches in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO for Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

Each channel consists of one hand switch and the interconnecting wiring to the actuation logic relays.

2. Control Room Radiation

The LCO specifies two required Control Room Air Intake Radiation Monitors to ensure that the radiation monitoring instrumentation necessary to initiate the CREVS remains OPERABLE. One radiation monitor is dedicated to each train of CREVS.

For sampling systems, channel OPERABILITY involves more than OPERABILITY of channel electronics. OPERABILITY may also require correct valve lineups, sample pump operation, and filter motor operation, as well as detector OPERABILITY, if these supporting features are necessary for trip to occur under the conditions assumed by the safety analyses.

Only the Allowable Value is specified for the Control Room Air Intake Radiation Monitors in the LCO. The Allowable Value is based on 10 CFR 50, Appendix A, Criterion 19 exposure limits considering the most limiting accident, which has been determined to be a steam generator tube rupture event. This event is more limiting than a fuel handling accident event or a LOCA. The Allowable Value specified is more conservative than the analytical limit assumed in the safety analysis in order to account for instrument uncertainties appropriate to the trip function. The actual nominal Trip Setpoint is normally still more conservative than that required by the Allowable Value. If the setpoint does not exceed the Allowable Value, the radiation monitor is considered OPERABLE.

(continued)

BASES

LCO (continued)

3. Safety Injection

Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements.

APPLICABILITY

The CREVS Functions must be OPERABLE in MODES 1, 2, 3, 4, and during movement of irradiated fuel assemblies. The Functions must also be OPERABLE in MODES 5 and 6 when required for a waste gas decay tank rupture accident, to ensure a habitable environment for the control room operators.

ACTIONS

The most common cause of channel inoperability is outright failure or drift sufficient to exceed the tolerance allowed by the plant specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.7-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the actuation logic train Function of the CREVS, the radiation monitor channel Functions, and the manual channel Functions.

If one train is inoperable, or one radiation monitor channel is inoperable in one or more Functions, 7 days are permitted to restore it to OPERABLE status. The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.10. If the channel/train cannot be restored to OPERABLE status, one CREVS train must be placed in the emergency radiation protection mode of operation. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

(continued)

BASES

ACTIONS (continued)

B.1.1, B.1.2, and B.2

Condition B applies to the failure of two CREVS actuation trains, two radiation monitor channels, or two manual channels. The first Required Action is to place one CREVS train in the emergency radiation protection mode of operation immediately. This accomplishes the actuation instrumentation Function that may have been lost and places the unit in a conservative mode of operation. The applicable Conditions and Required Actions of LCO 3.7.10 must also be entered for the CREVS train made inoperable by the inoperable actuation instrumentation. This ensures appropriate limits are placed upon train inoperability as discussed in the Bases for LCO 3.7.10.

Alternatively, both trains may be placed in the emergency radiation protection mode. This ensures the CREVS function is performed even in the presence of a single failure.

C.1 and C.2

Condition C applies when the Required Action and associated Completion Time for Condition A or B have not been met and the plant is in MODE 1, 2, 3, or 4. The plant must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 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

Condition D applies when the Required Action and associated Completion Time for Condition A or B have not been met when irradiated fuel assemblies are being moved. Movement of irradiated fuel assemblies must be suspended immediately to reduce the risk of accidents that would require CREVS actuation.

E.1

Condition E applies when the Required Action and associated Completion Time for Condition A or B have not been met in MODE 5 or 6. Actions must be initiated to restore the inoperable train(s) to OPERABLE status immediately to ensure adequate isolation capability in the event of a waste gas decay tank rupture.

BASES (continued)

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.7-1 determines which SRs apply to which CREVS Actuation Functions.

SR 3.3.7.1

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

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

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

SR 3.3.7.2

A COT is performed once every 92 days on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the CREVS actuation. The Frequency is based on the known reliability of the monitoring equipment and has been shown to be acceptable through operating experience. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as left and as found setting are consistent with those established by the setpoint methodology.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.3

SR 3.3.7.3 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and is performed every 18 months. Each Manual Actuation Function is tested up to, and including, the relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.).

The Frequency is based on the known reliability of the Function and the redundancy available, and has been shown to be acceptable through operating experience.

The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

SR 3.3.7.4

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. There is a plant specific program which verifies that the instrument channel functions as required by verifying the as left and as found setting are consistent with those established by the setpoint methodology.

The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

REFERENCES None

BASES

B 3.3 INSTRUMENTATION

B 3.3.8 Auxiliary Building Gas Treatment (ABGTS) Actuation Instrumentation

BASES

BACKGROUND

The ABGTS ensures that radioactive materials in the fuel building atmosphere following a loss of coolant accident (LOCA) are filtered and adsorbed prior to exhausting to the environment. The system is described in the Bases for LCO 3.7.12, "Auxiliary Building Gas Treatment System (ABGTS)." The system initiates filtered exhaust of air from the fuel handling area, ECCS pump rooms, and penetration rooms automatically following receipt of a Containment Phase A Isolation signal. Initiation may also be performed manually as needed from the main control room.

There are a total of two channels, one for each train. A Phase A isolation signal from the Engineered Safety Features Actuation System (ESFAS) initiates auxiliary building isolation and starts the ABGTS. These actions function to prevent exfiltration of contaminated air by initiating filtered ventilation, which imposes a negative pressure on the Auxiliary Building Secondary Containment Enclosure (ABSCE).

APPLICABLE SAFETY ANALYSES

The ABGTS ensures that radioactive materials in the ABSCE atmosphere following a LOCA are filtered and adsorbed prior to being exhausted to the environment. This action reduces the radioactive content in the auxiliary building exhaust following a LOCA so that offsite doses remain within the limits specified in 10 CFR 100 (Ref. 1).

The ABGTS Actuation Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The LCO requirements ensure that instrumentation necessary to initiate the ABGTS is OPERABLE.

1. Manual Initiation

   The LCO requires two channels OPERABLE. The operator can initiate the ABGTS at any time by using either of two switches in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

   The LCO for Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

   Each channel consists of one hand switch and the interconnecting wiring to the actuation logic relays.

2. Containment Phase A Isolation

   Refer to LCO 3.3.2, Function 3.a, for all initiating Functions and requirements.

APPLICABILITY

The manual ABGTS initiation must be OPERABLE in MODES 1, 2, 3, and 4 to ensure the ABGTS operates to remove fission products associated with leakage after a LOCA. The Phase A ABGTS Actuation is also required in MODES 1, 2, 3, and 4 to remove fission products caused by post LOCA Emergency Core Cooling Systems leakage.

While in MODES 5 and 6, the ABGTS instrumentation need not be OPERABLE. See additional discussion in the Background and Applicable Safety Analysis sections.

BASES

ACTIONS

The most common cause of channel inoperability is outright failure or drift sufficient to exceed the tolerance allowed by unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.8-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the actuation logic train function from the Phase A Isolation and the manual initiation function. Condition A applies to the failure of a single actuation logic train, or manual channel. If one channel or train is inoperable, a period of 7 days is allowed to restore it to OPERABLE status. If the train cannot be restored to OPERABLE status, one ABGTS train must be placed in operation. This accomplishes the actuation instrumentation function and places the unit in a conservative mode of operation. The 7-day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this time is the same as that provided in LCO 3.7.12.

B.1.1, B.1.2, B.2

Condition B applies to the failure of two ABGTS actuation logic signals from the Phase A Isolation or two manual channels. The Required Action is to place one ABGTS train in operation immediately. This accomplishes the actuation instrumentation function that may have been lost and places the unit in a conservative mode of operation. The applicable Conditions and Required Actions of LCO 3.7.12 must also be entered for the ABGTS train made inoperable by the inoperable actuation instrumentation. This ensures appropriate limits are placed on train inoperability as discussed in the Bases for LCO 3.7.12.

Alternatively, both trains may be placed in the emergency radiation protection mode. This ensures the ABGTS Function is performed even in the presence of a single failure.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Condition C applies when the Required Action and associated Completion Time for Condition A or B have not been met and the plant is in MODE 1, 2, 3, or 4. The plant must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 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 3.3.8.1

SR 3.3.8.1 is the performance of a TADOT. This test is a check of the manual actuation functions and is performed every 18 months. Each manual actuation function is tested up to, and including, the relay coils. In some instances, the test includes actuation of the end device (e.g., pump starts, valve cycles, etc.). The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

The RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNB limits.

The RCS coolant average temperature limit is consistent with full power operation within the nominal operational envelope. Indications of temperature are averaged to determine a value for comparison to the limit. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. Flow rate indications are averaged to come up with a value for comparison to the limit. A lower RCS flow will cause the core to approach DNB limits.

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNBR criterion. This is the acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. The transients analyzed for include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.7, “Control Bank Insertion Limits;” LCO 3.2.3, “AXIAL FLUX DIFFERENCE (AFD);” and LCO 3.2.4, “QUADRANT POWER TILT RATIO (QPTR).”

The pressurizer pressure limit of 2214 psig and the RCS average temperature limit of 593.2°F correspond to analytical limits of 2185 psig and 594.2°F used in the safety analyses, with allowance for measurement uncertainty.

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO specifies limits on the monitored process variables - pressurizer pressure, RCS average temperature, and RCS total flow rate - to ensure the core operates within the limits assumed in the safety analyses. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

RCS total flow rate contains a measurement error of 1.6% (process computer) or 1.8% (control board indication) based on performing a precision heat balance and using the result to calibrate the RCS flow rate indicators. Potential fouling of the feedwater venturi, which might not be detected, could bias the result from the precision heat balance in a nonconservative manner. Therefore, a penalty of 0.1% for undetected fouling of the feedwater venturi raises the nominal flow measurement allowance to 1.7% (process computer) or 1.9% (control board indication).

Any fouling that might bias the flow rate measurement greater than 0.1% can be detected by monitoring and trending various plant performance parameters. If detected, either the effect of the fouling shall be quantified and compensated for in the RCS flow rate measurement or the venturi shall be cleaned to eliminate the fouling. The LCO numerical values for pressure, temperature, and flow rate are given for the measurement location and have been adjusted for instrument error.

BASES (continued)

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

Another set of limits on DNB related parameters is provided in SL 2.1.1, “Reactor Core SLs.” Those limits are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

ACTIONS

A.1

RCS pressure and RCS average temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

The 2-hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

(continued)

BASES

ACTIONS (continued)

B.1

If Required Action A.1 is not 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 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1 *

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12-hour Surveillance Frequency for verifying that the pressurizer pressure is sufficient to ensure the pressure can be restored to a normal operation, steady state condition following load changes and other expected transient operations. The 12-hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.2 *

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12-hour Surveillance Frequency for verifying RCS average temperature is sufficient to ensure the temperature can be restored to a normal operation, steady state condition following load changes and other expected transient operations. The 12-hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.3 *

The 12-hour Surveillance Frequency to verify the RCS total flow rate is performed using the installed flow instrumentation. The 12-hour interval has been shown by operating practice to be sufficient to regularly assess potential degradation and to verify operation within safety analysis assumptions.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.1.4 *

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance once every 18 months allows the installed RCS flow instrumentation to be calibrated and verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

The Frequency of 18 months reflects the importance of verifying flow after a refueling outage when the core has been altered, which may have caused an alteration of flow resistance.

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is not required to be performed until 24 hours after ≥ 90% RTP. This exception is appropriate since the heat balance method requires the plant to be at a minimum of 90% RTP to obtain the stated RCS flow accuracies. The Surveillance shall be performed within 24 hours after reaching 90% RTP.

*Note: The accuracy of the instruments used for monitoring RCS pressure, temperature and flow rate is discussed in this Bases section under LCO.

REFERENCES

1. Watts Bar FSAR, Section 15.0, “Accident Analysis,” Section 15.2, “Condition II - Faults of Moderate Frequency,” and Section 15.3.4, “Complete Loss Of Forced Reactor Coolant Flow.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is moderator temperature coefficient (MTC), LCO 3.1.4, "Moderator Temperature Coefficient (MTC)." In the transient and accident analyses, the MTC is assumed to be in a range from slightly positive to negative, and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil ductility reference temperature when the reactor is critical.

BASES (continued)

APPLICABLE SAFETY ANALYSES

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for hot zero power (HZP) is a process variable that is an initial condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal, RCCA ejection, and main steam line break accidents performed at zero power that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

All low power safety analyses assume initial RCS loop temperatures ≥ the HZP temperature of 557°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 6°F, for critical operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) at a temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

APPLICABILITY

In MODE 1 and MODE 2, with $k_{eff} \geq 1.0$, LCO 3.4.2 is applicable since the reactor can only be critical ($k_{eff} \geq 1.0$) in these MODES.

The special test exception of LCO 3.1.10, "PHYSICS TESTS Exceptions – MODE 2," permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average temperatures to fall below the temperature limit of this LCO.

BASES (continued)

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, 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 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30-minute period. The allowed time is reasonable, based on operating experience, to reach MODE 3 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified at or above 551°F (value does not account for instrument error) every 30 minutes when the T_{avg} - T_{ref} deviation alarm is not reset and any RCS loop T_{avg} < 561°F.

The Note modifies the SR. When any RCS loop average temperature is < 561°F and the T_{avg} - T_{ref} deviation alarm is alarming, RCS loop average temperatures could fall below the LCO requirement without additional warning. The SR to verify RCS loop average temperatures every 30 minutes is frequent enough to prevent the inadvertent violation of the LCO.

REFERENCES

1. Watts Bar FSAR, Section 15.0, "Accident Analysis."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The PTLR contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature (Ref. 1).

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, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 2 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 XI, Appendix G (Ref. 3).

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

(continued)

BASES

BACKGROUND (continued)

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. 4) and Appendix H of 10 CFR 50 (Ref. 5). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 6).

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

The criticality limit curve includes the Reference 2 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature for Criticality."

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. 7), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

BASES (continued)

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, an unanalyzed condition. Reference 8 establishes the methodology for determining the P/T limits. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing; and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

The limits for the rate of change of temperature control and the thermal gradient through the vessel wall are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follow:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

BASES (continued)

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "RCS Minimum Temperature for Criticality"; and Safety Limit 2.1, "Safety Limits," also provide operational restrictions for pressure and temperature and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

Condition A is modified by a Note requiring Required Action A.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. In reduced pressure and temperature conditions, the possibility of propagation with undetected flaws is decreased.

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure < 500 psig within 36 hours.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by stress analysis.

The immediate Completion Time reflects the urgency of initiating action to restore 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 that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the 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 permit assessment and correction for minor deviations within a reasonable time.

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. Appendix "B" to RCS System Description N3-68-4001, "Watts Bar Unit 2 RCS Pressure and Temperature Limits Report."

2. Title 10, Code of Federal Regulations, Part 50, Appendix G, "Fracture Toughness Requirements."

3. ASME Boiler and Pressure Vessel Code, Section XI, Appendix G, "Fracture Toughness Criteria for Protection Against Failure."

4. ASTM E 185-82, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels," July 1982.

5. Title 10, Code of Federal Regulations, Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements."

6. Regulatory Guide 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials," May 1988.

7. ASME Boiler and Pressure Vessel Code, Section XI, Appendix E, "Evaluation of Unanticipated Operating Events."

8. WCAP-14040-A, Revision 4, “Methodology Used to Develop Cold Overpressure Mitigating System Setpoints and RCS Heatup and Cooldown Limit Curves,” May 2004.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops - MODES 1 and 2

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission;

b. Improving the neutron economy by acting as a reflector;

c. Carrying the soluble neutron poison, boric acid;

d. Providing a second barrier against fission product release to the environment; and

e. Removing the heat generated in the fuel due to fission product decay following a unit shutdown.

The reactor coolant is circulated through four loops connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the clad fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Both transient and steady state analyses have been performed to establish the effect of flow on the departure from nucleate boiling (DNB). The transient and accident analyses for the plant have been performed assuming four RCS loops are in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the four pump coastdown, single pump locked rotor, single pump (broken shaft or coastdown), and rod withdrawal events (Ref. 1).

Steady state DNB analysis has been performed for the four RCS loop operation. For four RCS loop operation, the steady state DNB analysis, which generates the pressure and temperature Safety Limit (SL) (i.e., the departure from nucleate boiling ratio (DNBR) limit) assumes a maximum power level of 118% RTP. This is the design overpower condition for four RCS loop operation. The value for the accident analysis setpoint of the nuclear overpower (high flux) trip is 118% and is based on an analysis assumption that bounds possible instrumentation errors. The DNBR limit defines a locus of pressure and temperature points that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

The plant is designed to operate with all RCS loops in operation to maintain DNBR above the SL, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops - MODES 1 and 2 satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, four pumps are required at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG.

BASES (continued)

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

Operation in other MODES is covered by:

LCO 3.4.5, “RCS Loops - MODE 3”;

LCO 3.4.6, “RCS Loops - MODE 4”;

LCO 3.4.7, “RCS Loops - MODE 5, Loops Filled”;

LCO 3.4.8, “RCS Loops - MODE 5, Loops Not Filled”;

LCO 3.9.5, “Residual Heat Removal (RHR) and Coolant Circulation - High Water Level” (MODE 6); and

LCO 3.9.6, “Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level” (MODE 6).

ACTIONS

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging safety systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification every 12 hours that each RCS loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

REFERENCES

1. Watts Bar FSAR, Section 15.0, "Accident Analysis."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loops - MODE 3

BASES

BACKGROUND

In MODE 3, the primary function of the reactor coolant is removal of decay heat and transfer of this heat, via the steam generators (SGs), to the secondary plant fluid. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops, connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The reactor vessel contains the clad fuel. The SGs provide the heat sink. The RCPs circulate the water through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage.

In MODE 3, RCPs are used to provide forced circulation for heat removal during heatup and cooldown. The MODE 3 decay heat removal requirements are low enough that a single RCS loop with one RCP running is sufficient to remove core decay heat. However, two RCS loops are required to be OPERABLE to ensure redundant capability for decay heat removal.

APPLICABLE SAFETY ANALYSES

Whenever the reactor trip breakers (RTBs) are in the closed position and the control rod drive mechanisms (CRDMs) are energized, an inadvertent rod withdrawal from subcritical, resulting in a power excursion, is possible. Such a transient could be caused by a malfunction of the rod control system. In addition, the possibility of a power excursion due to the ejection of an inserted control rod is possible with the breakers closed or open. Such a transient could be caused by the mechanical failure of a CRDM.

Therefore, in MODE 3 with RTBs in the closed position and Rod Control System capable of rod withdrawal, accidental control rod withdrawal from subcritical is postulated and requires at least two RCS loops to be OPERABLE and in operation to ensure that the accident analyses limits are met. For those conditions when the Rod Control System is not capable of rod withdrawal, two RCS loops are required to be OPERABLE, but only one RCS loop is required to be in operation to be consistent with MODE 3 accident analyses.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Failure to provide decay heat removal may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops - MODE 3 satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The purpose of this LCO is to require that at least two RCS loops be OPERABLE. In MODE 3 with the RTBs in the closed position and Rod Control System capable of rod withdrawal, two RCS loops must be in operation. Two RCS loops are required to be in operation in MODE 3 with RTBs closed and Rod Control System capable of rod withdrawal due to the postulation of a power excursion because of an inadvertent control rod withdrawal. The required number of RCS loops in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents.

With the RTBs in the open position, or the CRDMs de-energized, the Rod Control System is not capable of rod withdrawal; therefore, only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is required to be OPERABLE to ensure adequate decay heat removal capability.

The Note permits all RCPs to be de-energized for $\leq$ 1 hour per 8 hour period. The purpose of the Note is to perform tests that are designed to validate various accident analyses values. One of these tests is validation of the pump coastdown curve used as input to a number of accident analyses including a loss of flow accident. This test is generally performed in MODE 3 during the initial startup testing program, and as such should only be performed once.

If, however, changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values of the coastdown curve must be revalidated by conducting the test again. The 1 hour time period specified is adequate to perform the desired tests, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

(continued)

BASES

LCO (continued)

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, thereby maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG, which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with RTBs in the closed position. The least stringent condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the RTBs open.

Operation in other MODES is covered by:

LCO 3.4.4, “RCS Loops - MODES 1 and 2”;

LCO 3.4.6, “RCS Loops - MODE 4”;

LCO 3.4.7, “RCS Loops - MODE 5, Loops Filled”;

LCO 3.4.8, “RCS Loops - MODE 5, Loops Not Filled”;

LCO 3.9.5, “Residual Heat Removal (RHR) and Coolant Circulation - High Water Level” (MODE 6); and

LCO 3.9.6, “Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level” (MODE 6).

BASES (continued)

ACTIONS

A.1

If one required RCS loop is inoperable, redundancy for heat removal is lost. The Required Action is restoration of the required RCS loop to OPERABLE status within the Completion Time of 72 hours. This time allowance is a justified period to be without the redundant, non-operating loop because a single loop in operation has a heat transfer capability greater than that needed to remove the decay heat produced in the reactor core and because of the low probability of a failure in the remaining loop occurring during this period.

B.1

If restoration is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

If the required RCS loop is not in operation, and the RTBs are closed and Rod Control System capable of rod withdrawal, the Required Action is either to restore the required RCS loop to operation or to de-energize all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets. When the RTBs are in the closed position and Rod Control System capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the RTBs must be opened. The Completion Times of 1 hour to restore the required RCS loop to operation or de-energize all CRDMs is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

(continued)

BASES (continued)

ACTIONS (continued)

D.1, D.2, and D.3

If all RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets. All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification includes flow rate, temperature, and pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 6 % (value does not account for instrument error) for required RCS loops. If the SG secondary side narrow range water level is less than 6 %, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs.

REFERENCES None

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops - MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers (HXs). The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops connected in parallel to the reactor vessel, each loop containing an SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and to prevent boric acid stratification.

In MODE 4, with the reactor trip breakers open and the rods not capable of withdrawal, either RCPs or RHR loops can be used to provide forced circulation. The intent in this case is to provide forced flow from at least one RCP or one RHR loop for decay heat removal and transport. The flow provided by one RCP loop or RHR loop is adequate for decay heat removal. The other intent is to require that two paths be available to provide redundancy for decay heat removal.

In MODE 4, with the reactor trip breakers closed and the rods capable of withdrawal, two RCPs must be OPERABLE and in operation to provide forced circulation.

During a normal shutdown, decay heat removal is via the RCS loops until sometime after the unit has been cooled down to RHR entry conditions (T_{cold} < 350ºF). Therefore, as LCO 3.4.6 becomes Applicable (entry into MODE 4) the RCS loops are still OPERABLE. Transitioning decay heat removal to the RHR System will place high heat loads on the RHR System, Component Cooling System (CCS), and the Essential Raw Cooling Water System (ERCW). Residual and decay heat from the RCS is transferred to CCS via the RHR HX. Heat from the CCS is transferred to the ERCW System via the CCS HXs. The CCS and ERCW systems are common between the two operating units.

BASES (continued)

APPLICABLE SAFETY ANALYSES

In MODE 4, with the reactor trip breakers open and the rods not capable of withdrawal, RCS circulation is considered in determination of the time available for mitigation of the accidental boron dilution event. The RCS and RHR loops provide this circulation.

Whenever the reactor trip breakers (RTBs) are in the closed position and the control rod drive mechanisms (CRDMs) are energized, an inadvertent rod withdrawal from subcritical, resulting in a power excursion, is possible. Such a transient could be caused by a malfunction of the rod control system. In addition, the possibility of a power excursion due to the ejection of an inserted control rod is possible with the breakers closed or open. Such a transient could be caused by the mechanical failure of a CRDM.

Therefore, in MODE 4 with RTBs in the closed position and Rod Control System capable of rod withdrawal, accidental control rod withdrawal from subcritical is postulated and requires at least two RCS loops to be OPERABLE and in operation to ensure that the accident analyses limits are met. For those conditions when the Rod Control System is not capable of rod withdrawal, any combination of two RCS or RHR loops are required to be OPERABLE, but only one loop is required to be in operation to meet decay heat removal requirements, except during the initial seven hours after unit shutdown, when the decay and latent heat load may exceed the heat removal capability of one RHR loop in operation.

During the initial seven hours after reactor shutdown, the heat loads are at sufficiently high levels that the requirement of LCO 3.4.6 for one RHR loop in operation may not be sufficient to mitigate a design basis accident on Unit 1 and preclude a heatup of Unit 2.

To assure that there would be adequate heat removal capability under all postulated conditions during the initial seven hours after unit shutdown, reliance on heat removal via RCS loops is required. After a unit has been shutdown for greater than seven hours, a single RHR loop in operation provides adequate heat removal capability.

RCS Loops - MODE 4 have been identified in 10 CFR 50.36 (c)(2)(ii) as important contributors to risk reduction.

BASES (continued)

LCO

The purpose of this LCO is to require that at least two loops be OPERABLE. In MODE 4 with the RTBs in the closed position and Rod Control System capable of rod withdrawal, two RCS loops must be OPERABLE and in operation. Two RCS loops are required to be in operation in MODE 4 with RTBs closed and Rod Control System capable of rod withdrawal due to the postulation of a power excursion because of an inadvertent control rod withdrawal. The required number of RCS loops in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents.

With the RTBs in the open position, or the CRDMs de-energized, the Rod Control System is not capable of rod withdrawal; therefore, only one loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. In this case, the LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS loops and RHR loops. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

Note 1 requires that the secondary side water temperature of each SG be $\leq$ 50°F above each of the RCS cold leg temperatures before the start of an RCP with any RCS cold leg temperature less than or equal to the COMS arming temperature as specified in the PTLR. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 2 requires two RCS loops to be OPERABLE during the initial seven hours after entry into MODE 3 from MODE 1 or MODE 2 until decay heat and latent heat are within the capacity of the RHR System.

Note 3 precludes entry into MODE 5 during the initial seven hours after entry into MODE 3 from MODE 2 or MODE 1. This ensures that heat removal capability via RCS loops is retained until decay heat and latent heat are within the capacity of the RHR System.

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG, which has the minimum water level specified in SR 3.4.6.3.

Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

BASES (continued)

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of either RCS or RHR provides sufficient circulation for these purposes. However, two loops consisting of any combination of RCS and RHR loops are required to be OPERABLE to meet single failure considerations.

Operation in other MODES is covered by:

LCO 3.4.4, “RCS Loops - MODES 1 and 2”;

LCO 3.4.5, “RCS Loops - MODE 3”;

LCO 3.4.7, “RCS Loops - MODE 5, Loops Filled”;

LCO 3.4.8, “RCS Loops - MODE 5, Loops Not Filled”;

LCO 3.9.5, “Residual Heat Removal (RHR) and Coolant Circulation - High Water Level” (MODE 6); and

LCO 3.9.6, “Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level” (MODE 6).

ACTIONS

A.1

If only one RCS loop is OPERABLE and both RHR loops are inoperable, redundancy for heat removal is lost, and action must be initiated to restore a second RCS or RHR loop to OPERABLE status. If only one RCS loop is OPERABLE and it has been less than seven hours since the unit has entered MODE 3 from MODE 1 or MODE 2, redundancy has been lost and action must be initiated to restore a second RCS loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1

If one required RHR loop is OPERABLE and in operation and there are no RCS loops OPERABLE, an inoperable RCS or RHR loop must be restored to OPERABLE status to provide a redundant means for decay heat removal.

If the parameters that are outside the limits cannot be restored, the plant must be brought to MODE 5 within 24 hours. Bringing the plant to MODE 5 is a conservative action with regard to decay heat removal. With only one required RHR loop OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the remaining RHR loop, it would be safer to initiate that loss from MODE 5 (less than or equal to 200°F) rather than MODE 4 (200 to 350°F). The Completion Time of

(continued)

BASES

ACTIONS

B.1 (continued)

24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

C.1 and C.2

If one required RCS loop is not in operation, and the RTBs are closed and Rod Control System capable of rod withdrawal, the Required Action is either to restore the required RCS loop to operation or to de-energize all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets. When the RTBs are in the closed position and Rod Control System capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the RTBs must be opened. The Completion Times of 1 hour to restore the required RCS loop to operation or de-energize all CRDMs is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

D.1, D.2 and D.3

If no loop is OPERABLE or in operation, all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets. All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one required RCS or RHR loop to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and the margin to criticality must not be reduced in this type of operation. Opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that two RCS loops are in operation when the rod control system is capable of rod withdrawal. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS and RHR loop performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.6.2

This SR requires verification every 12 hours that one required RCS or RHR loop is in operation when the rod control system is not capable of rod withdrawal. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS and RHR loop performance.

SR 3.4.6.3

SR 3.4.6.3 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is greater than or equal to 32% (value does not account for instrument error, Ref. 1). If the SG secondary side narrow range water level is less than 32%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12-hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.4

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES None

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops - MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining two SGs with secondary side water levels greater than or equal to 6% narrow range to provide an alternate method for decay heat removal.

BASES (continued)

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops - MODE 5 (Loops Filled) have been identified in 10 CFR 50.36(c)(2)(ii) as important contributors to risk reduction.

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or two SGs with secondary side water level greater than or equal to 6% narrow range. One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is two SGs with their secondary side water levels greater than or equal to 6% narrow range. Should the operating RHR loop fail, the SGs could be used to remove the decay heat.

Note 1 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when such testing is safe and possible.

Note 2 requires that the secondary side water temperature of each SG be $\leq$ 50°F above each of the RCS cold leg temperatures before the start of a reactor coolant pump (RCP) with an RCS cold leg temperature less than the COMS arming temperature specified in the PTLR. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 3 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An SG can perform as a heat sink when it has an adequate water level and is OPERABLE.

BASES (continued)

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the secondary side water level of at least two SGs is required to be ≥ 6% narrow range.

Operation in other MODES is covered by:

LCO 3.4.4, “RCS Loops - MODES 1 and 2”;

LCO 3.4.5, “RCS Loops - MODE 3”;

LCO 3.4.6, “RCS Loops - MODE 4”;

LCO 3.4.8, “RCS Loops - MODE 5, Loops Not Filled”;

LCO 3.9.5, “Residual Heat Removal (RHR) and Coolant Circulation - High Water Level” (MODE 6); and

LCO 3.9.6, “Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level” (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SGs have secondary side water levels < 6% narrow range, redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water levels. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side narrow range water levels are greater than or equal to 6% (value does not account for instrument error) narrow range ensures an alternate decay heat removal method in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12-hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side water level is greater than or equal to 6% narrow range in at least two SGs, this Surveillance is not needed. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES None

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops - MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat generated in the fuel, and the transfer of this heat to the component cooling water via the residual heat removal (RHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with loops not filled, only RHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR pump for decay heat removal and transport and to require that two paths be available to provide redundancy for heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation. The flow provided by one RHR loop is adequate for heat removal and for boron mixing.

RCS loops in MODE 5 (loops not filled) have been identified in 10 CFR 50.36(c)(2)(ii) as important contributors to risk reduction.

LCO

The purpose of this LCO is to require that at least two RHR loops be OPERABLE and one of these loops be in operation. An OPERABLE loop is one that has the capability of transferring heat from the reactor coolant at a controlled rate. Heat cannot be removed via the RHR System unless forced flow is used. A minimum of one running RHR pump meets the LCO requirement for one loop in operation. An additional RHR loop is required to be OPERABLE to meet single failure considerations.

(continued)

BASES

LCO (continued)

Note 1 permits all RHR pumps to be de-energized for ≤ 15 minutes when switching from one loop to another. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and core outlet temperature is maintained > 10°F below saturation temperature. The Note prohibits boron dilution or draining operations when RHR forced flow is stopped.

Note 2 allows one RHR loop to be inoperable for a period of ≤ 2 hours, provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during the only time when these tests are safe and possible.

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.

APPLICABILITY

In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System.

Operation in other MODES is covered by:

LCO 3.4.4, “RCS Loops - MODES 1 and 2;”

LCO 3.4.5, “RCS Loops - MODE 3;”

LCO 3.4.6, “RCS Loops - MODE 4;”

LCO 3.4.7, “RCS Loops - MODE 5, Loops Filled;”

LCO 3.9.5, “Residual Heat Removal (RHR) and Coolant Circulation - High Water Level” (MODE 6); and

LCO 3.9.6, “Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level” (MODE 6).

BASES (continued)

ACTIONS

A.1

If only one RHR loop is OPERABLE and in operation, redundancy for RHR is lost. Action must be initiated to restore a second loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no required RHR loops are OPERABLE or in operation, except during conditions permitted by Note 1, all operations involving a reduction of RCS boron concentration must be suspended and action must be initiated immediately to restore an RHR loop to OPERABLE status and operation. Boron dilution requires forced circulation for uniform dilution, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification every 12 hours that one loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.8.2

Verification that the required number of pumps are OPERABLE ensures that additional pumps can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pumps. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES None

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation, and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level, the required heaters, and their controls. Pressurizer safety valves and pressurizer power operated relief valves are addressed by LCO 3.4.10, “Pressurizer Safety Valves,” and LCO 3.4.11, “Pressurizer Power Operated Relief Valves (PORVs),” respectively.

The intent of the LCO is to ensure that a steam bubble exists in the pressurizer prior to power operation to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions. Relatively small amounts of noncondensible gases can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control.

Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant. Unless adequate heater capacity is available, the hot, high pressure condition cannot be maintained indefinitely and still provide the required subcooling margin in the primary system. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of single phase natural circulation and decreased capability to remove core decay heat.

BASES (continued)

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present.

Safety analyses presented in the FSAR (Ref. 1) do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure.

The maximum pressurizer water level limit satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii). Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

LCO

The LCO requirement for the pressurizer to be OPERABLE with a water volume ≤ 1656 cubic feet, which is equivalent to 92%, ensures that a steam bubble exists. Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires two groups of OPERABLE pressurizer heaters, each with a capacity ≥ 150 kW. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The design value of 150 kW per group is exceeded by the use of fifteen heaters in a group rated at 23.1 kW each. The amount needed to maintain pressure is dependent on the heat losses.

BASES (continued)

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

ACTIONS

A.1 and A.2

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions. Normally the plant will trip in this event since the upper limit of this LCO is the same as the Pressurizer Water Level - High Trip.

If the pressurizer water level is not within the limit, action must be taken to restore the plant to operation within the bounds of the safety analyses. To achieve this status, the plant must be brought to MODE 3, with the reactor trip breakers open, within 6 hours and to MODE 4 within 12 hours. This takes the plant out of the applicable MODES and restores the plant to operation within the bounds of the safety analyses.

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.

B.1

If one required group of pressurizer heaters is inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering the anticipation that a demand caused by loss of offsite power would be unlikely in this period.

(continued)

BASES (continued)

ACTIONS (continued)

C.1 and C.2

If one group of pressurizer heaters is inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, 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 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper level limit of ≤92% (value does not account for instrument error) to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Frequency of 12 hours corresponds to verifying the parameter each shift. The 12-hour interval has been shown by operating practice to be sufficient to regularly assess level for any deviation and verify that operation is within safety analyses assumptions. Alarms are also available for early detection of abnormal level indications.

SR 3.4.9.2

The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design rating. This may be done by testing the power supply output and by performing an electrical check on heater element continuity and resistance. The Frequency of 92 days is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

REFERENCES

1. Watts Bar FSAR, Section 15.0, “Accident Analyses.”

2. NUREG-0737, “Clarification of TMI Action Plan Requirements,” November 1980.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed pop type, spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig (2750 psia), which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The relief capacity for each valve, 420,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves or increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 4 with any RCS cold leg temperature less than or equal to the COMS arming temperature specified in the PTLR, MODE 5, and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, “Cold Overpressure Mitigation System (COMS).”

The upper and lower pressure limits are based on a ± 3% tolerance. The lift setting is for the ambient conditions associated with MODES 1, 2, 3, and MODE 4 with all RCS cold leg temperatures greater than the COMS arming temperature specified in the PTLR. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure.

(continued)

BASES

BACKGROUND (continued)

The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

APPLICABLE SAFETY ANALYSES

All accident and safety analyses in the FSAR (Ref. 2) that require safety valve actuation assume operation of three pressurizer safety valves to limit increases in RCS pressure. The overpressure protection analysis (Ref. 3) is also based on operation of three safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal from full power;

b. Loss of reactor coolant flow;

c. Loss of external electrical load;

d. Loss of normal feedwater;

e. Loss of all AC power to station auxiliaries;

f. Locked rotor; and

g. Feedwater line break.

Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation is required in events c, d, e, f, and g (above) to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions.

Pressurizer safety valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The three pressurizer safety valves are set to open at the RCS design pressure (2485 psig), and within the specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits are based on a ± 3% tolerance. The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and MODE 4 with all RCS cold leg temperatures greater than the COMS arming temperature specified in the PTLR, OPERABILITY of three valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODES 3 and 4 are conservatively included, although the listed accidents may not require the safety valves for protection.

The LCO is not applicable in MODE 4 when all RCS cold leg temperatures are less than or equal to the COMS arming temperature as specified in the PTLR, in MODE 5, or in MODE 6 (with the reactor vessel head on) because COMS is provided. Overpressure protection is not required in MODE 6 with reactor vessel head detensioned.

The Note allows entry into MODE 3 and MODE 4 with all RCS cold leg temperatures greater than the COMS arming temperature specified in the PTLR, with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 54-hour exception is based on 18 hour outage time for each of the three valves. The 18 hour period is derived from operating experience that hot testing can be performed in this timeframe.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS Overpressure Protection System. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two or more pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with any RCS cold leg temperature less than or equal to the COMS arming temperature specified in the PTLR within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. With any RCS cold leg temperatures at or below the COMS arming temperature as specified in the PTLR, overpressure protection is provided by the COMS System. The change from MODE 1, 2, or 3 to MODE 4 with any RCS cold leg temperature less than or equal to the COMS arming temperature specified in the PTLR reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by three pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of the ASME OM Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is ± 3% for OPERABILITY, however, the valves are reset to ± 1% during the surveillance to allow for drift.

REFERENCES

1. ASME Boiler and Pressure Vessel Code, Section III, NB 7000, 1971 Edition through Summer 1973.

2. Watts Bar FSAR, Section 15.0, “Accident Analyses.”

3. WCAP-7769, Rev. 1, “Topical Report on Overpressure Protection for Westinghouse Pressurized Water Reactors,” June 1972.

4. American Society of Mechanical Engineers (ASME) OM Code, “Code for Operation and Maintenance of Nuclear Power Plants.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and PORVs. The PORVs are pilot-operated solenoid valves that are controlled to open at a specific set pressure when the pressurizer pressure increases and close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

Block valves, which are normally open, are located between the pressurizer and the PORVs. The block valves are used to isolate the PORVs in case of excessive leakage or a stuck open PORV. Block valve closure is accomplished manually using controls in the control room. A stuck open PORV is, in effect, a small break loss of coolant accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permit performance of surveillances on the valves during power operation.

The PORVs may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

The PORVs, their block valves, and their controls are powered from the vital buses that normally receive power from offsite power sources, but are also capable of being powered from emergency power sources in the event of a loss of offsite power. Two PORVs and their associated block valves are powered from two separate safety trains (Ref. 1).

The plant has two PORVs, each having a relief capacity of 210,000 lb/hr at 2485 psig. The functional design of the PORVs is based on maintaining pressure below the Pressurizer Pressure - High reactor trip setpoint following a step reduction of 50% of full load with steam dump. In addition, the PORVs minimize challenges to the pressurizer safety valves and also may be used for low temperature overpressure protection (LTOP). See LCO 3.4.12, “Cold Overpressure Mitigation System (COMS).”

BASES (continued)

APPLICABLE SAFETY ANALYSES

Plant operators employ the PORVs to depressurize the RCS in response to certain plant transients if normal pressurizer spray is not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the affected steam generator.

The PORVs are modeled in safety analyses for events that result in increasing RCS pressure for which departure from nucleate boiling ratio (DNBR), pressurizer filling, or reactor coolant saturation criteria are critical (Ref. 2). By assuming PORV actuation, the primary pressure remains below the high pressurizer pressure trip setpoint; thus, the DNBR calculation is more conservative. As such, this actuation is not required to mitigate these events, and PORV automatic operation is, therefore, not an assumed safety function.

Pressurizer PORVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires the PORVs and their associated block valves to be OPERABLE for manual operation to mitigate the effects associated with an SGTR.

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. An OPERABLE block valve may be either open and energized with the capability to be closed, or closed and energized with the capability to be opened, since the required safety function is accomplished by manual operation, the block valves may be OPERABLE when closed to isolate the flow path of an inoperable PORV that is capable of being manually cycled (e.g., as in the case of excessive PORV leakage). Similarly, isolation of an OPERABLE PORV does not render that PORV or block valve inoperable provided the relief function remains available with manual action.

An OPERABLE PORV is required to be capable of manually opening and closing and not experiencing excessive seat leakage. Excessive seat leakage although not associated with a specific acceptance criteria, exists when conditions dictate closure of block valve to limit leakage.

Satisfying the LCO helps minimize challenges to fission product barriers.

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, the PORV and its block valve are required to be OPERABLE to limit the potential for a small break LOCA through the flow path. The most likely cause for a PORV small break LOCA is a result of a pressure increase transient that causes the PORV to open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the RCS pressure to increase to the PORV opening setpoint. The most rapid increases will occur at the higher operating power and pressure conditions of MODES 1 and 2. The PORVs are also required to be OPERABLE in MODES 1, 2, and 3 for manual actuation to mitigate a steam generator tube rupture event.

Pressure increases are less prominent in MODE 3 because the core input energy is reduced, but the RCS pressure is high. Therefore, the LCO is applicable in MODES 1, 2, and 3. The LCO is not applicable in MODE 4, 5, and 6 with the reactor vessel head in place when both pressure and core energy are decreased and the pressure surges become much less significant. LCO 3.4.12 addresses the PORV requirements in these MODES.

ACTIONS

A Note has been added to clarify that all pressurizer PORVs are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis).

A.1

PORVs may be inoperable and capable of being manually cycled (e.g., due to excessive seat leakage). In this condition, either the PORV must be restored or the flow path isolated within 1 hour. The associated block valve is required to be closed, but power must be maintained to the associated block valve, since removal of power would render the block valve inoperable. This permits operation of the plant until the next refueling outage (MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem condition.

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

(continued)

BASES

ACTIONS (continued)

B.1, B.2, and B.3

If one PORV is inoperable and not capable of being manually cycled, it must be either restored or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Times of 1 hour are reasonable, based on challenges to the PORVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time. Because there is at least one PORV that remains OPERABLE, an additional 72 hours is provided to restore the inoperable PORV to OPERABLE status. If the PORV cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

C.1 and C.2

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the Completion Time of 1 hour or place the associated PORV in manual control. The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation. Because at least one PORV remains OPERABLE, the operator is permitted a Completion Time of 72 hours to restore the inoperable block valve to OPERABLE status. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B, since the PORVs may not be capable of mitigating an event if the inoperable block valve is not full open. If the block valve is restored within the Completion Time of 72 hours, the PORV may be restored to automatic operation. If it cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the Required Action of Condition A, B, or C is not met, then 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 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, automatic PORV OPERABILITY may be required. See LCO 3.4.12.

E.1, E.2, E.3, and E.4

If both PORVs are inoperable and not capable of being manually cycled, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation. If no PORVs are restored within the Completion Time, then 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 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, automatic PORV OPERABILITY may be required. See LCO 3.4.12.

F.1 and F.2

If both block valves are inoperable, it is necessary to either restore the block valves within the Completion Time of 1 hour, or place the associated PORVs in manual control and restore at least one block valve within 2 hours. The Completion Times are reasonable, based on the small potential for challenges to the system during this time and provide the operator time to correct the situation.

G.1 and G.2

If the Required Actions of Condition F are not met, then 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 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, automatic PORV OPERABILITY may be required. See LCO 3.4.12.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be opened and closed if needed. The basis for the Frequency of 92 days is the ASME OM Code (Ref. 3). If the block valve is closed to isolate a PORV that is capable of being manually cycled, the OPERABILITY of the block valve is of importance, because opening the block valve is necessary to permit the PORV to be used for manual control of reactor pressure. If the block valve is closed to isolate an inoperable PORV that is incapable of being manually cycled, the maximum Completion Time to restore the PORV and open the block valve is 72 hours, which is well within the allowable limits (25%) to extend the block valve Frequency of 92 days. Furthermore, these test requirements would be completed by the reopening of a recently closed block valve upon restoration of the PORV to OPERABLE status.

The Note modifies this SR by stating that it is not required to be met with the block valve closed, in accordance with the Required Action of this LCO.

SR 3.4.11.2

SR 3.4.11.2 requires a complete cycle of each PORV. Operating a PORV through one complete cycle ensures that the PORV can be manually actuated for mitigation of an SGTR. The Frequency of 18 months is based on a typical refueling cycle and industry accepted practice.

REFERENCES

1. Regulatory Guide 1.32, “Criteria for Safety Related Electric Power Systems for Nuclear Power Plants,” U.S. Nuclear Regulatory Commission, February 1977.

2. Watts Bar FSAR, Section 15.2, “Condition II - Faults of Moderate Frequency.”

3. American Society of Mechanical Engineers (ASME) OM Code, “Code for Operation and Maintenance of Nuclear Power Plants.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Cold Overpressure Mitigation System (COMS)

BASES

BACKGROUND

The COMS controls RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The PTLR provides the maximum allowable actuation logic setpoints for the power operated relief valves (PORVs) and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the COMS MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, “RCS Pressure and Temperature (P/T) Limits,” requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

This LCO provides RCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability requires all safety injection pumps and all but one charging pump incapable of injection into the RCS and isolating the accumulators. The pressure relief capacity requires either two redundant RCS relief valves or a depressurized RCS and an RCS vent of sufficient size. One RCS relief valve or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

(continued)

BACKGROUND (continued)

With minimum coolant input capability, the ability to provide core coolant addition is restricted. The LCO does not require the makeup control system deactivated or the safety injection (SI) actuation circuits blocked. Due to the lower pressures in the COMS MODES and the expected core decay heat levels, the makeup system can provide adequate flow via the makeup control valve. If conditions require the use of more than one charging pump or safety injection pump for makeup in the event of loss of inventory, then pumps can be made available through manual actions.

The COMS for pressure relief consists of two PORVs with reduced lift settings, or one PORV and the Residual Heat Removal (RHR) suction relief valve, or a depressurized RCS and an RCS vent of sufficient size. Two RCS relief valves are required for redundancy. One RCS relief valve has adequate relieving capability to keep from overpressurization for the required coolant input capability.

PORV Requirements

As designed for the COMS, each PORV is signaled to open if the RCS pressure approaches a limit determined by the COMS actuation logic. The COMS actuation logic monitors both RCS temperature and RCS pressure and determines when a condition not acceptable in the PTLR limits is approached. The wide range RCS temperature indications are auctioneered to select the lowest temperature signal.

The lowest temperature signal is processed through a function generator that calculates a pressure limit for that temperature. The calculated pressure limit is then compared with the indicated RCS pressure from a wide range pressure channel. If the indicated pressure meets or exceeds the calculated value, a PORV is signaled to open.

The PTLR presents the PORV setpoints for COMS. The setpoints are normally staggered so only one valve opens during a low temperature overpressure transient. Having the setpoints of both valves within the limits in the PTLR ensures that the Reference 1 limits will not be exceeded in any analyzed event.

When a PORV is opened in an increasing pressure transient, the release of coolant will cause the pressure increase to slow and reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

(continued)

BASES

BACKGROUND (continued)

RHR Suction Relief Valve Requirements

During COMS MODES, the RHR System is operated for decay heat removal and low pressure letdown control. Therefore, the RHR suction isolation valves are open in the piping from the RCS hot leg to the inlet header of the RHR pumps. While these valves are open, the RHR suction relief valve is exposed to the RCS and is able to relieve pressure transients in the RCS.

The RHR suction isolation valves must be open to make the RHR suction relief valve OPERABLE for RCS overpressure mitigation. Autoclosure interlocks are not permitted to cause the RHR suction isolation valves to close. The RHR suction relief valve is a spring loaded, bellows type water relief valve with pressure tolerances and accumulation limits established by Section III of the American Society of Mechanical Engineers (ASME) Code (Ref. 3) for Class 2 relief valves.

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting COMS mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

For an RCS vent to meet the flow capacity requirement, it requires removing a pressurizer safety valve, removing a PORV, and disabling its block valve in the open position, or opening the pressurizer manway. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 4) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, 3, and MODE 4 with all RCS cold leg temperatures greater than the COMS arming temperature specified in the PTLR, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. Below the COMS arming temperature specified in the PTLR, overpressure prevention falls to two OPERABLE RCS relief valves or to a depressurized RCS and a sufficient sized RCS vent. Each of these means has a limited overpressure relief capability.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the PTLR curves are revised, the COMS must be re-evaluated to ensure its functional requirements can still be met using the RCS relief valve method or the depressurized and vented RCS condition.

The PTLR contains the acceptance limits that define the COMS requirements. Any change to the RCS must be evaluated against the Reference 8 analyses to determine the impact of the change on the COMS acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

Mass Input Type Transients

a. Inadvertent safety injection; or

b. Charging/letdown flow mismatch.

Heat Input Type Transients

a. Inadvertent actuation of pressurizer heaters;

b. Loss of RHR cooling; or

c. Reactor coolant pump (RCP) startup with temperature asymmetry within the RCS or between the RCS and steam generators.

The following are required during the COMS MODES to ensure that mass and heat input transients do not occur, which either of the COMS overpressure protection means cannot handle:

a. Rendering all safety injection pumps and all but one charging pump incapable of injection;

b. Deactivating the accumulator discharge isolation valves in their closed positions; and

c. Disallowing start of an RCP if secondary temperature is more than 50°F above primary temperature in any one loop. LCO 3.4.6, “RCS Loops - MODE 4,” and LCO 3.4.7, “RCS Loops - MODE 5, Loops Filled,” provide this protection.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

The Reference 8 analyses demonstrate that either one RCS relief valve or the depressurized RCS and RCS vent can maintain RCS pressure below limits when no safety injection pumps and only one centrifugal charging pump is actuated. Thus, the LCO allows only one charging pump OPERABLE during the COMS MODES. Since neither one RCS relief valve nor the RCS vent can handle the pressure transient induced from accumulator injection, when RCS temperature is low, the LCO also requires the accumulators be isolated when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

The isolated accumulators must have their discharge valves closed and the valve power supply breakers fixed in their open positions. Fracture mechanics analyses established the temperature of COMS Applicability as specified in the PTLR.

The consequences of a small break loss of coolant accident (LOCA) in COMS MODE 4 conform to 10 CFR 50.46 and 10 CFR 50, Appendix K (Refs. 5 and 6) requirements by having a maximum of one charging pump OPERABLE and SI actuation enabled.

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the limit shown in the PTLR. The setpoints are derived by analyses that model the performance of the COMS, assuming the mass injection COMS transient of no safety injection pumps and only one centrifugal charging pump injecting into the RCS and the heat injection COMS transient of starting a RCP with the RCS 50°F colder than the secondary side. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensures the Reference 1 P/T limits will be met.

The PORV setpoints in the PTLR will be updated when the revised P/T limits conflict with the COMS analysis limits. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron irradiation. Revised limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3, “RCS Pressure and Temperature (P/T) Limits,” discuss these examinations.

The PORVs are considered active components. Thus, the failure of one PORV is assumed to represent the worst case, single active failure.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

RHR Suction Relief Valve Performance

The RHR suction relief valve does not have variable pressure and temperature lift setpoints like the PORVs. Analyses must show that the RHR suction relief valve with a setpoint at or between 436.5 psig and 463.5 psig will pass flow greater than that required for the limiting COMS transient while maintaining RCS pressure less than the P/T limit curve. Assuming all relief flow requirements during the limiting COMS event, the RHR suction relief valve will maintain RCS pressure to within the valve rated lift setpoint, plus an accumulation ≤ 3% of the rated lift setpoint.

The RHR suction relief valve inclusion and location within the RHR System does not allow it to meet single failure criteria when spurious RHR suction isolation valve closure is postulated. Also, as the RCS P/T limits are decreased to reflect the loss of toughness in the reactor vessel materials due to neutron embrittlement, the RHR suction relief valves must be analyzed to still accommodate the design basis transients for COMS.

The RHR suction relief valve is considered an active component. Thus, the failure of this valve is assumed to represent the worst case single active failure.

RCS Vent Performance

With the RCS depressurized, analyses show a vent capable of relieving > 475 gpm water flow is capable of mitigating the allowed COMS overpressure transient. The capacity of 475 gpm is greater than the flow of the limiting transient for the COMS configuration, with one centrifugal charging pump OPERABLE, maintaining RCS pressure less than the maximum pressure on the P/T limit curve.

Three vent flow paths have been identified in the RCS which could serve as pressure release (vent) paths. With one safety or PORV removed, the open line could serve as one vent path. The pressurizer manway could serve as an alternative vent path with the manway cover removed. These flow paths are capable of discharging 475 gpm at low pressure in the RCS. Thus, any one of the openings can be used for relieving the pressure to prevent violating the P/T limits.

The RCS vent size will be re-evaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance. The RCS vent is passive and is not subject to active failure.

The COMS satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

This LCO requires that the COMS is OPERABLE. The COMS is OPERABLE when the minimum coolant input and pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires no safety injection pumps and a maximum of one charging pump be capable of injecting into the RCS, and all accumulator discharge isolation valves be closed and immobilized when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

The LCO is modified by two Notes. Note 1 allows two charging pumps to be made capable of injecting for less than or equal to 1 hour during pump swap operations. One hour provides sufficient time to safely complete the actual transfer and to complete the administrative controls and surveillance requirements associated with the swap. The intent is to minimize the actual time that more than one charging pump is physically capable of injection.

Note 2 states that accumulator isolation is only required when the accumulator pressure is more than or at the maximum RCS pressure for the existing temperature, as allowed by the P/T limit curves. This Note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions.

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two RCS relief valves, as follows:

   1. Two OPERABLE PORVs; or

      A PORV is OPERABLE for COMS when its block valve is open, its lift setpoint is set to the limit required by the PTLR and testing proves its ability to open at this setpoint, and motive power is available to the valve and its control circuit.

   2. One OPERABLE PORV and the OPERABLE RHR suction relief valve; or

      An RHR suction relief valve is OPERABLE for COMS when both RHR suction isolation valves are open, its setpoint is at or between 436.5 psig and 463.5 psig, and testing has proven its ability to open at this setpoint.

(continued)

BASES (continued)

LCO (continued)

b. A depressurized RCS and an RCS vent.

An RCS vent is OPERABLE when capable of relieving > 475 gpm water flow.

Each of these methods of overpressure prevention is capable of mitigating the limiting COMS transient.

APPLICABILITY

This LCO is applicable in MODE 4 with any RCS cold leg temperature less than or equal to the COMS arming temperature specified in the PTLR, MODE 5, and MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above the COMS arming temperature specified in the PTLR. When the reactor vessel head is off, overpressurization cannot occur.

LCO 3.4.3 provides the operational P/T limits for all MODES.
LCO 3.4.10, “Pressurizer Safety Valves,” requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3 and MODE 4 with all RCS cold leg temperatures greater than the COMS arming temperature specified in the PTLR.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time allows operator action to mitigate the event.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable COMS. There is an increased risk associated with entering MODE 4 from MODE 5 with COMS inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1 and B.1

With two or more charging pumps or any safety injection pumps capable of injecting into the RCS, RCS overpressurization is possible.

To immediately initiate action to restore restricted coolant input capability to the RCS reflects the urgency of removing the RCS from this condition.

(continued)

ACTIONS (continued)

C.1, D.1, and D.2

An unisolated accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If isolation is needed and cannot be accomplished in 1 hour, Required Action D.1 and Required Action D.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature to greater than the COMS arming temperature specified in the PTLR, an accumulator discharge cannot exceed the COMS limits if the accumulators are fully injected.

Depressurizing the accumulators below the COMS limit from the PTLR also gives this protection.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring COMS is not likely in the allowed times.

E.1

In MODE 4 with one required RCS relief valve inoperable, the RCS relief valve must be restored to OPERABLE status within a Completion Time of 7 days. Two RCS relief valves are required to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time considers the facts that only one of the RCS relief valves is required to mitigate an overpressure transient and that the likelihood of an active failure of the remaining valve path during this time period is very low.

F.1

The consequences of operational events that will overpressurize the RCS are more severe at lower temperature (Ref. 7). Thus, with one of the two RCS relief valves inoperable in MODE 5 or in MODE 6 with the head on, the Completion Time to restore two valves to OPERABLE status is 24 hours.

The Completion Time represents a reasonable time to investigate and repair several types of relief valve failures without exposure to a lengthy period with only one OPERABLE RCS relief valve to protect against overpressure events.

(continued)

BASES

ACTIONS (continued)

G.1

The RCS must be depressurized and a vent must be established within 8 hours when:

a. Both required RCS relief valves are inoperable; or

b. A Required Action and associated Completion Time of Condition A, B, D, E or F is not met; or

c. The COMS is inoperable for any reason other than Condition A, B, C, D, E or F.

This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

The Completion Time considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, no safety injection pumps and all but one charging pump are verified incapable of injecting into the RCS and the accumulator discharge isolation valves are verified closed and locked out.

The safety injection pumps and charging pump are rendered incapable of injecting into the RCS through removing the power from the pumps by racking the breakers out under administrative control. Alternative methods of low temperature overpressure protection control may be employed using at least two independent means such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the pump control switch being placed in pull to lock and at least one valve in the discharge flow path being closed, or closing discharge MOV(s) and de-energizing the motor operator(s) under administrative control, or locking closed and tagging manual valve(s) in the discharge flow path.

The Frequency of 12 hours is sufficient, considering other indications and alarms available to the operator in the control room, to verify the required status of the equipment. The additional Frequency for SR 3.4.12.1 and SR 3.4.12.2 is necessary to allow time during the transition from MODE 3 to MODE 4 to make the pumps inoperable.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.4

The RCS vent capable of relieving > 475 gpm water flow is proven OPERABLE by verifying its open condition either:

a. Once every 12 hours for a vent path that cannot be locked.

b. Once every 31 days for a vent path that is locked, sealed, or secured in position. A removed safety or PORV fits this category.

The passive vent arrangement must only be open to be OPERABLE. This Surveillance is required to be performed if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12b.

SR 3.4.12.5

The PORV block valve must be verified open every 72 hours to provide the flow path for each required PORV to perform its function when actuated. The valve must be remotely verified open in the main control room. This Surveillance is performed if the PORV satisfies the LCO.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required removed, and the manual operator is not required locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation.

The 72-hour Frequency is considered adequate in view of other administrative controls available to the operator in the control room, such as valve position indication, that verify that the PORV block valve remains open.

SR 3.4.12.6

The required RHR suction relief valve shall be demonstrated OPERABLE by verifying both RHR suction isolation valves are open and by testing it in accordance with the Inservice Testing Program. This Surveillance is only performed if the RHR suction relief valve is being used to satisfy this LCO.

Every 31 days both RHR suction isolation valves are verified locked open, with power to the valve operator removed, to ensure that accidental closure will not occur. The “locked open” valves must be locally verified in the open position with the manual actuator locked. The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve position.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.12.7

The COT is required to be in frequency prior to decreasing RCS temperature to ≤ the COMS arming temperature specified in the PTLR or be performed within 12 hours after decreasing RCS temperature to less than or equal to the COMS arming temperature specified in the PTLR on each required PORV to verify and, as necessary, adjust its lift setpoint. The COT will verify the setpoint is within the PTLR allowed maximum limits in the PTLR. PORV actuation could depressurize the RCS and is not required. The COT is required to be performed every 31 days when RCS temperature is less than or equal to the COMS arming temperature specified in the PTLR with the reactor head in place.

The 12-hour allowance to meet the requirement considers the unlikelihood of a low temperature overpressure event during this time.

A Note has been added indicating that this SR is required to be met within 12 hours after decreasing RCS cold leg temperature to less than or equal to the COMS arming temperature specified in the PTLR.

SR 3.4.12.8

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required every 18 months to adjust the whole channel so that it responds and the valve opens within the required range and accuracy to known input.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix G, “Fracture Toughness Requirements.”

2. Generic Letter 88-11, “NRC Position on Radiation Embrittlement of Reactor Vessel Materials and Its Impact on Plant Operation.”

3. ASME Boiler and Pressure Vessel Code, Section III.

4. Watts Bar FSAR, Section 15.2, “Condition II - Faults of Moderate Frequency.”

5. Title 10, Code of Federal Regulations, Part 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors.”

6. Title 10, Code of Federal Regulations, Part 50, Appendix K, “ECCS Evaluation Models.”

7. Generic Letter 90-06, “Resolution of Generic Issue 70, 'Power-Operated Relief Valve and Block Valve Reliability, and Generic Issue 94, 'Additional Low-Temperature Overpressure Protection for Light Water Reactors,' pursuant to 10 CFR 50.44(f).”

8. Westinghouse Letter to TVA, WBT-D-5147, “Replacement PORVs for Watts Bar Unit 2,” December 2014.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can allow varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.

10 CFR 50, Appendix A, GDC 30 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the facility and the public.

A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

This LCO deals with protection of the reactor coolant pressure boundary (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 (LOCA) or steam generator tube rupture (SGTR).

BASES (continued)

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for a main steam line break (MSLB) assumes that the accident primary-to-secondary LEAKAGE from three steam generators is 150 gallons per day (gpd) per steam generator and 1 gallon per minute (gpm) from one steam generator. For an SGTR accident, the accident analysis assumes a primary-to-secondary leakage of 150 gpd per steam generator prior to the accident. Subsequent to the SGTR a leakage of 150 gpd is assumed in each of three intact steam generators and RCS blowdown flow through the ruptured tube in the faulted steam generator. Consequently, the LCO requirement to limit primary-to-secondary LEAKAGE through any one steam generator to less than or equal to 150 gpd is acceptable.

The safety analysis for the SLB accident assumes the entire 1 gpm primary-to-secondary LEAKAGE is through the affected steam generator as an initial condition. The dose consequences resulting from the SLB accident are within the limits defined in 10 CFR 100 or the staff approved licensing basis (i.e., a small fraction of these limits).

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of an off-normal condition. 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.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment air monitoring and containment pocket sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

(continued)

BASES

LCO (continued)

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through ANY One SG

The limit of 150 gallons per day (gpd) per SG (600 gpd total for all SGs) is based on the operational LEAKAGE performance criteria in NEI 97-06, Steam Generator Program Guidelines (Reference 4). The Steam Generator Program operational LEAKAGE performance criterion in NEI 97-06 states, “The RCS operational primary to secondary leakage through any one SG shall be limited to 150 gallons per day.” The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational leakage rate criterion in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

BASES (continued)

ACTIONS

A.1

Unidentified LEAKAGE or identified LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists, or primary-to-secondary LEAKAGE is not within limits, or if unidentified LEAKAGE or identified LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

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. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be met with the reactor at steady state operating conditions and near operating pressure. The SR is modified by 2 Notes. Note 1 states that this SR is not required to be performed until 12 hours after establishing steady state operation. The 12 hour allowance provides sufficient time to collect and process all necessary data after stable plant conditions are established.

Steady state operation is required to perform a proper inventory balance; calculations during maneuvering are not useful. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment pocket sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

Note 2 states that this SR is not applicable to primary-to-secondary LEAKAGE because LEAKAGE of 150 gallons per day cannot be measured accurately by an RCS water inventory balance.

The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.13.2

This SR verifies that primary-to-secondary LEAKAGE is less than or equal to 150 gallons per day through any one SG. Satisfying the primary-to-secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.17 “Steam Generator Tube Integrity,” should be evaluated. The 150 gallons per day limit is measured at room temperature as described in Ref. 5. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, all the primary-to-secondary LEAKAGE should be conservatively assumed to be from one SG.

The Surveillance is modified by a NOTE which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary-to-secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The Surveillance Frequency of 72 hours is a reasonable interval to trend primary-to-secondary LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. The primary-to-secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with EPRI guidelines (Ref. 5)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criteria 30, "Quality of Reactor Coolant Boundary."

2. Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.

3. Watts Bar FSAR, Section 15.4, "Condition IV - Limiting Faults."

4. NEI 97-06, “Steam Generator Program Guidelines.”

5. EPRI Pressurized Water Reactor Primary-to-Secondary Leak Guidelines.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3), define RCS PIVs as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB), which separate the high pressure RCS from an attached low pressure system. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage 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.

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, that could degrade the ability for low pressure injection.

The basis for this LCO is the 1975 NRC “Reactor Safety Study” (Ref. 4) that identified potential intersystem LOCAs as a significant contributor to the risk of core melt. A subsequent study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs.

PIVs are provided to isolate the RCS from the following typically connected systems:

a. Residual Heat Removal (RHR) System;

b. Safety Injection System; and

c. Chemical and Volume Control System.

The PIVs are listed in the FSAR, Section 3.9 (Ref. 6).

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.

BASES (continued)

APPLICABLE SAFETY ANALYSES

Reference 4 identified potential intersystem LOCAs as a significant contributor to the risk of core melt. The dominant accident sequence in the intersystem LOCA category is the failure of the low pressure portion of the RHR System outside of containment. The accident is the result of a postulated failure of the PIVs, which are part of the RCPB, and the subsequent pressurization of the RHR System downstream of the PIVs from the RCS. Because the low pressure portion of the RHR System is typically designed for 600 psig, overpressurization failure of the RHR low pressure line would result in a LOCA outside containment and subsequent risk of core melt.

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.

RCS PIV leakage satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

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.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm. The previous criterion of 1 gpm for all valve sizes imposed an unjustified penalty on the larger valves without providing information on potential valve degradation and resulted in higher personnel radiation exposures. A study concluded a leakage rate limit based on valve size was superior to a single allowable value.

Reference 7 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) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases, 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.

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 4, valves in the RHR flow path are not required to meet the requirements of this LCO when in or during the transition to or from the RHR mode of operation.

In MODES 5 and 6, 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.

ACTIONS

The Actions are modified by two Notes. Note 1 provides clarification that each flow path allows separate entry into a Condition. This is allowed based upon the functional independence of the 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.

A.1 and A.2

The flow path must be isolated. Required Actions A.1 and A.2 are modified by a Note that the valve used for isolation must meet the same leakage requirements as the PIVs and must be within the RCPB.

Required Action A.1 requires that the isolation with one valve must be performed within 4 hours. Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected system if leakage cannot be reduced. The 4-hour Completion Time allows the actions and restricts the operation with leaking isolation valves.

The 72 hour Completion Time after exceeding the limit allows for the restoration of the leaking PIV to OPERABLE status. This timeframe considers the time required to complete this Action and the low probability of a second valve failing during this period.

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 requirement does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This Action may reduce the leakage and also reduces the potential for a LOCA outside the containment. 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.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 and Required Action A.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition.

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.

Testing is to be performed every 18 months, a typical refueling cycle, if the plant does not go into MODE 5 for at least 7 days. The 18 month Frequency is consistent with 10 CFR 50.55a(g) (Ref. 8) as contained in the Inservice Testing Program, is within the frequency allowed by the American Society of Mechanical Engineers (ASME) OM Code (Ref. 7), and is based on the need to perform such surveillances 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.

In addition, testing must be performed once after the valve has been opened by flow or exercised to ensure tight reseating. PIVs disturbed in the performance of this Surveillance should also be tested unless documentation shows that an infinite testing loop cannot practically be avoided. Testing must be performed within 24 hours after the valve has been reseated. Within 24 hours is a reasonable and practical time limit for performing this test after opening or reseating a valve.

The leakage limit is to be met at the RCS pressure associated with MODES 1 and 2. This permits leakage testing at high differential pressures with stable conditions not possible in the MODES with lower pressures.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

Entry into MODES 3 and 4 is allowed to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance. The Note that allows this provision is complementary to the Frequency of prior to entry into MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 9 months. In addition, this Surveillance is not required to be performed on the RHR System when the RHR System is aligned to the RCS in the shutdown cooling mode of operation. PIVs contained in the RHR shutdown cooling flow path must be leakage rate tested after RHR is secured and stable unit conditions and the necessary differential pressures are established.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Section 50.2, “Definitions - Reactor Coolant Pressure Boundary.”

2. Title 10, Code of Federal Regulations, Part 50, Section 50.55a, “Codes and Standards,” Subsection (c), “Reactor Coolant Pressure Boundary.”

3. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section V, “Reactor Containment,” General Design Criterion 55, “Reactor Coolant Pressure Boundary Penetrating Containment.”

4. U.S. Nuclear Regulatory Commission (NRC), “Reactor Safety Study - An Assessment of Accident Risks in U.S. Commercial Nuclear Power Plants,” Appendix V, WASH-1400 (NUREG-75/014), October 1975.

5. U.S. NRC, “The Probability of Intersystem LOCA: Impact Due to Leak Testing and Operational Changes,” NUREG-0677, May 1980.

6. Watts Bar FSAR, Section 3.9, “Mechanical Systems and Components” (Table 3.9-17).

7. American Society of Mechanical Engineers (ASME) OM Code, “Code for Operation and Maintenance of Nuclear Power Plants.”

8. Title 10, Code of Federal Regulations, Part 50, Section 50.55a, “Codes and Standards,” Subsection (g), “Inservice Inspection Requirements.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of Appendix A to 10 CFR 50 (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.

Leakage detection systems must have the capability to detect significant reactor coolant pressure boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE.

Industry practice has shown that water flow changes of 0.5 gpm to 1.0 gpm can be readily detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The containment pocket sump used to collect unidentified LEAKAGE is instrumented to alarm for increases of 0.5 gpm to 1.0 gpm in the normal flow rates. This sensitivity is acceptable for detecting increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. Instrument sensitivity of 10^{-9} μCi/cc radioactivity for particulate monitoring is practical for this leakage detection system. A radioactivity detection system is included for monitoring particulate activity because of its sensitivity and rapid response to RCS LEAKAGE.

(continued)

BASES

BACKGROUND (continued)

An atmospheric gaseous radioactivity monitor will provide a positive indication of leakage in the event that high levels of reactor coolant gaseous activity exist due to fuel cladding defects. The effectiveness of the atmospheric gaseous radioactivity monitors depends primarily on the activity of the reactor coolant and also, in part, on the containment volume and the background activity level. Shortly after startup and also during steady state operation with low levels of fuel defects, the level of radioactivity in the reactor coolant may be too low for the containment atmosphere gaseous radiation monitors to detect a reactor coolant leak of 1 gpm within one hour. Atmospheric gaseous radioactivity monitors are not required by this LCO.

The sample lines supplying the radioactivity monitoring instrumentation are heated (heat traced) to ensure that a representative sample can be obtained. During periods when the heat tracing is inoperable, the particulate channel of the radioactivity monitoring instrumentation is inoperable and grab samples for particulates may not be taken using the sample lines.

An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Dew point temperature measurements can thus be used to monitor humidity levels of the containment atmosphere as an indicator of potential RCS LEAKAGE. A 1°F increase in dew point is well within the sensitivity range of available instruments.

Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable and should be compared to observed increases in liquid flow into or from the containment pocket sump. Humidity level monitoring is considered most useful as an indirect alarm or indication to alert the operator to a potential problem. Humidity monitors are not required by this LCO.

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The relevance of temperature and pressure measurements are affected by containment free volume and, for temperature, detector location. Alarm signals from these instruments can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system response times and sensitivities are described in the FSAR (Ref. 3).

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leak detrimental to the safety of the unit and the public occur. RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii).

LCO

One method of protecting against large RCS leakage derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition when RCS LEAKAGE indicates possible RCPB degradation.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment pocket sump level monitor, in combination with a particulate radioactivity monitor, provides an acceptable minimum.

The sample lines supplying the radioactivity monitoring instrumentation are heated (heat traced) to ensure that a representative sample can be obtained.

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is to be ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

BASES (continued)

ACTIONS

A.1 and A.2

With the required containment pocket sump level monitor inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere particulate radioactivity monitor will provide indications of changes in leakage. Together with the atmosphere monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage.

Restoration of the required containment pocket sump level monitor to OPERABLE status within a Completion Time of 30 days is required to regain the function after the monitor's failure. This time is acceptable, considering the Frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

B.1.1, B.1.2, and B.2

With the particulate containment atmosphere radioactivity monitoring instrumentation channel inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

During periods when the heat tracing is inoperable for the sample lines supplying the radioactivity monitoring instrumentation, the particulate channel of the instrumentation is inoperable and grab samples for particulates may not be taken using the sample lines.

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment atmosphere particulate radioactivity monitor.

The 24-hour interval provides periodic information that is adequate to detect leakage. The 30-day Completion Time recognizes at least one other form of leakage detection is available.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If a Required Action of Condition A or B cannot be met, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 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 all required monitors inoperable, no automatic means of monitoring leakage are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere particulate radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.15.2

SR 3.4.15.2 requires the performance of a COT on the required containment atmosphere particulate radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. The test verifies the alarm setpoint and the relative accuracy of the instrument string. The Frequency of 92 days considers instrument reliability, and operating experience has shown that it is proper for detecting degradation.

SR 3.4.15.3 and SR 3.4.15.4

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 18 months is a typical refueling cycle and considers channel reliability. Again, operating experience has proven that this Frequency is acceptable.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, General Design Criterion 30, "Quality of Reactor Coolant Pressure Boundary."

2. Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," Revision 0, May 1973.

3. Watts Bar FSAR, Section 5.2.7, "RCPB Leakage Detection Systems."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The maximum dose to the whole body and the thyroid that an individual at the site boundary can receive for 2 hours during an accident is specified in 10 CFR 100 (Ref. 1). The maximum dose to the whole body and the thyroid that an individual occupying the Main Control Room can receive for the accident duration is specified in 10 CFR 50, Appendix A, GDC 19. The limits on specific activity ensure that the doses are held to a small fraction of the 10 CFR 100 limits and within the 10 CFR 50, Appendix A, GDC 19 limits during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the offsite and Main Control Room radioactivity dose consequences in the event of a steam generator tube rupture (SGTR) or main steam line break (MSLB) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the 2 hour dose at the site boundary to a small fraction of the 10 CFR 100 dose guideline limits, and ensure the Main Control Room accident dose is within the appropriate 10 CFR 50, Appendix A, GDC 19 dose guideline limits.

The evaluations showed the potential offsite and Main Control Room dose levels for a SGTR and MSLB accident were within the appropriate 10 CFR 100 and GDC 19 guideline limits.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensures that the resulting 2 hour doses at the site boundary and Main Control Room accident doses will not exceed the appropriate 10 CFR 100 dose guideline limits and 10 CFR 50, Appendix A, GDC 19 dose guideline limits following a SGTR or MSLB accident. The SGTR and MSLB safety analysis (Ref. 2) assumes the specific activity of the reactor coolant at the LCO limit and an existing reactor coolant steam generator (SG) tube leakage rate of 150 gallons per day (GPD). The safety analysis assumes the specific activity of the secondary coolant at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.14, "Secondary Specific Activity."

The analysis for the SGTR and MSLB accidents establish the acceptance limits for RCS specific activity. Reference to these analyses is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

The analyses are for two cases of reactor coolant specific activity. One case assumes specific activity at 0.265 μCi/gm DOSE EQUIVALENT I-131 with an iodine spike immediately after the accident that increases the iodine activity in the reactor coolant by a factor of 500 times the iodine production rate necessary to maintain a steady state iodine concentration of 0.265 μCi/gm DOSE EQUIVALENT I-131. The second case assumes the initial reactor coolant iodine activity at 14 μCi/gm DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. In both cases, the noble gas activity in the reactor coolant equals the LCO limit of 100/ $\bar{E}$ μCi/gm for gross specific activity.

The analysis also assumes a loss of offsite power at the same time as the SGTR and MSLB event. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal or an RCS overtemperature ΔT signal. The MSLB results in a reactor trip due to low steam pressure.

The coincident loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG power operated relief valves and the main steam safety valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The safety analysis shows the radiological consequences of an SGTR and MSLB accident are within the appropriate 10 CFR 100 and 10 CFR 50, Appendix A, GDC 19 dose guideline limits. Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed 14 μCi/gm DOSE EQUIVALENT I-131, in the applicable specification, for more than 48 hours. The safety analysis has concurrent and pre-accident iodine spiking levels up to 14 μCi/gm DOSE EQUIVALENT I-131.

The limits on RCS specific activity are also used for establishing standardization in radiation shielding and plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specific iodine activity is limited to 0.265 μCi/gm DOSE EQUIVALENT I-131, and the gross specific activity in the reactor coolant is limited to the number of μCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy of the sum of the average beta and gamma energies of the coolant nuclides). The limit on DOSE EQUIVALENT I-131 ensures the 2 hour thyroid dose to an individual at the site boundary and accident dose to personnel in the Main Control Room during the Design Basis Accident (DBA) will be within the allowed thyroid dose. The limit on gross specific activity ensures the 2 hour whole body dose to an individual at the site boundary and accident dose to personnel in the Main Control Room during the DBA will be within the allowed whole body dose.

The SGTR and MSLB accident analysis (Ref. 2) shows that the 2 hour site boundary dose levels and Main Control Room accident dose are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of a SGTR or MSLB, lead to site boundary doses that exceed the 10 CFR 100 dose guideline limits, or Main Control Room accident dose that exceed the 10 CFR 50, Appendix A, GDC 19 dose limits.

BASES (continued)

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS average temperature ≥ 500°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and gross specific activity are necessary to contain the potential consequences of an accident to within the acceptable Main Control Room and site boundary dose values.

For operation in MODE 3 with RCS average temperature < 500°F, and in MODES 4 and 5, the release of radioactivity in the event of a SGTR is unlikely since the saturation pressure of the reactor coolant is below the lift pressure settings of the main steam safety valves.

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate that the limit of 14 μCi/gm is not exceeded. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is done to continue to provide a trend.

The DOSE EQUIVALENT I-131 must be restored to within limits within 48 hours. The Completion Time of 48 hours is required, if the limit violation resulted from normal iodine spiking.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

With the gross specific activity in excess of the allowed limit, an analysis must be performed within 4 hours to determine DOSE EQUIVALENT I-131. The Completion Time of 4 hours is required to obtain and analyze a sample.

The change within 6 hours to MODE 3 and RCS average temperature < 500°F lowers the saturation pressure of the reactor coolant below the setpoints of the main steam safety valves and prevents venting the SG to the environment in an SGTR event. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

C.1

If a Required Action and the associated Completion Time of Condition A is not met or if the DOSE EQUIVALENT I-131 is greater than 14 μCi/gm, the reactor must be brought to MODE 3 with RCS average temperature < 500°F within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the gross specific activity of the reactor coolant at least once every 7 days. While basically a quantitative measure of radionuclides with half lives longer than 15 minutes, excluding iodines, this measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in gross specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The Surveillance is applicable in MODES 1 and 2, and in MODE 3 with T_{avg} at least 500°F. The 7-day Frequency considers the unlikelihood of a gross fuel failure during the time.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.16.2

This Surveillance is performed in MODE 1 only to ensure iodine remains within limit during normal operation and following rapid power changes when fuel failure is more apt to occur. The 14-day Frequency is adequate to trend changes in the iodine activity level, considering gross activity is monitored every 7 days. The Frequency, between 2 hours and 6 hours after a power change ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following fuel failure; samples at other times would provide inaccurate results.

SR 3.4.16.3

A radiochemical analysis for $\bar{E}$ determination is required every 184 days (6 months) with the plant operating in MODE 1 equilibrium conditions. The $\bar{E}$ determination directly relates to the LCO and is required to verify plant operation within the specified gross activity LCO limit. The analysis for $\bar{E}$ is a measurement of the average energies per disintegration for isotopes with half lives longer than 15 minutes, excluding iodines. The Frequency of 184 days recognizes $\bar{E}$ does not change rapidly.

This SR has been modified by a Note that indicates sampling is required to be performed within 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for at least 48 hours. This ensures that the radioactive materials are at equilibrium so the analysis for $\bar{E}$ is representative and not skewed by a crud burst or other similar abnormal event.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 100.11, “Determination of Exclusion Area, Low Population Zone, and Population Center Distance,” 1973.

2. Watts Bar FSAR, Section 15.4, “Condition IV - Limiting Faults.”

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops - MODES 1 and 2," LCO 3.4.5, "RCS Loops - MODE 3," LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled."

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 5.7.2.12, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.7.2.12, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.7.2.12. Meeting the SG performance criteria provides reasonable assurance of maintaining tube integrity at normal and accident conditions.

The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

BASES (continued)

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of an SGTR event assumes a bounding primary to secondary LEAKAGE rate equal to the operational LEAKAGE rate limits in LCO 3.4.13, “RCS Operational LEAKAGE,” plus the leakage rate associated with a double-ended rupture of a single tube. The accident analysis for a SGTR assumes the contaminated secondary fluid is only briefly released to the atmosphere via safety valves and the majority is discharged to the main condenser.

The analysis for design basis accidents and transients other than an SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture). In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary LEAKAGE of 150 gallons per day (gpd) per unfaulted steam generator and 1 gallon per minute (gpm) in the faulted steam generator. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, “RCS Specific Activity,” limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 2), and 10 CFR 100 (Ref. 3) or the NRC approved licensing basis.

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the plugging criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. If a tube was determined to satisfy the plugging criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, an SG tube is defined as the entire length of the tube, including the tube wall, between the tube-to-tubesheet weld at the tube inlet and the tube-to-tubesheet weld at the tube outlet. The tube-to-tubesheet weld is not considered part of the tube.

(continued)

BASES

LCO (continued)

An SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.7.2.12, “Steam Generator Program,” and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, “The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation.” Tube collapse is defined as, “For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero.” The structural integrity performance criterion provides guidance on assessing loads that have a significant effect on burst or collapse. In that context, the term “significant” is defined as “An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established.” For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions), and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Regulatory Guide 1.121 (Ref. 5).

(continued)

BASES

LCO (continued)

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than an SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 1 gpm in the faulted SG. The accident induced leakage rate includes any primary-to-secondary LEAKAGE existing prior to the accident in addition to primary-to-secondary LEAKAGE induced during the accident.

The operational LEAKAGE performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational LEAKAGE is contained in LCO 3.4.13, "RCS Operational LEAKAGE," and limits primary-to-secondary LEAKAGE through any one SG to 150 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to an SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary-to-secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS

The ACTIONS are modified by a Note that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequent affected SG tubes are governed by subsequent Condition entry, and application of associated Required Actions.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube plugging criteria but were not plugged in accordance with the Steam Generator Program as required by SR 3.4.17.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG plugging criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if an SG tube that should have been plugged, has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

A Completion Time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with a SG tube that may not have tube integrity.

If the evaluation determines that the affected tube(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring assessment determines the “as found” condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube plugging criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, nondestructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.17.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.7.2.12 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections. If crack indications are found in any SG tube, the maximum inspection interval for all affected and potentially affected SGs is restricted by Specification 5.7.2.12 until subsequent inspections support extending the inspection interval.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.17.2

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. The tube plugging criteria delineated in Specification 5.7.2.12 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube plugging criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

The Frequency of prior to entering MODE 4 following an SG inspection ensures that the Surveillance has been completed and all tubes meeting the plugging criteria are plugged prior to subjecting the SG tubes to significant primary-to-secondary pressure differential.

REFERENCES

1. NEI 97-06, “Steam Generator Program Guidelines.”
2. 10 CFR 50 Appendix A, GDC 19, Control Room.
3. 10 CFR 100, Reactor Site Criteria.
4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.
5. Regulatory Guide 1.121, “Basis for Plugging Degraded Steam Generator Tubes,” August 1976.
6. EPRI, “Pressurized Water Reactor Steam Generator Examination Guidelines.”

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Accumulators

BASES

BACKGROUND

The functions of the ECCS accumulators are to supply water to the reactor vessel during the blowdown phase of a loss of coolant accident (LOCA), to provide inventory to help accomplish the refill phase that follows thereafter, and to provide Reactor Coolant System (RCS) makeup for a small break LOCA.

The blowdown phase of a large break LOCA is the initial period of the transient during which the RCS departs from equilibrium conditions, and heat from fission product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. The blowdown phase of the transient ends when the RCS pressure falls to a value approaching that of the containment atmosphere.

In the refill phase of a LOCA, which immediately follows the blowdown phase, reactor coolant inventory has vacated the core through steam flashing and ejection out through the break. The core is essentially in adiabatic heatup. The balance of accumulator inventory is then available to help fill voids in the lower plenum and reactor vessel downcomer so as to establish a recovery level at the bottom of the core and ongoing reflood of the core with the addition of safety injection (SI) water.

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. The accumulators are passive components, since no operator or control actions are required in order for them to perform their function. Internal accumulator tank pressure is sufficient to discharge the accumulator contents to the RCS, if RCS pressure decreases below the accumulator pressure.

Each accumulator is piped into an RCS cold leg via an accumulator line and is isolated from the RCS by a motor operated isolation valve and two check valves in series. The motor operated isolation valves are interlocked by P-11 with the pressurizer pressure measurement channels to ensure that the valves will automatically open as RCS pressure increases to above the permissive circuit P-11 setpoint.

(continued)

BASES

BACKGROUND (continued)

This interlock also prevents inadvertent closure of the valves during normal operation prior to an accident. Although not required for accident mitigation, the valves will automatically open as a result of an SI signal. These features ensure that the valves meet the requirements of the Institute of Electrical and Electronic Engineers (IEEE) Standard 279-1971 (Ref. 1) for "operating bypasses" and that the accumulators will be available for injection without reliance on operator action.

The accumulator size, water volume, and nitrogen cover pressure are selected so that three of the four accumulators are sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that three accumulators are adequate for this function is consistent with the LOCA assumption that the entire contents of one accumulator will be lost via the RCS pipe break during the blowdown phase of the LOCA.

APPLICABLE SAFETY ANALYSES

The accumulators are assumed OPERABLE in both the large and small break LOCA analyses at full power (Ref. 2). These are the Design Basis Accidents (DBAs) that establish the acceptance limits for the accumulators. Reference to the analyses for these DBAs is used to assess changes in the accumulators as they relate to the acceptance limits.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of ECCS flow. In the early stages of a LOCA, with or without a loss of offsite power, the accumulators provide the sole source of makeup water to the RCS. The assumption of loss of offsite power is also considered to determine if it yields limiting results. The loss of offsite power assumption imposes a delay wherein the ECCS pumps cannot deliver flow until the diesel generators start, come to rated speed, and go through their timed loading sequence. In cold leg break scenarios, the entire contents of one accumulator are assumed to be lost through the break.

The limiting large break LOCA is a double ended guillotine break in the cold leg. During this event, the accumulators discharge to the RCS as soon as RCS pressure decreases to below accumulator pressure.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

As a conservative estimate, no credit is taken for ECCS pump flow until an effective delay has elapsed. This delay accounts for the diesels starting and the pumps being loaded and delivering full flow. The delay time is conservatively set to account for SI signal generation. During this time, the accumulators are analyzed as providing the sole source of emergency core cooling. No operator action is assumed during the blowdown phase of a large break LOCA.

The worst case small break LOCA analyses also assume a time delay before pumped flow reaches the core. For the larger range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated solely by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and centrifugal charging pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the centrifugal charging pumps become solely responsible for terminating the temperature increase.

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46, Paragraph b (Ref. 3) will be met following a LOCA:

a. Maximum fuel element cladding temperature is $\leq$ 2200°F;

b. Maximum cladding oxidation is $\leq$ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is $\leq$ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react; and

d. Core is maintained in a coolable geometry.

Since the accumulators discharge during the blowdown phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

For the small break LOCA analysis, a nominal contained accumulator water volume of 7855 gallons is used, while a range of 7518 - 8191 gallons was used for the large break LOCA analysis. The contained water volume is the same as the deliverable volume for the accumulators, since the accumulators are emptied, once discharged. To allow for instrument inaccuracy, values of 7630 gallons and 8000 gallons are specified.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The minimum boron concentration setpoint is used in the post LOCA boron concentration calculation. The calculation is performed to assure reactor subcriticality in a post LOCA environment. Of particular interest is the large break LOCA, since no credit is taken for control rod assembly insertion. A reduction in the accumulator minimum boron concentration would produce a subsequent reduction in the available containment sump concentration for post LOCA shutdown and an increase in the maximum sump pH. The maximum boron concentration is used in determining the cold leg to hot leg recirculation injection switchover time and minimum sump pH.

The small break LOCA analysis is performed at the minimum nitrogen cover pressure, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak clad temperature benefit. The maximum nitrogen cover pressure analysis limit of 690 psig prevents accumulator relief valve actuation, and ultimately preserves accumulator integrity. The LOCA analyses support a range of 585 psig to 690 psig. To account for the accumulator tank design pressure rating, and to allow for instrument accuracy values of $\geq$ 610 psig and $\leq$ 660 psig are specified for the pressure indicator in the main control room.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. 2 and 4).

The accumulators satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO establishes the minimum conditions required to ensure that the accumulators are available to accomplish their core cooling safety function following a LOCA. Four accumulators are required to ensure that 100% of the contents of three of the accumulators will reach the core during a LOCA. This is consistent with the assumption that the contents of one accumulator spill through the break. If less than three accumulators are injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 3) could be violated.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above 1000 psig, and the limits established in the SRs for contained volume, boron concentration, and nitrogen cover pressure must be met.

BASES (continued)

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure > 1000 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures > 1000 psig. At pressures ≤ 1000 psig, the rate of RCS blowdown is such that the ECCS pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 (Ref. 3) limit of 2200°F.

In MODE 3, with RCS pressure ≤ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated isolation valves are closed to isolate the accumulators from the RCS. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this Condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analysis techniques demonstrate that the accumulators do not discharge following a large main steam line break for the majority of plants. Even if they do discharge, their impact is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits.

(continued)

BASES

ACTIONS (continued)

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 24 hours. In this Condition, the required contents of three accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 24-hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions. The 24 hours allowed to restore an inoperable accumulator to OPERABLE status is justified in WCAP-15049-A, Rev. 1 (Ref. 6).

C.1 and C.2

If the accumulator cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and pressurizer pressure reduced to ≤ 1000 psig within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

If more than one accumulator is inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator valve should be verified to be fully open every 12 hours. This verification ensures that the accumulators are available for injection and ensures timely discovery if a valve should be less than fully open. If an isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change with power removed, a closed valve could result in not meeting accident analyses assumptions. This Frequency is considered reasonable in view of other administrative controls that ensure a mispositioned isolation valve is unlikely.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.2 and SR 3.5.1.3

Every 12 hours, borated water volume and nitrogen cover pressure are verified for each accumulator (Refer to the note below.). This Frequency is sufficient to ensure adequate injection during a LOCA. Because of the static design of the accumulator, a 12-hour Frequency usually allows the operator to identify changes before limits are reached. Operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

Note: In the discussion contained in the Applicable Safety Analyses of this Bases section, the borated water volume and nitrogen cover pressure specified for SR 3.5.1.2 and SR 3.5.1.3 account for instrument accuracy.

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator every 31 days since the static design of the accumulators limits the ways in which the concentration can be changed. The 31-day Frequency is adequate to identify changes that could occur from mechanisms such as stratification or inleakage. Sampling the affected accumulator within 6 hours after a 75 gallons (1% volume) increase will identify whether inleakage has caused a reduction in boron concentration to below the required limit. This is consistent with the recommendation of NUREG-1366 (Ref. 5).

SR 3.5.1.5

Verification every 31 days that power is removed from each accumulator isolation valve operator when the pressurizer pressure is ≥ 1000 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, only two accumulators would be available for injection given a single failure coincident with a LOCA. Since power is removed under administrative control, the 31-day Frequency will provide adequate assurance that power is removed.

This SR allows power to be supplied to the motor operated isolation valves when pressurizer pressure is < 1000 psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during plant startups or shutdowns. Even with power supplied to the valves, inadvertent closure is prevented by the RCS pressure interlock associated with the valves.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.5 (continued)

Should closure of a valve occur in spite of the interlock, the SI signal provided to the valves would open a closed valve in the event of a LOCA. This design feature still exists, but is no longer required for accident mitigation.

REFERENCES

1. IEEE Standard 279-1971, "Criteria for Protection Systems for Nuclear Power Generating Stations."

2. Watts Bar FSAR, Section 6.3, "Emergency Core Cooling System."

3. Title 10, Code of Federal Regulations, Part 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Power Plants."

4. Watts Bar FSAR, Section 15.0, "Accident Analysis."

5. NUREG-1366, Improvements to Technical Specifications Surveillance Requirements, December 1992.

6. WCAP-15049-A, Rev. 1, April, 1999.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS - Operating

BASES

BACKGROUND

The function of the ECCS is to provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents:

a. Loss of coolant accident (LOCA), coolant leakage greater than the capability of the normal charging system;

b. Rod ejection accident;

c. Loss of secondary coolant accident, including uncontrolled steam release or loss of feedwater; and

d. Steam generator tube rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to significant power.

There are three phases of ECCS operation: injection, cold leg recirculation, and hot leg recirculation. In the injection phase, water is taken from the refueling water storage tank (RWST) and injected into the Reactor Coolant System (RCS) through the cold legs. When sufficient water is removed from the RWST to ensure that enough boron has been added to maintain the reactor subcritical and the containment sumps have enough water to supply the required net positive suction head to the ECCS pumps, suction is switched to the containment sump for cold leg recirculation. Approximately 3.0 hours after event initiation, the ECCS flow is shifted to the hot leg recirculation phase to provide a backflush, which would reduce the boiling in the top of the core and any resulting boron precipitation.

The ECCS consists of three separate subsystems: centrifugal charging (high head), safety injection (SI) (intermediate head), and residual heat removal (RHR) (low head). Each subsystem consists of two redundant, 100% capacity trains. The ECCS accumulators and the RWST are also part of the ECCS, but are not considered part of an ECCS flow path as described by this LCO.

(continued)

BASES

BACKGROUND (continued)

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the RWST can be injected into the RCS following the accidents described in this LCO. The major components of each subsystem are the centrifugal charging pumps, the RHR pumps, heat exchangers, and the SI pumps. Each of the three subsystems consists of two 100% capacity trains that are interconnected and redundant such that either train is capable of supplying 100% of the flow required to mitigate the accident consequences. This interconnecting and redundant subsystem design provides the operators with the ability to utilize components from opposite trains to achieve the required 100% flow to the core.

During the injection phase of LOCA recovery, a suction header supplies water from the RWST to the ECCS pumps. Separate piping supplies each subsystem and each train within the subsystem. The discharge from the SI and RHR pumps divides and feeds an injection line to each of the RCS cold legs. Throttle valves and piping hydraulic design are set to balance the flow to the RCS and prevent pump runout. This balance ensures sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs.

For LOCAs that are too small to depressurize the RCS below the shutoff head of the SI pumps, the centrifugal charging pumps supply water until the RCS pressure decreases below the SI pump shutoff head. During this period, the steam generators are used to provide part of the core cooling function.

During the recirculation phase of LOCA recovery, RHR pump suction is transferred to the containment sump. The RHR pumps then supply the other ECCS pumps. Initially, recirculation is through the same paths as the injection phase. Subsequently, recirculation provides injection to the hot and cold legs simultaneously.

The centrifugal charging subsystem of the ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a main steam line break (MSLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

During low temperature conditions in the RCS, limitations are placed on the maximum number of ECCS pumps that may be OPERABLE. Refer to the Bases for LCO 3.4.12, “Cold Overpressure Mitigation System (COMS),” for the basis of these requirements.

(continued)

BASES

BACKGROUND (continued)

The ECCS subsystems are actuated upon receipt of an SI signal. The actuation of safeguard loads is accomplished in a programmed time sequence for a loss of offsite power. If offsite power is available, the safeguard loads start immediately. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the diesel generators (DGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive accumulators and the RWST covered in LCO 3.5.1, “Accumulators,” and LCO 3.5.4, “Refueling Water Storage Tank (RWST),” provide the cooling water necessary to meet GDC 35 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46, Paragraph b (Ref. 2), will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. Core is maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

The LCO also limits the potential for a post trip return to power following an MSLB event and ensures that containment temperature limits are met.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Each ECCS subsystem is taken credit for in a large break LOCA event at full power (Refs. 3 and 4). This event establishes the requirement for runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The centrifugal charging pumps and SI pumps are credited in a small break LOCA event. This event establishes the flow and discharge head at the design point for the centrifugal charging pumps. The SGTR and MSLB events also credit the centrifugal charging pumps. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. A large break LOCA event, with or without loss of offsite power and with a single failure disabling one ECCS train (in the containment pressure analysis, both DG trains are conservatively assumed to operate due to requirements for modeling full active containment heat removal system operation); and

b. A small break LOCA event, with a loss of offsite power and a single failure disabling one ECCS train.

During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod insertion for small breaks. Following depressurization, emergency cooling water is injected into the cold legs, flows into the downcomer, fills the lower plenum, and refloods the core.

The effects on containment mass and energy releases are accounted for in appropriate analyses (Refs. 3 and 4). The LCO ensures that an ECCS train will deliver sufficient water to match boil off rates soon enough to minimize the consequences of the core being uncovered following a large LOCA. It also ensures that the centrifugal charging and SI pumps will deliver sufficient water and boron during a small LOCA to maintain core subcriticality. For smaller LOCAs, the centrifugal charging pump delivers sufficient fluid to maintain RCS inventory. For a small break LOCA, the steam generators continue to serve as the heat sink, providing part of the required core cooling.

The ECCS trains satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

In MODES 1, 2, and 3, two independent (and redundant) ECCS trains are required to ensure that sufficient ECCS flow is available, assuming a single failure affecting either train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents.

(continued)

BASES

LCO (continued)

In MODES 1, 2, and 3, two independent (and redundant) ECCS trains are required to ensure that sufficient ECCS flow is available, assuming a single failure affecting either train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents.

In MODES 1, 2, and 3, an ECCS train consists of a centrifugal charging subsystem, an SI subsystem, and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an SI signal and automatically transferring suction to the containment sump.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS pumps and their respective supply headers to each of the four cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment sump and to supply its flow to the RCS hot and cold legs.

The flow path for each train must maintain its designed independence to ensure that no single failure can disable both ECCS trains.

As indicated in Note 1, the SI flow paths may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. The flow path is readily restorable from the control room. As indicated in Note 2, operation in MODE 3 with safety injection pumps and charging pumps made incapable of injecting in order to facilitate entry into or exit from the Applicability of LCO 3.4.12, “Cold Overpressure Mitigation System (COMS)” is necessary with the COMS arming temperature specified in the PTLR. LCO 3.4.12 requires that certain pumps be rendered incapable of injecting at and below the COMS arming temperature. When this temperature is at or near the MODE 3 boundary temperature, time is needed to make pumps incapable of injecting prior to entering the COMS Applicability, and provide time to restore the inoperable pumps to OPERABLE status on exiting the COMS Applicability.

APPLICABILITY

In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. The centrifugal charging pump performance is based on a small break LOCA, which establishes the pump performance curve and has less dependence on power. The

(continued)

BASES

APPLICABILITY (continued)

SI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

This LCO is only applicable in MODE 3 and above. Below MODE 3, the SI signal setpoint is manually bypassed by operator control, and system functional requirements are relaxed as described in LCO 3.5.3, "ECCS - Shutdown."

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

With one or more trains inoperable and at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72-hour Completion Time is based on an NRC reliability evaluation (Ref. 5) and is a reasonable time for repair of many ECCS components.

An ECCS train is inoperable if it is not capable of delivering design flow to the RCS. Individual components are inoperable if they are not capable of performing their design function or supporting systems are not available.

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the ECCS. The intent of this Condition is to maintain a combination of equipment such that 100% of the ECCS flow equivalent to a single OPERABLE ECCS train remains available. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

(continued)

BASES

ACTIONS

A.1 (continued)

An event accompanied by a loss of offsite power and the failure of a DG can disable one ECCS train until power is restored. A reliability analysis (Ref. 5) has shown that the impact of having one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

Reference 6 describes situations in which one component, such as an RHR crossover valve, can disable both ECCS trains. With one or more component(s) inoperable such that 100% of the flow equivalent to a single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

If the inoperable trains cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render both ECCS trains inoperable. Securing these valves in position by removal of power or by key locking the control in the correct position ensures that they cannot change position as a result of an active failure or be inadvertently misaligned. These valves are of the type, described in Reference 6, that can disable the function of both ECCS trains and invalidate the accident analyses. A 12-hour Frequency is considered reasonable in view of other administrative controls that will ensure a mispositioned valve is unlikely.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a non-accident position provided the valve will automatically reposition within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mis-positioned are in the correct position. The 31-day Frequency is appropriate because the valves are operated under administrative control, and an improper valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.2.3

With the exception of the operating centrifugal charging pump, the ECCS pumps are normally in a standby, non-operating mode. As such, flow path piping has the potential to develop voids and pockets of entrained gases. Maintaining the piping from the ECCS pumps to the RCS full of water by venting the ECCS pump casings and accessible suction and discharge piping high points ensures that the system will perform properly, injecting its full capacity into the RCS upon demand.* This will also prevent water hammer, pump cavitation, and pumping of non-condensible gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SI signal or during shutdown cooling. The 31-day Frequency takes into consideration the gradual nature of gas accumulation in the ECCS piping and the procedural controls governing system operation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.3 (continued)

* For the accessible locations, UT may be substituted to demonstrate the piping is full of water. An accessible ECCS high point is defined as one that:

1) Has a vent connection installed.

2) The high point can be vented with the dose received remaining within ALARA expectations. ALARA for venting ECCS high point vents is considered to not be within ALARA expectations when the planned, intended collective dose for the activity is unjustifiably higher than industry norm, or the licensee's past experience, for this (or similar) work activity.

3) The high point can be vented with industrial safety expectations remaining within the industry norm.

SR 3.5.2.4

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by the American Society of Mechanical Engineers (ASME) OM Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pumps baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. SRs are specified in the Inservice Testing Program, which encompasses the ASME OM Code. The ASME OM Code provides the activities and Frequencies necessary to satisfy the requirements.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.5 and 3.5.2.6

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SI signal and that each ECCS pump starts on receipt of an actual or simulated SI signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative control. The 18-month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for unplanned plant transients if the Surveillances were performed with the reactor at power. The 18-month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the Inservice Testing Program.

SR 3.5.2.7

Realignment of valves in the flow path on an SI signal is necessary for proper ECCS performance. These valves are secured in a throttled position for restricted flow to a ruptured cold leg, ensuring that the other cold legs receive at least the required minimum flow. The 18-month Frequency is based on the same reasons as those stated in SR 3.5.2.5 and SR 3.5.2.6.

SR 3.5.2.8

Periodic inspections of the containment sump suction inlet ensure that it is unrestricted and stays in proper operating condition. The advanced sump strainer design installed at WBN incorporates both the trash rack function and the screen function. Inspection of the advanced strainer constitutes fulfillment of the trash rack/screen inspection. The 18-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, on the need to have access to the location, and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. This Frequency has been found to be sufficient to detect abnormal degradation and is confirmed by operating experience.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 35, “Emergency Core Cooling System.”

2. Title 10, Code of Federal Regulations, Part 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plant.”

3. Watts Bar FSAR, Section 6.3, “Emergency Core Cooling System.”

4. FSAR Bar FSAR, Section 15.0, “Accident Analysis.”

5. NRC Memorandum to V. Stello, Jr., from R. L. Baer, “Recommended Interim Revisions to LCOs for ECCS Components,” December 1, 1975.

6. IE Information Notice No. 87-01, “RHR Valve Misalignment Causes Degradation of ECCS in PWRs,” January 6, 1987.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS - Shutdown

BASES

BACKGROUND

The Background section for Bases 3.5.2, “ECCS - Operating,” is applicable to these Bases, with the following modifications (Ref. 1).

In MODE 4, the required ECCS train consists of two separate subsystems: the high head centrifugal charging subsystem for injection and recirculation and the low head residual heat removal (RHR) subsystem for recirculation.

The ECCS flow paths consist of 1) piping, valves, heat exchangers, and pumps such that water from the refueling water storage tank (RWST) can be injected via the charging pump into the Reactor Coolant System (RCS) following the accidents described in Bases 3.5.2; and 2) piping, valves, heat exchangers, and pumps such that water from the containment sump can be recirculated to the RCS from the RHR and charging subsystems.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section of Bases 3.5.2 also applies to this Bases section with the following modifications (Refs 2 & 3).

Due to the stable conditions associated with operation in MODE 4 and the reduced probability of occurrence of a Design Basis Accident (DBA), the ECCS operational requirements are reduced. It is understood in these reductions that certain automatic safety injection (SI) actuation is not available. In this MODE, sufficient time exists for manual actuation of the required ECCS to mitigate the consequences of a DBA.

Only one train of ECCS is required for MODE 4. This requirement dictates that single failures are not considered during this MODE of operation. The ECCS trains satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

In MODE 4, one of the two independent (and redundant) ECCS trains is required to be OPERABLE to ensure that sufficient ECCS flow is available to the core following a DBA.

In MODE 4, an ECCS train consists of a centrifugal charging subsystem and an RHR subsystem. Each centrifugal charging subsystem includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST and transferring suction to the discharge of the RHR subsystem. Each RHR subsystem includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the containment sump and recirculating to the RCS.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via a charging pump and its respective supply header. In the long term, the flow path may be switched to take its supply from the containment sump and provide recirculation flow to the RCS.

APPLICABILITY

In MODES 1, 2, and 3, the OPERABILITY requirements for the ECCS are covered by LCO 3.5.2.

In MODE 4, one OPERABLE ECCS train is acceptable without single failure consideration, on the basis of the stable reactivity of the reactor and the limited core cooling requirements.

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, “RCS Loops - MODE 5, Loops Filled,” and LCO 3.4.8, “RCS Loops - MODE 5, Loops Not Filled.” MODE 6 core cooling requirements are addressed by LCO 3.9.5, “Residual Heat Removal (RHR) and Coolant Circulation - High Water Level,” and LCO 3.9.6, “Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level.”

BASES (continued)

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable ECCS high head subsystem when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS high head subsystem and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

With no ECCS RHR subsystem OPERABLE, the plant is not prepared to respond to a loss of coolant accident. The Completion Time of immediately to initiate actions that would restore at least one ECCS RHR subsystem to OPERABLE status ensures that prompt action is taken to restore the required recirculation cooling capacity. Normally, in MODE 4, reactor decay heat is removed from the RCS by an RHR loop. If no RHR loop is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generators. The alternate means of heat removal must continue until the inoperable RHR loop components can be restored to operation so that decay heat removal is continuous.

With both RHR pumps and heat exchangers inoperable for decay heat removal, it would be unwise to require the plant to go to MODE 5, where the only available heat removal system is the RHR. Therefore, the appropriate action is to initiate measures to restore one ECCS RHR subsystem and to continue the actions until the subsystem is restored to OPERABLE status.

The Note allows the required ECCS RHR subsystem to be inoperable due to surveillance testing of RCS Pressure Isolation Valve leakage (2-FCV-74-2 and 2-FCV-74-8). This allows testing while the RCS pressure is high enough to obtain valid leakage data and following valve closure for the RHR decay heat removal path. The condition requiring alternate heat removal methods ensures that the RCS heatup rate can be controlled to prevent Mode 3 entry and thereby ensure that the reduced ECCS operational requirements are maintained. The condition requiring manual realignment capability from the main control room ensures that in the unlikely event of a Design Basis Accident during the 1 hour of Surveillance testing, the RHR subsystem can be placed in ECCS recirculation mode when required to mitigate the event.

(continued)

BASES (continued)

ACTIONS (continued)

B.1

With no ECCS centrifugal charging subsystem OPERABLE, due to the inoperability of the centrifugal charging pump or flow path from the RWST, the plant is not prepared to provide high pressure response to Design Basis Events requiring SI. The 1-hour Completion Time to restore at least one ECCS centrifugal charging subsystem to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the plant in MODE 5, where an ECCS train is not required.

C.1

When the Required Actions of Condition B cannot be completed within the required Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status the plant must be brought to MODE 5 within 24 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant condition in an orderly manner and without challenging plant systems or operators.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance descriptions from Bases 3.5.2 apply for all equipment required to be OPERABLE, specifically SR 3.5.2.1, SR 3.5.2.3, SR 3.5.2.4, SR 3.5.2.7, and SR 3.5.2.8. This SR is modified by a Note that allows an RHR train to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the ECCS mode of operation and not otherwise inoperable. This allows operation in the RHR mode during MODE 4, if necessary.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 35, “Emergency Core Cooling System.”
2. Title 10, Code of Federal Regulations, Part 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plant.”
3. Watts Bar FSAR, Section 6.3, “Emergency Core Cooling System.”

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Refueling Water Storage Tank (RWST)

BASES

BACKGROUND

The RWST supplies borated water to the Chemical and Volume Control System (CVCS) during abnormal operating conditions, to the refueling pool during refueling, and to the ECCS and the Containment Spray System during accident conditions.

The RWST supplies both trains of the ECCS and the Containment Spray System through a common supply header during the injection phase of a loss of coolant accident (LOCA) recovery. Motor operated isolation valves are provided to isolate the RWST from the ECCS once the system has been transferred to the recirculation mode. The recirculation mode is entered when pump suction is transferred to the containment sump following receipt of the RWST-Low coincident with Containment Sump Level-High signal. Use of a single RWST to supply both trains of the ECCS and Containment Spray System is acceptable since the RWST is a passive component, and passive failures are not required to be assumed to occur coincidentally with Design Basis Events until after transfer to the recirculation mode.

The switchover from normal operation to the injection phase of ECCS operation requires changing centrifugal charging pump suction from the CVCS volume control tank (VCT) to the RWST through the use of isolation valves. Each set of isolation valves is interlocked so that the VCT isolation valves will begin to close once the RWST isolation valves are fully open. Since the VCT is under pressure, the preferred pump suction will be from the VCT until the tank is isolated. This will result in a delay in obtaining the RWST borated water. The effects of this delay are discussed in the Applicable Safety Analyses section of these Bases.

During normal operation in MODES 1, 2, and 3, the safety injection (SI) and residual heat removal (RHR) pumps are aligned to take suction from the RWST.

The ECCS and Containment Spray System pumps are provided with recirculation lines that ensure each pump can maintain minimum flow requirements when operating at or near shutoff head conditions.

(continued)

BASES

BACKGROUND (continued)

When the suction for the ECCS and Containment Spray System pumps is transferred to the containment sump, the RWST flow paths must be isolated to prevent a release of the containment sump contents to the RWST, which could result in a release of contaminants to the atmosphere and the eventual loss of suction head for the ECCS pumps.

This LCO ensures that:

a. The RWST contains sufficient borated water to support the ECCS during the injection phase;

b. Sufficient water volume exists in the containment sump to support continued operation of the ECCS and Containment Spray System pumps at the time of transfer to the recirculation mode of cooling; and

c. The reactor remains subcritical following a LOCA.

Insufficient water in the RWST could result in insufficient cooling capacity when the transfer to the recirculation mode occurs. Improper boron concentrations could result in a reduction of SDM or excessive boric acid precipitation in the core following the LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment.

APPLICABLE SAFETY ANALYSES

During accident conditions, the RWST provides a source of borated water to the ECCS and Containment Spray System pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Ref. 1). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, “ECCS - Operating;” B 3.5.3, “ECCS - Shutdown;” and B 3.6.6, “Containment Spray System.” These analyses are used to assess changes to the RWST in order to evaluate their effects in relation to the acceptance limits in the analyses.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

The RWST must also meet volume, boron concentration, and temperature requirements for non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the required volume is a small fraction of the available volume. The deliverable volume limit is set by the LOCA and containment analyses. For the RWST, the deliverable volume is different from the total volume contained since, due to the design of the tank, more water can be contained than can be delivered. The minimum boron concentration is an explicit assumption in the main steam line break (MSLB) analysis to ensure the required shutdown capability. The maximum boron concentration is an explicit assumption in the inadvertent ECCS actuation analysis, although it is typically a non-limiting event and the results are very insensitive to boron concentrations. The maximum temperature ensures that the amount of cooling provided from the RWST during the heatup phase of an MSLB is consistent with safety analysis assumptions; the minimum is an assumption in both the MSLB and inadvertent ECCS actuation analyses, although the inadvertent ECCS actuation event is typically non-limiting.

The MSLB analysis has considered a delay associated with the interlock between the VCT and RWST isolation valves, and the results show that the departure from nucleate boiling design basis is met. The delay has been established as 27 seconds, with offsite power available, or 37 seconds without offsite power.

For a large break LOCA Analysis, the minimum water volume limit of 370,000 gallons and the minimum boron concentration limit are used to compute the post LOCA sump boron concentration necessary to assure subcriticality. This minimum value was chosen to be consistent with the minimum value specified for Unit 1. The large break LOCA is the limiting case since the safety analysis assumes least negative reactivity insertion.

The upper limit on boron concentration of 3300 ppm is used to determine the maximum allowable time to switch to hot leg recirculation following a LOCA. The purpose of switching from cold leg to hot leg injection is to avoid boron precipitation in the core following the accident.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In the ECCS analysis, the containment spray temperature is assumed to be equal to the RWST lower temperature limit of 60°F. If the lower temperature limit is violated, the containment spray further reduces containment pressure, which decreases the rate at which steam can be vented out the break and increases peak clad temperature. The acceptable temperature range of 60°F to 105°F is assumed in the large break LOCA analysis, and the small break analysis value bounds the upper temperature limit of 105°F. The upper temperature limit of 105°F is also used in the containment OPERABILITY analysis. Exceeding the upper temperature limit will result in a higher peak clad temperature, because there is less heat transfer from the core to the injected water following a LOCA and higher containment pressures due to reduced containment spray cooling capacity. For the containment response following an MSLB, the lower limit on boron concentration and the upper limit on RWST water temperature are used to maximize the total energy release to containment.

The RWST satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The RWST ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and to ensure adequate level in the containment sump to support ECCS and Containment Spray System pump operation in the recirculation mode.

To be considered OPERABLE, the RWST must meet the water volume, boron concentration, and temperature limits established in the SRs.

APPLICABILITY

In MODES 1, 2, 3, and 4, RWST OPERABILITY requirements are dictated by ECCS and Containment Spray System OPERABILITY requirements. Since both the ECCS and the Containment Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also be OPERABLE to support their operation. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, “RCS Loops - MODE 5, Loops Filled,” and LCO 3.4.8, “RCS Loops - MODE 5, Loops Not Filled.” MODE 6 core cooling requirements are addressed by LCO 3.9.5, “Residual Heat Removal (RHR) and Coolant Circulation - High Water Level,” and LCO 3.9.6, “Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level.”

BASES (continued)

ACTIONS

A.1

With RWST boron concentration or borated water temperature not within limits, they must be returned to within limits within 8 hours. Under these conditions neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE condition. The 8 hour limit to restore the RWST temperature or boron concentration to within limits was developed considering the time required to change either the boron concentration or temperature and the fact that the contents of the tank are still available for injection.

B.1

With the RWST inoperable for reasons other than Condition A (e.g., water volume), it must be restored to OPERABLE status within 1 hour.

In this Condition, neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains.

C.1 and C.2

If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 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.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST borated water temperature should be verified every 24 hours to be within the limits assumed in the accident analyses band. The specified temperature range is ≥ 60 °F and ≤ 105 °F and does not account for instrument error. The 24 hour Frequency is sufficient to identify a temperature change that would approach either limit and has been shown to be acceptable through operating experience.

The SR is modified by a Note that eliminates the requirement to perform this Surveillance when ambient air temperatures are within the operating limits of the RWST. With ambient air temperatures within the band, the RWST temperature should not exceed the limits.

SR 3.5.4.2

The required minimum RWST water level is ≥ 370,000 gallons (value does not account for instrument error). Verification every 7 days of the presence of this water volume ensures that a sufficient initial supply of water is available for injection and to support continued ECCS and Containment Spray System pump operation on recirculation. Since the RWST volume is normally stable and is protected by an alarm, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience.

SR 3.5.4.3

The boron concentration of the RWST should be verified every 7 days to be within the required limits. This SR ensures that the reactor will remain subcritical following a LOCA. Further, it assures that the resulting sump pH will be maintained in an acceptable range so that boron precipitation in the core will not occur and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. Since the RWST volume is normally stable, a 7 day sampling Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.

REFERENCES

1. Watts Bar FSAR, Section 6.3, “Emergency Core Cooling System,” and Section 15.0, “Accident Analysis.”

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.5 Seal Injection Flow

BASES

BACKGROUND

The function of the seal injection throttle valves during an accident is similar to the function of the ECCS throttle valves in that each restricts flow from the charging pump header to the Reactor Coolant System (RCS).

The restriction on reactor coolant pump (RCP) seal injection flow limits the amount of ECCS flow that would be diverted from the injection path following an accident. This limit is based on safety analysis assumptions that are required because RCP seal injection flow is not isolated during SI.

APPLICABLE SAFETY ANALYSES

All ECCS subsystems are taken credit for in the large break loss of coolant accident (LOCA) at full power (Ref. 1). The LOCA analysis establishes the minimum flow for the ECCS pumps. The centrifugal charging pumps are also credited in the small break LOCA analysis. This analysis establishes the flow and discharge head at the design point for the centrifugal charging pumps. The steam generator tube rupture and main steam line break event analyses also credit the centrifugal charging pumps, but are not limiting in their design. Reference to these analyses is made in assessing changes to the Seal Injection System for evaluation of their effects in relation to the acceptance limits in these analyses.

This LCO ensures that seal injection flow of ≤ 40 gpm, with charging pump discharge header pressure ≥ 2430 psig and pressurizer level control valve full open, will be sufficient for RCP seal integrity but limited so that the ECCS trains will be capable of delivering sufficient water to match boiloff rates soon enough to minimize uncovering of the core following a large LOCA. It also ensures that the centrifugal charging pumps will deliver sufficient water for a small LOCA and sufficient boron to maintain the core subcritical. For smaller LOCAs, the charging pumps alone deliver sufficient fluid to overcome the loss and maintain RCS inventory.

Seal injection flow satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The intent of the LCO limit on seal injection flow is to make sure that flow through the RCP seal water injection line is low enough to ensure that sufficient centrifugal charging pump injection flow is directed to the RCS via the injection points (Ref. 2).

The LCO is not strictly a flow limit, but rather a flow limit based on a flow line resistance. In order to establish the proper flow line resistance, a pressure and flow must be known. The flow line resistance is determined by assuming that the RCS pressure is at normal operating pressure and that the charging pump discharge pressure is greater than or equal to the value specified in this LCO. The charging pump discharge header pressure remains essentially constant through all the applicable MODES of this LCO. A reduction in RCS pressure would result in more flow being diverted to the RCP seal injection line than at normal operating pressure. The valve settings established at the prescribed charging pump discharge header pressure result in a conservative valve position should RCS pressure decrease. The additional modifier of this LCO, the pressurizer level control valve being full open, is required since the valve is designed to fail open for the accident condition. With the discharge pressure and control valve position as specified by the LCO, a flow limit is established. It is this flow limit that is used in the accident analyses.

The limit on seal injection flow, combined with the charging pump discharge header pressure limit and an open wide condition of the pressurizer level control valve, must be met to render the ECCS OPERABLE. If these conditions are not met, the ECCS flow will not be as assumed in the accident analyses.

APPLICABILITY

In MODES 1, 2, and 3, the seal injection flow limit is dictated by ECCS flow requirements, which are specified for MODES 1, 2, 3, and 4. The seal injection flow limit is not applicable for MODE 4 and lower, however, because high seal injection flow is less critical as a result of the lower initial RCS pressure and decay heat removal requirements in these MODES. Therefore, RCP seal injection flow must be limited in MODES 1, 2, and 3 to ensure adequate ECCS performance.

BASES (continued)

ACTIONS

A.1

With the seal injection flow exceeding its limit, the amount of charging flow available to the RCS may be reduced. Under this Condition, action must be taken to restore the flow to below its limit. The operator has 4 hours from the time the flow is known to be above the limit to correctly position the manual valves and thus be in compliance with the accident analysis. The Completion Time minimizes the potential exposure of the plant to a LOCA with insufficient injection flow and provides a reasonable time to restore seal injection flow within limit. This time is conservative with respect to the Completion Times of other ECCS LCOs; it is based on operating experience and is sufficient for taking corrective actions by operations personnel.

B.1 and B.2

When the Required Actions cannot be completed within the required Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 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.

SURVEILLANCE REQUIREMENTS

SR 3.5.5.1

Verification every 31 days that the manual seal injection throttle valves are adjusted to give a flow within the limit listed below ensures that proper manual seal injection throttle valve position, and hence, proper seal injection flow, is maintained:

> ≤ 40 gpm with charging pump discharge header pressure ≥ 2430 psig and the pressurizer level control valve full open (values do not account for instrument error).

The Frequency of 31 days is based on engineering judgment and is consistent with other ECCS valve Surveillance Frequencies. The Frequency has proven to be acceptable through operating experience.

As noted, the Surveillance is not required to be performed until 4 hours after the RCS pressure has stabilized within a ± 20 psig range of normal operating pressure. The RCS pressure requirement is specified since this configuration will produce the required pressure conditions necessary to assure that the manual valves are set correctly. The exception is limited to 4 hours to ensure that the Surveillance is timely.

BASES

REFERENCES

1. Watts Bar FSAR, Section 6.3, “Emergency Core Cooling System,” and Section 15.0, “Accident Analysis.”

2. Title 10, Code of Federal Regulations, Part 50.46, “Acceptance Criteria for Emergency Core Cooling Systems for Light-Water Nuclear Plants,” 1974.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment is a free standing steel pressure vessel surrounded by a reinforced concrete shield building. The containment vessel, including all its penetrations, is a low leakage steel shell designed to contain the radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). Additionally, the containment and shield building provide shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment vessel is a vertical cylindrical steel pressure vessel with hemispherical dome and a concrete base mat with steel membrane. It is completely enclosed by a reinforced concrete shield building. An annular space exists between the walls and domes of the steel containment vessel and the concrete shield building to provide for the collection, mixing, holdup, and controlled release of containment out leakage. Ice condenser containments utilize an outer concrete building for shielding and an inner steel containment for leak tightness.

Containment piping penetration assemblies provide for the passage of process, service, sampling, and instrumentation pipelines into the containment vessel while maintaining containment integrity. The shield building provides shielding and allows controlled filtered release of the annulus atmosphere under accident conditions, as well as environmental missile protection for the containment vessel and Nuclear Steam Supply System.

The inner steel containment and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 leakage rate requirements comply with 10 CFR 50, Appendix J, Option B (Ref. 1), as modified by approved exemptions.

(continued)

BASES

BACKGROUND (continued)

The isolation devices for the penetrations in the containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

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

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

   2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, “Containment Isolation Valves.”

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, “Containment Air Locks.”

c. All equipment hatches are closed.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rates.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss of coolant accident (LOCA), a steam line break (SLB), and a rod ejection accident (REA) (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA or REA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.25% of containment air weight per day (Ref. 3). This leakage rate, used in the evaluation of offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) related to the design basis LOCA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.25% per day in the safety analysis at P_a = 15.0 psig which bounds the calculated peak containment internal pressure resulting from the limiting design basis LOCA (Ref. 3).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first start up after performing a required Containment Leakage Rate Testing Program leakage test. At this time, applicable leakage limits must be met.

Compliance with this LCO will ensure a containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

Individual leakage rates specified for the containment air lock (LCO 3.6.2), purge valves with resilient seals, and Shield Building containment bypass leakage (LCO 3.6.3) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J, Option B. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the acceptance criteria of Appendix J, Option B.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, containment is not required to be OPERABLE in MODES 5 and 6 to prevent leakage of radioactive material from containment.

BASES (continued)

ACTIONS

A.1

In the event containment is inoperable, containment must be restored to OPERABLE status within 1 hour. The 1-hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment OPERABLE during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods when containment is inoperable is minimal.

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock, Shield Building containment bypass leakage path, and purge valve with resilient seal leakage limits specified in LCO 3.6.2 and LCO 3.6.3 does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the first startup after performing a required leakage test is required to be $< 0.6\ L_a$ for combined Type B and C leakage and $\leq 0.75\ L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis.

SR Frequencies are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix J, Option B, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors - Performance-Based Requirements.”

2. Watts Bar FSAR, Section 15.0, “Accident Analysis.”

3. Watts Bar FSAR, Section 6.2, “Containment Systems.”

4. Regulatory Guide 1.163, “Performance-Based Containment Leak-Test Program,” September 1995.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is nominally a right circular cylinder, 8 ft 7 inches in diameter, with a door at each end. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

Each personnel air lock is provided with limit switches on both doors that provide control room indication of door position.

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the plant safety analyses.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The DBAs that result in a significant release of radioactive material within containment are a loss of coolant accident and a rod ejection accident (Ref. 2). In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate (L_a) of 0.25% of containment air weight per day (Ref. 2), at the calculated peak containment pressure of 15.0 psig. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Each containment air lock forms part of the containment pressure boundary. As part of containment pressure boundary, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into and exit from containment.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODES 5 and 6 to prevent leakage of radioactive material from containment.

BASES (continued)

ACTIONS

The ACTIONS are modified by a Note that allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. It is preferred that the air lock be accessed from inside containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be performed from the barrel side of the door, then it is permissible to enter the air lock through the OPERABLE door which means there is a short time during which the containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed.

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

In the event the air lock leakage results in exceeding the overall containment leakage rate, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, “Containment.”

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

With one air lock door in one or more containment air locks inoperable, the OPERABLE door must be verified closed (Required Action A.1) in each affected containment air lock. This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is reasonable for locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

(continued)

BASES

ACTIONS

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

Required Action A.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed 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 the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls if both air locks have an inoperable door.

This 7 day restriction begins when the second air lock is discovered inoperable. Containment entry may be required on a periodic basis to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-required activities) if the containment is entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the containment during the short time that the OPERABLE door is expected to be open.

(continued)

BASES

ACTIONS (continued)

B.1, B.2, and B.3

With an air lock interlock mechanism inoperable in one or more air locks, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed 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 the door, once it has been verified to be in the proper position, is small.

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

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

(continued)

BASES

ACTIONS

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

Additionally, the affected air lock must be restored to OPERABLE status within the 24 hour Completion Time. The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock.

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is required by the Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 requires the results of the air lock leakage tests to be evaluated against the acceptance criteria of the Containment Leakage Rate Testing Program, 5.7.2.19. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.2.2

The air lock interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and outer doors will not inadvertently occur.

Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is only challenged when the containment air lock door is opened, this test is only required to be performed upon entering or exiting a containment air lock but is not required more frequently than every 184 days. The 184 day Frequency is based on engineering judgment and is considered adequate in view of other indications of door status available to operations personnel and because the interlock is only disabled in MODES 5 and 6.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix J, Option B, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors - Performance-Based Requirements.”

2. Watts Bar FSAR, Section 6.2.4.2.3, “Penetration Design.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on a containment isolation signal or which are normally closed. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System.

Automatic isolation signals are produced during accident conditions. Containment Phase “A” isolation occurs upon receipt of a safety injection signal. The Phase “A” isolation signal isolates non-essential process lines in order to minimize leakage of fission product radioactivity. Containment Phase “B” isolation occurs upon receipt of a containment pressure – High High signal and isolates the remaining process lines, except systems required for accident mitigation. In addition to the isolation signals listed above, the purge and exhaust valves receive an isolation signal on a containment high radiation condition. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the environment in the event of a release of fission product radioactivity to the containment atmosphere as a result of a Design Basis Accident (DBA).

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

(continued)

BASES

BACKGROUND (continued)

Reactor Building Purge Ventilation System

The Reactor Building Purge Ventilation system operates to supply outside air into the containment for ventilation and cooling or heating, to equalize internal and external pressures and to reduce the concentration of noble gases within containment prior to and during personnel access. The supply and exhaust lines each contain two isolation valves. Because of their large size and their exposure to higher containment pressure during accident conditions, the 24 inch containment lower compartment purge isolation valves are physically restricted to ≤ 50 degrees open.

Since the valves used in the Reactor Building Purge Ventilation System are designed to meet the requirements for automatic containment isolation valves, these valves may be opened as needed in MODES 1, 2, 3 and 4.

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the safety analysis of any event requiring isolation of containment is applicable to this LCO.

The DBAs that result in a significant release of radioactive material within containment are a loss of coolant accident (LOCA) and a rod ejection accident (Ref. 1). In the analyses for each of these accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves (including containment purge valves) are minimized.

The DBA analysis assumes that, within 60 seconds after the accident, isolation of the containment is complete and leakage terminated except for the design leakage rate (L_a) and for valves in the Essential Raw Cooling Water (ERCW) system and Component Cooling System (CSS). These valves are in liquid containing systems and have been evaluated to have no impact on the DBA analysis. The containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and containment isolation valve stroke times.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The single failure criterion required to be imposed in the conduct of plant safety analyses was considered in the original design of the containment purge valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred. The inboard and outboard isolation valves on each line are provided with redundant control and power trains, pneumatically operated to open, and spring-loaded to close upon power loss or air failure. This arrangement was designed to preclude common mode failures from disabling both valves on a purge line.

The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valves' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 24 inch containment lower compartment purge valves must have blocks installed to prevent full opening. Blocked purge valves also actuate on an automatic signal. The valves covered by this LCO are listed along with their associated stroke times in the FSAR (Ref. 2). The normally closed containment isolation valves are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact. These passive isolation valves/devices are those listed in Reference 2.

Purge valves with resilient seals and shield building bypass valves meet additional leakage rate requirements. The other containment isolation valve leakage rates are addressed by LCO 3.6.1, “Containment,” as Type C testing.

This LCO provides assurance that the containment isolation valves will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator (licensed or unlicensed) at the valve controls, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated. For valve controls located in the control room, an operator (other than the Shift Operations Supervisor, Assistant Shift Operations Supervisor, or the Operator at the Controls) may monitor containment isolation signal status rather than be stationed at the valve controls. Other secondary responsibilities which do not prevent adequate monitoring of containment isolation signal status may be performed by the operator provided his/her primary responsibility is rapid isolation of the penetration when needed for containment isolation. Use of the Unit Control Room Operator (CRO) to perform this function should be limited to those situations where no other operator is available.

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

The ACTIONS are further modified by third Note, which ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation valve.

In the event the isolation valve leakage results in exceeding the overall containment leakage rate, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths is inoperable except for purge valve or shield building bypass leakage not within limit, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of “Once per 31 days for isolation devices outside containment” is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as “Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days” is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two containment isolation valves. For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides the appropriate actions.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

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

B.1

With two containment isolation valves in one or more penetration flow paths inoperable, 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. 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. In the event the affected penetration is isolated in accordance with Required Action B.1, the affected penetration must be verified to be isolated on a periodic basis per Required Action A.2, which remains in effect. This periodic verification is necessary to assure leak tightness of containment and that penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative control and the probability of their misalignment is low. Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two containment isolation valves. Condition A of this LCO addresses the condition of one containment isolation valve inoperable in this type of penetration flow path.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve flow path 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 flow path. Required Action C.1 must be completed within the 4-hour Completion Time. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. In the event the affected penetration flow path 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 periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve and a closed system. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system. Required Action C.2 is modified by two Notes. Note 1 applies to valves and blind flanges located in high radiation areas, and allow these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

(continued)

BASES

ACTIONS (continued)

D.1

With the shield building bypass leakage rate not within limit, the assumptions of the safety analyses are not met. Therefore, the leakage must be restored to within limit within 4 hours. Restoration can be accomplished by isolating the penetration(s) that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two 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(s) and the relative importance of shield building bypass leakage to the overall containment function.

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

In the event one or more containment purge valves in one or more penetration flow paths are not within the purge valve leakage limits, purge valve leakage must be restored to within limits, or the affected penetration flow path must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, closed manual valve, or blind flange. A purge valve with resilient seals utilized to satisfy Required Action E.1 must have been demonstrated to meet the leakage requirements of SR 3.6.3.5. The specified Completion Time is reasonable, considering that one containment purge valve remains closed so that a gross breach of containment does not exist.

In accordance with Required Action E.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside containment potentially capable of being mispositioned are in the correct position. For the isolation devices inside containment, the time period specified as “Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days” is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

(continued)

BASES

ACTIONS

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

For the containment purge valve with resilient seal that is isolated in accordance with Required Action E.1, SR 3.6.3.5 must be performed at least once every 92 days. This assures that degradation of the resilient seal is detected and confirms that the leakage rate of the containment purge valve does not increase during the time the penetration is isolated. The normal Frequency for SR 3.6.3.5, 184 days, is based on an NRC initiative, Generic Issue B-20 (Ref. 3). Since more reliance is placed on a single valve while in this Condition, it is prudent to perform the SR more often. Therefore, a Frequency of once per 92 days was chosen and has been shown to be acceptable based on operating experience.

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

F.1 and F.2

If the Required Actions and associated Completion Times 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 6 hours and to MODE 5 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.1

This SR ensures that the purge valves are closed as required or, if open, open for an allowable reason. If a purge valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is not required to be met when the purge valves are open for the reasons stated. The valves may be opened for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. All purge valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The 31-day Frequency is consistent with other containment isolation valve requirements discussed in SR 3.6.3.2.

SR 3.6.3.2

This SR requires verification that each containment isolation manual valve and blind flange located outside containment, the containment annulus, and the Main Steam Valve Vault Rooms, and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those containment isolation valves in areas where the valves are capable of being mispositioned are in the correct position. Since verification of valve position for these valves is relatively easy, the 31 day Frequency is based on engineering judgment and was chosen to provide added assurance of the correct positions. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located inside containment, the containment annulus, and the Main Steam Valve Vault Rooms, and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For these containment isolation valves, the Frequency of "Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate since these containment isolation valves are operated under administrative controls (e.g., locked valve program) and may be verified by administrative means, because the probability of their misalignment is low. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

The Note allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position, is small.

SR 3.6.3.4

Verifying that the isolation time of each power operated and automatic containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are in accordance with the Inservice Testing Program or 92 days.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.5

For containment purge valves with resilient seals, additional leakage rate testing beyond the test requirements of 10 CFR 50, Appendix J, Option B (Ref. 4), is required to ensure OPERABILITY.

Operating experience has demonstrated that this type of seal has the potential to degrade in a shorter time period than do other seal types. Based on this observation and the importance of maintaining this penetration leak tight (due to the direct path between containment and the environment), a Frequency of 184 days was established as part of the NRC resolution of Generic Issue B-20, “Containment Leakage Due to Seal Deterioration” (Ref. 3).

Additionally, this SR must be performed within 92 days after opening the valve. The 92-day Frequency was chosen recognizing that cycling the valve could introduce additional seal degradation (beyond that occurring to a valve that has not been opened). Thus, decreasing the interval (from 184 days) is a prudent measure after a valve has been opened.

SR 3.6.3.6

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative control. The 18-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Operating experience has shown that these components usually pass this Surveillance when performed at the 18-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.7

Verifying that each 24 inch containment lower compartment purge valve is blocked to restrict opening to ≤ 50° is required to ensure that the valves can close under DBA conditions within the times assumed in the analyses of References 1 and 2. If a LOCA occurs, the purge valves must close to maintain containment leakage within the values assumed in the accident analysis. At other times when containment pressurization concerns are not present, 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.

SR 3.6.3.8

This SR ensures that the combined leakage rate of all Shield Building bypass leakage paths is less than or equal to the specified leakage rate. This provides assurance that the assumptions in the safety analysis are met. The as left bypass leakage rate prior to the first startup after performing a leakage test, requires calculation using maximum pathway leakage (leakage through the worse of the two isolation valves). If the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange, then the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. At all other times, the leakage rate will be calculated using minimum pathway leakage.

The frequency is required by the Containment Leakage Rate Testing Program. This SR simply imposes additional acceptance criteria. Although not a part of L_a, the Shield Building Bypass leakage path combined leakage rate is determined using the 10 CFR 50, Appendix J, Option B, Type B and C leakage rates for the applicable barriers.

BASES

REFERENCES

1. Watts Bar FSAR, Section 15.0, “Accident Analysis.”

2. Watts Bar FSAR, Section 6.2.4.2, “Containment Isolation System Design,” and Table 6.2.4-1, “Containment Penetrations and Barriers.”

3. Generic Issue B-20, “Containment Leakage Due to Seal Deterioration.”

4. Title 10, Code of Federal Regulations, Part 50 Appendix J, Option B, “Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors - Performance - Based Requirements.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential (-2.0 psid) with respect to the shield building annulus atmosphere in the event of inadvertent actuation of the Containment Spray System or Air Return Fans.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer pressure transients. The worst case LOCA generates larger mass and energy release than the worst case SLB. Thus, the LOCA event bounds the SLB event from the containment peak pressure standpoint (Ref. 1).

The initial pressure condition used in the containment analysis was 15.0 psia. This resulted in a maximum peak containment pressure from a LOCA of 12.40 psig. The containment analysis (Ref. 1) shows that the maximum allowable internal containment pressure, P_a (15.0 psig), bounds the calculated results from the limiting LOCA. The maximum containment pressure resulting from the worst case LOCA does not exceed the maximum allowable calculated containment pressure of 15.0 psig.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The containment was also designed for an external pressure load equivalent to 2.0 psig. The inadvertent actuation of the Containment Spray System was analyzed to determine the resulting reduction in containment pressure. The initial pressure condition used in this analysis was -0.1 psig. This resulted in a minimum pressure inside containment of 1.4 psig, which is less than the design load.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. Therefore, for the reflood phase, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50, Appendix K (Ref. 2).

Containment pressure satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit ensures that the containment will not exceed the design negative differential pressure following the inadvertent actuation of the Containment Spray System or Air Return Fans.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analyses are maintained, the LCO is applicable in MODES 1, 2, 3 and 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODES 5 or 6.

BASES

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, it must be restored to within these limits within 1 hour. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If containment pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that containment pressure is within limits (≥ -0.1 and ≤ +0.3 psid relative to the annulus, value does not account for instrument error) ensures that plant operation remains within the limits assumed in the containment analysis. The 12 hour Frequency of this SR was developed based on operating experience related to trending of containment pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment pressure condition.

REFERENCES

1. Watts Bar FSAR, Section 6.2.2, "Containment Heat Removal Systems."

2. Title 10, Code of Federal Regulations, Part 50, Appendix K, "ECCS Evaluation Models."

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Air Temperature

BASES

BACKGROUND

The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment average air temperature is limited, during normal operation, to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB).

The containment average air temperature limit is derived from the input conditions used in the containment functional analyses and the containment structure external pressure analyses. This LCO ensures that initial conditions assumed in the analysis of containment response to a DBA are not violated during plant operations. The total amount of energy removed from containment by the Containment Spray and Cooling systems during post accident conditions is dependent upon the energy released to the containment due to the event, as well as the initial containment temperature and pressure.

APPLICABLE SAFETY ANALYSES

Containment average air temperature is an initial condition used in the DBA analyses that establishes the containment environmental qualification operating envelope for both pressure and temperature. The limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analyses for containment (Ref. 1).

The limiting DBAs considered relative to containment OPERABILITY are the LOCA and SLB. The DBA LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to Engineered Safety Feature (ESF) systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train each of Containment Spray System, Residual Heat Removal System, and Air Return System being rendered inoperable.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting DBA for the maximum peak containment air temperature is an SLB. For the upper compartment, the initial containment average air temperature assumed in this design basis analyses (Ref. 2) is 85 °F. For the lower compartment, the initial average containment air temperature assumed in this design basis analyses is 120 °F. These temperatures result in a maximum containment air temperature.

The higher temperature limits are also considered in the depressurization analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Containment Spray System for both containment compartments.

The limiting DBA for establishing the maximum peak containment internal pressure is a LOCA. The upper temperature limits, 110 °F for the upper compartment and 120 °F for the lower compartment, are used in this analysis to ensure that, in the event of an accident, the maximum containment internal pressure will not be exceeded in either containment compartment.

Containment average air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

During a DBA, with an initial containment average air temperature within the LCO temperature limits, the resultant peak accident temperature is maintained below the containment design temperature. As a result, the ability of containment to perform its design function is ensured. In MODES 2, 3 and 4, containment air temperature may be as low as 60 °F (value does not account for instrument error) because the resultant calculated peak containment accident pressure would not exceed the design pressure due to a lesser amount of energy released from the pipe break in these MODES (Ref. 3).

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODE 5 or 6.

BASES (continued)

ACTIONS

A.1

When containment average air temperature in the upper or lower compartment is not within the limit of the LCO, the average air temperature in the affected compartment must be restored to within limits within 8 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 8-hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems.

B.1 and B.2

If the containment average air temperature cannot be restored to within its limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1 and SR 3.6.5.2

LCO 3.6.5 specifies that the containment average air temperature shall be the following values which do not account for instrument error:

a. $\geq$ 85 °F and $\leq$ 110 °F for the containment upper compartment, and

b. $\geq$ 100 °F and $\leq$ 120 °F for the containment lower compartment.

Verifying that containment average air temperature is within the LCO limits ensures that containment operation remains within the limits assumed for the containment analyses. In order to determine the containment average air temperature, a weighted average is calculated using measurements taken at locations within the containment selected to provide a representative sample of the overall containment atmosphere. The 24-hour Frequency of these SRs is considered acceptable based on observed slow rates of temperature increase within containment as a result of environmental heat sources (due to the large volume of containment). Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment temperature condition.

BASES

REFERENCES

1. Watts Bar FSAR, Section 6.2, “Containment Systems.”

2. Watts Bar System Description N3-30RB-4002R5, “Reactor Building Ventilation System.”

3. Westinghouse Letter WAT-D-10698, dated November 23, 1999.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray System

BASES

BACKGROUND

The Containment Spray System provides containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure helps reduce the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA). The Containment Spray System is designed to meet the requirements of 10 CFR 50, Appendix A, GDC 38, “Containment Heat Removal,” GDC 39, “Inspection of Containment Heat Removal Systems,” and GDC 40, “Testing of Containment Heat Removal Systems,” (Ref. 1).

The Containment Spray System consists of two separate trains of equal capacity, each capable of meeting the system design basis spray coverage. Each train includes a containment spray pump, one containment spray heat exchanger, a spray header, nozzles, valves, and piping. Each train is powered from a separate Engineered Safety Feature (ESF) bus. The refueling water storage tank (RWST) supplies borated water to the Containment Spray System during the injection phase of operation. In the recirculation mode of operation, containment spray pump suction is transferred from the RWST to the containment recirculation sump.

The diversion of a portion of the recirculation flow from each train of the Residual Heat Removal (RHR) System to additional redundant spray headers completes the Containment Spray System heat removal capability. Each RHR train is capable of supplying spray coverage, if required, to supplement the Containment Spray System.

The Containment Spray System and RHR System provide a spray of subcooled borated water into the upper region of containment to limit the containment pressure and temperature during a DBA. In the recirculation mode of operation, heat is removed from the containment sump water by the Containment Spray System and RHR heat exchangers. Each train of the Containment Spray System, supplemented by a train of RHR spray, provides adequate spray coverage to meet the system design requirements for containment heat removal.

(continued)

BASES

BACKGROUND (continued)

The Containment Spray System is actuated either automatically by a containment High-High pressure signal or manually. An automatic actuation starts the two containment spray pumps, opens the containment spray pump discharge valves, and begins the injection phase. A manual actuation of the Containment Spray System requires the operator to actuate two separate switches on the main control board to begin the same sequence. The injection phase continues until an RWST level Low-Low alarm is received. The Low-Low alarm for the RWST signals the operator to manually align the system to the recirculation mode. The Containment Spray System in the recirculation mode maintains an equilibrium temperature between the containment atmosphere and the recirculated sump water. Operation of the Containment Spray System in the recirculation mode is controlled by the operator in accordance with the emergency operating procedures.

The RHR spray operation is initiated manually, when required by the emergency operating procedures, after the Emergency Core Cooling System (ECCS) is operating in the recirculation mode. The RHR sprays are available to supplement the Containment Spray System, if required, in limiting containment pressure. This additional spray capacity would typically be used after the ice bed has been depleted and in the event that containment pressure rises above a pre-determined limit.

The Containment Spray System is an ESF system. It is designed to ensure that the heat removal capability required during the post accident period can be attained.

The operation of the ice condenser is adequate to assure pressure suppression during the initial blowdown of steam and water from a DBA. During the post blowdown period, the Air Return System (ARS) is automatically started. The ARS returns upper compartment air through the divider barrier to the lower compartment. This serves to equalize pressures in containment and to continue circulating heated air and steam through the ice condenser, where heat is removed by the remaining ice and by the Containment Spray System after the ice has melted.

The Containment Spray System limits the temperature and pressure that could be expected following a DBA. Protection of containment integrity limits leakage of fission product radioactivity from containment to the environment.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The limiting DBAs considered relative to containment are the loss of coolant accident (LOCA) and the steam line break (SLB). The DBA LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed, in regard to containment ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train of the Containment Spray System, the RHR System, and the ARS being rendered inoperable (Ref. 2).

The DBA analyses show that the maximum peak containment pressure of 12.40 psig results from the LOCA analysis, and is calculated to be less than the containment maximum allowable pressure of 15 psig. The maximum peak containment atmosphere temperature results from the SLB analysis. The calculated transient containment atmosphere temperatures are acceptable for the DBA SLB.

The modeled Containment Spray System actuation from the containment analysis is based on a response time associated with exceeding the containment High-High pressure signal setpoint to achieving full flow through the containment spray nozzles. A delayed response time initiation provides conservative analyses of peak calculated containment temperature and pressure responses. The Containment Spray System total response time of 234 seconds is composed of signal delay, diesel generator startup, and system startup time.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the ECCS cooling effectiveness during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures in accordance with 10 CFR 50, Appendix K (Ref. 3).

Inadvertent actuation of the Containment Spray System is evaluated in the analysis, and the resultant reduction in containment pressure is calculated. The maximum calculated steady state pressure differential relative to the Shield Building annulus is 1.4 psid, which is below the containment design external pressure load of 2.0 psid.

The Containment Spray System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

During a DBA, one train of Containment Spray System and RHR Spray System is required to provide the heat removal capability assumed in the safety analyses. To ensure that these requirements are met, two containment spray trains and two RHR spray trains must be OPERABLE with power from two safety related, independent power supplies. Therefore, in the event of an accident, at least one train in each system operates.

Each containment spray train typically includes a spray pump, header, valves, a heat exchanger, nozzles, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal and transferring suction to the containment sump. This suction path realignment is accomplished by manual operator action upon receipt of a Low-Low level alarm for the RWST.

Each RHR spray train includes a pump, header, valves, a heat exchanger, nozzles, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the containment sump and supplying flow to the spray header.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature requiring the operation of the Containment Spray System. A Note has been added which states the RHR spray trains are not required in MODE 4. The containment spray system does not require supplemental cooling from the RHR spray in MODE 4.

In MODES 5 and 6, the probability and consequences of these events are reduced because of the pressure and temperature limitations of these MODES. Thus, the Containment Spray System is not required to be OPERABLE in MODE 5 or 6.

ACTIONS

A.1 and B.1

With one containment spray train and/or RHR spray train inoperable, the affected train must be restored to OPERABLE status within 72 hours. The components in this degraded condition are capable of providing 100% of the heat removal needs after an accident. The 72-hour Completion Time was developed taking into account the redundant heat removal capabilities afforded by the OPERABLE train and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the affected containment spray train and/or RHR spray train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 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 extended interval to reach MODE 5 allows additional time and is reasonable when considering that the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment of manual, power operated, and automatic valves, excluding check valves, in the Containment Spray System provides assurance that the proper flow path exists for Containment Spray System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since they were verified in the correct position prior to being secured. This SR does not require any testing or valve manipulation. Rather, it involves verification that those valves outside containment and capable of potentially being mis-positioned, are in the correct position.

SR 3.6.6.2

Verifying that each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head ensures that spray pump performance has not degraded during the cycle. Flow and differential head are normal tests of centrifugal pump performance required by the American Society of Mechanical Engineers (ASME) OM Code (Ref. 4). Since the containment spray pumps cannot be tested with flow through the spray headers, they are tested on bypass flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this SR is in accordance with the Inservice Testing Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.3 and SR 3.6.6.4

These SRs require verification that each automatic containment spray valve actuates to its correct position and each containment spray pump starts upon receipt of an actual or simulated containment spray actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative control. Containment spray pump start verification may be performed by testing breaker actuation without pump start (breaker is racked out in its "test position") and observation of the local or remote pump start lights (breaker energization light). The 18-month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillances were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillances when performed at the 18-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

A single surveillance may be used to satisfy both the valve and pump requirements.

SR 3.6.6.5

With the containment spray inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through test connections. This SR ensures that each spray nozzle required by the design bases is unobstructed and that spray coverage of the containment during an accident is not degraded. Because of the passive design of the nozzle, a test at the first refueling and at 10 year intervals are considered adequate to detect obstruction of the spray nozzles.

SR 3.6.6.6

The Surveillance descriptions from Bases 3.5.2 for SR 3.5.2.2 and SR 3.5.2.4 apply as applicable to the RHR spray system.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, “General Design Criterion (GDC) 38, “Containment Heat Removal,” GDC 39, “Inspection of Containment Heat Removal System,” GDC 40, “Testing of Containment Heat Removal Systems, and GDC 50, “Containment Design Basis.”

2. NPG-SDD-WBN2-72-4001, “Containment Heat Removal Spray System.”

3. Title 10, Code of Federal Regulations, Part 50, Appendix K, “ECCS Evaluation Models.”

4. American Society of Mechanical Engineers (ASME) OM Code, “Code for Operation and Maintenance of Nuclear Power Plants.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 RESERVED FOR FUTURE ADDITION

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Hydrogen Mitigation System (HMS)

BASES

BACKGROUND

The HMS consists of two groups of 34 igniters distributed throughout the containment. The HMS reduces the potential for breach of primary containment due to a hydrogen oxygen reaction in post accident environments. The HMS is required by 10 CFR 50.44, “Standards for Combustible Gas Control Systems in Light-Water-Cooled Reactors” (Ref. 1), and Appendix A, GDC 41, “Containment Atmosphere Cleanup” (Ref. 2), to reduce the hydrogen concentration in the primary containment following a degraded core accident. The HMS must be capable of handling an amount of hydrogen equivalent to that generated from a metal water reaction involving 75% of the fuel cladding surrounding the active fuel region (excluding the plenum volume).

10 CFR 50.44 (Ref. 1) requires plants with ice condenser containments to install suitable hydrogen control systems that would accommodate an amount of hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water. The HMS provides this required capability. This requirement was placed on ice condenser plants because of their small containment volume and low design pressure (compared with pressurized water reactor dry containments). Calculations indicate that if hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water were to collect in the primary containment, the resulting hydrogen concentration would be far above the lower flammability limit such that, if ignited from a random ignition source, the resulting hydrogen burn would seriously challenge the containment and safety systems in the containment.

The HMS is based on the concept of controlled ignition using thermal igniters, designed to be capable of functioning in a post accident environment, seismically supported, and capable of actuation from the control room. A total of 68 igniters are distributed throughout the various regions of containment in which hydrogen could be released or to which it could flow in significant quantities. The igniters are arranged in two independent trains such that each containment region has at least two igniters, one from each train, controlled and powered redundantly so that ignition would occur in each region even if one train failed to energize.

(continued)

BASES

BACKGROUND (continued)

When the HMS is initiated, the igniter elements are energized and heat up to a surface temperature ≥ 1700 °F. At this temperature, they ignite the hydrogen gas that is present in the airspace in the vicinity of the igniter. The HMS depends on the dispersed location of the igniters so that local pockets of hydrogen at increased concentrations would burn before reaching a hydrogen concentration significantly higher than the lower flammability limit. Hydrogen ignition in the vicinity of the igniters is assumed to occur when the local hydrogen concentration reaches a minimum 5.0 volume percent (v/o).

APPLICABLE SAFETY ANALYSES

The HMS causes hydrogen in containment to burn in a controlled manner as it accumulates following a degraded core accident (Ref. 3). Burning occurs at the lower flammability concentration, where the resulting temperatures and pressures are relatively benign. Without the system, hydrogen could build up to higher concentrations that could result in a violent reaction if ignited by a random ignition source after such a buildup.

The hydrogen igniters are not included for mitigation of a Design Basis Accident (DBA) because an amount of hydrogen equivalent to that generated from the reaction of 75% of the fuel cladding with water is far in excess of the hydrogen calculated for the limiting DBA loss of coolant accident (LOCA). The hydrogen igniters have been shown by probabilistic risk analysis to be a significant contributor to limiting the severity of accident sequences that are commonly found to dominate risk for plants with ice condenser containments. As such, the hydrogen igniters are considered to be risk significant in accordance with 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

Two HMS trains must be OPERABLE with power from two independent, safety related power supplies.

For this plant, an OPERABLE HMS train consists of 33 of 34 igniters energized on the train.

Operation with at least one HMS train ensures that the hydrogen in containment can be burned in a controlled manner. Unavailability of both HMS trains could lead to hydrogen buildup to higher concentrations, which could result in a violent reaction if ignited. The reaction could take place fast enough to lead to high temperatures and overpressurization of containment and, as a result, breach containment or cause containment leakage rates above those assumed in the safety analyses. Damage to safety related equipment located in containment could also occur.

APPLICABILITY

Requiring OPERABILITY in MODES 1 and 2 for the HMS ensures its immediate availability after safety injection and scram actuated on a LOCA initiation. In the post accident environment, the two HMS subsystems are required to control the hydrogen concentration within containment to near its flammability limit of 4.0 v/o assuming a worst case single failure. This prevents overpressurization of containment and damage to safety related equipment and instruments located within containment.

In MODES 3 and 4, both the hydrogen production rate and the total hydrogen production after a LOCA would be significantly less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the HMS is low. Therefore, the HMS is not required in MODES 3 and 4.

In MODES 5 and 6, the probability and consequences of a LOCA are reduced due to the pressure and temperature limitations of these MODES. Therefore, the HMS is not required to be OPERABLE in MODES 5 and 6.

BASES (continued)

ACTIONS

A.1 and A.2

With one HMS train inoperable, the inoperable train must be restored to OPERABLE status within 7 days or the OPERABLE train must be verified OPERABLE frequently by performance of SR 3.6.8.1. The 7-day Completion Time is based on the low probability of the occurrence of a degraded core event that would generate hydrogen in amounts equivalent to a metal water reaction of 75% of the core cladding, the length of time after the event that operator action would be required to prevent hydrogen accumulation from exceeding this limit, and the low probability of failure of the OPERABLE HMS train. Alternative Required Action A.2, by frequent surveillances, provides assurance that the OPERABLE train continues to be OPERABLE.

B.1

Condition B is one containment region with no OPERABLE hydrogen igniter. Thus, while in Condition B, or in Conditions A and B simultaneously, there would always be ignition capability in the adjacent containment regions that would provide redundant capability by flame propagation to the region with no OPERABLE igniters.

Required Action B.1 calls for the restoration of one hydrogen igniter in each region to OPERABLE status within 7 days. The 7-day Completion Time is based on the same reasons given under Required Action A.1.

C.1

If the HMS subsystem(s) cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1

This SR confirms that ≥ 33 of 34 hydrogen igniters can be successfully energized in each train. The igniters are simple resistance elements. Therefore, energizing provides assurance of OPERABILITY. The allowance of one inoperable hydrogen igniter is acceptable because, although one inoperable hydrogen igniter in a region would compromise redundancy in that region, the containment regions are interconnected so that ignition in one region would cause burning to progress to the others (i.e., there is overlap in each hydrogen igniter's effectiveness between regions). The Frequency of 92 days has been shown to be acceptable through operating experience.

SR 3.6.8.2

This SR confirms that the two inoperable hydrogen igniters allowed by SR 3.6.8.1 (i.e., one in each train) are not in the same containment region. The containment regions and hydrogen igniter locations are provided in Reference 3. The Frequency of 92 days is acceptable based on the Frequency of SR 3.6.8.1, which provides the information for performing this SR.

SR 3.6.8.3

A more detailed functional test is performed every 18 months to verify system OPERABILITY. Each igniter (glow plug) is visually examined to ensure that it is clean and that the electrical circuitry is energized. All igniters, including normally inaccessible igniters, are visually checked for a glow to verify that they are energized. Additionally, the surface temperature of each glow plug is measured to be ≥ 1700 °F to demonstrate that a temperature sufficient for ignition is achieved. 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 SR when performed at the 18-month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50.44, “Standards for Combustible Gas Control Systems in Light Water-Cooled Power Reactors.”

2. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 41, “Containment Atmosphere Cleanup.”

3. Watts Bar FSAR, Section 6.2.5A, “Hydrogen Mitigation System Description.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.9 Emergency Gas Treatment System (EGTS)

BASES

BACKGROUND

The EGTS is required by 10 CFR 50, Appendix A, GDC 41, “Containment Atmosphere Cleanup” (Ref. 1), to ensure that radioactive materials that leak from the primary containment into the shield building (secondary containment) following a Design Basis Accident (DBA) are filtered and adsorbed prior to exhausting to the environment.

The containment has a secondary containment called the shield building, which is a concrete structure that surrounds the steel primary containment vessel. Between the containment vessel and the shield building inner wall is an annular space that collects any containment leakage that may occur following a loss of coolant accident (LOCA). This space also allows for periodic inspection of the outer surface of the steel containment vessel.

The EGTS establishes a negative pressure in the annulus between the shield building and the steel containment vessel. Filters in the system then control the release of radioactive contaminants to the environment. Shield building OPERABILITY is required to ensure retention of primary containment leakage and proper operation of the EGTS.

The EGTS consists of two separate and redundant trains. Each train includes a heater, a prefilter, moisture separators, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of radioiodines, and a fan. Ductwork, valves and/or dampers, and instrumentation also form part of the system. The moisture separators function to reduce the moisture content of the airstream. A second bank of HEPA filters follows the adsorber section to collect carbon fines and provide backup in case of failure of the main HEPA filter bank. Only the upstream HEPA filter and the charcoal adsorber section are credited in the analysis. The system initiates and maintains a negative air pressure in the shield building by means of filtered exhaust ventilation of the shield building following receipt of a safety injection (SI) signal. The system is described in Reference 2.

(continued)

BASES

BACKGROUND (continued)

The prefilters remove large particles in the air, and the moisture separators remove entrained water droplets present, to prevent excessive loading of the HEPA filters and charcoal absorbers. Heaters are included to reduce the relative humidity of the airstream on systems that operate in high humidity. Continuous operation of each train, for at least 10 hours per month, with heaters on, reduces moisture buildup on their HEPA filters and adsorbers. Cross-over flow ducts are provided between the two trains to allow the active train to draw air through the inactive train and cool the air to keep the charcoal beds on the inactive train from becoming too hot due to absorption of fission products.

The containment annulus vacuum fans maintain the annulus at -5 inches water gauge vacuum during normal operations. During accident conditions, the containment annulus vacuum fans are isolated from the air cleanup portion of the system.

The EGTS reduces the radioactive content in the shield building atmosphere following a DBA. Loss of the EGTS could cause site boundary doses, in the event of a DBA, to exceed the values given in the licensing basis.

APPLICABLE SAFETY ANALYSES

The EGTS design basis is established by the consequences of the limiting DBA, which is a LOCA. The accident analysis (Ref. 3) considers two different single failure scenarios. The first one assumes that only one train of the EGTS is functional due to a postulated single failure that disables the other train. An alternate scenario assumes a single failure of the pressure control loop associated with one train of pressure control operators (PCO). The first scenario is bounding for thyroid dose while the alternate scenario is bounding for beta and gamma doses. The accident analysis accounts for the reduction in airborne radioactive material provided by the number of filter trains in operation for each failure scenario. The amount of fission products available for release from containment is determined for a LOCA.

The safety analysis conservatively assumes the annulus is at -0.5 inches water gauge pressure prior to the LOCA. The analysis further assumes that upon receipt of a Containment Isolation Phase A (CIA) signal from the RPS, the EGTS fans automatically start and achieve a minimum flow of 3600 cfm (per train) within 18 seconds (20 seconds from the initiating event.) This does not include 10 seconds for diesel generator startup.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The analysis shows that the annulus pressure will rise to a positive value and then decrease to the EGTS control point for a single failure of one EGTS train, or slightly more negative for a single failure of a pressure control loop associated with one train of PCOs. The normal alignment for both EGTS control loops is the A-Auto position. With both EGTS control loops in A-Auto, both trains will function upon initiation of a CIA signal. In the event of a LOCA, the annulus vacuum control system isolates and both trains of the EGTS pressure control loops will be placed in service to maintain the required negative pressure. If annulus vacuum is lost during normal operations, the A-Auto position is unaffected by the loss of vacuum. This operational configuration is acceptable because the accident dose analysis conservatively assumes the annulus is at atmospheric pressure at event initiation.

The EGTS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

In the event of a DBA, one EGTS train is required to provide the minimum particulate iodine removal assumed in the safety analysis. Two trains of the EGTS must be OPERABLE to ensure that at least one train will operate, assuming that the other train is disabled by a single active failure.

See TS Bases 3.6.15, “Shield Building,” for additional information on EGTS.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could lead to fission product release to containment that leaks to the shield building. The large break LOCA, on which this system's design is based, is a full power event. Less severe LOCAs and leakage still require the system to be OPERABLE throughout these MODES. The probability and severity of a LOCA decrease as core power and Reactor Coolant System pressure decrease. With the reactor shut down, the probability of release of radioactivity resulting from such an accident is low.

In MODES 5 and 6, the probability and consequences of a DBA are low due to the pressure and temperature limitations in these MODES. Under these conditions, the Filtration System is not required to be OPERABLE (although one or more trains may be operating for other reasons, such as habitability during maintenance in the shield building annulus).

BASES

ACTIONS (continued)

A.1

With one EGTS train inoperable, the inoperable train must be restored to OPERABLE status within 7 days. The components in this degraded condition are capable of providing 100% of the iodine removal needs after a DBA. The 7-day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant EGTS train and the low probability of a DBA occurring during this period. The Completion Time is adequate to make most repairs.

B.1 and B.2

If the EGTS train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.9.1

Operating each EGTS train for ≥ 10 hours ensures that all trains are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. Operation with the heaters on (automatic heater cycling to maintain temperature) for ≥ 10 continuous hours eliminates moisture on the adsorbers and HEPA filters. Experience from filter testing at operating units indicates that the 10-hour period is adequate for moisture elimination on the adsorbers and HEPA filters. The 31-day Frequency was developed in consideration of the known reliability of fan motors and controls, the two train redundancy available.

SR 3.6.9.2

This SR verifies that the required EGTS filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP - Technical Specification Section 5.7.2.14). The EGTS filter tests are in accordance with Regulatory Guide 1.52 (Ref. 4). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations).

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.9.2 (continued)

Specific test frequencies and additional information are discussed in detail in the VFTP. It should be noted that for the EGTS, the VFTP pressure drop value across the entire filtration unit does not account for instrument error.

SR 3.6.9.3

The automatic startup ensures that each EGTS train responds properly. This testing includes the automatic swapping logic of the EGTS pressure control isolation valves in response to the actuation signal. Performance of this swapping logic test will ensure the availability of EGTS functions in the event of an initial single failure of one of the pressure control loops. 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. Therefore the Frequency was concluded to be acceptable from a reliability standpoint. Furthermore, the SR interval was developed considering that the EGTS equipment OPERABILITY is demonstrated at a 31-day Frequency by SR 3.6.9.1.

SR 3.6.9.4

The proper functioning of the fans, dampers, filters, adsorbers, etc., as a system is verified by the ability of each train to produce the required system flow rate within the specified timeframe. The 18-month Frequency on a STAGGERED TEST BASIS is consistent with Regulatory Guide 1.52 (Ref. 4) guidance for functional testing.

BASES

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 41, “Containment Atmosphere Cleanup.”

2. Watts Bar FSAR, Section 6.5, “Fission Product Removal and Control Systems.”

3. Watts Bar FSAR, Section 15.0, “Accident Analysis.”

4. Regulatory Guide 1.52, Rev. 2, “Design, Testing and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmospheric Cleanup System Air Filtration and Absorption Units of Light-Water Cooled Nuclear Power Plants.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.10 Air Return System (ARS)

BASES

BACKGROUND

The ARS is designed to assure the rapid return of air from the upper to the lower containment compartment after the initial blowdown following a Design Basis Accident (DBA). The return of this air to the lower compartment and subsequent recirculation back up through the ice condenser assists in cooling the containment atmosphere and limiting post accident pressure and temperature in containment to less than design values. Limiting pressure and temperature reduces the release of fission product radioactivity from containment to the environment in the event of a DBA.

The ARS provides post accident hydrogen mixing in selected areas of containment. The ARS draws air from the dome of the containment vessel, from the reactor cavity, and from the ten dead ended (pocketed) spaces in the containment where there is potential for the accumulation of hydrogen. The minimum design flow from each potential hydrogen pocket is sufficient to limit the local concentration of hydrogen.

The ARS consists of two separate trains of equal capacity, each capable of meeting the design bases. Each train includes a 100% capacity air return fan, associated damper, and hydrogen collection headers. Each train is powered from a separate Engineered Safety Features (ESF) bus.

The ARS fans are automatically started by the containment isolation Phase B signal 8 to 10 minutes after the containment pressure reaches the pressure setpoint. The time delay ensures that no energy released during the initial phase of a DBA will bypass the ice bed through the ARS fans into the upper containment compartment.

After starting, the fans displace air from the upper compartment to the lower compartment, thereby returning the air that was displaced by the high energy line break blowdown from the lower compartment and equalizing pressures throughout containment. After discharge into the lower compartment, air flows with steam produced by residual heat through the ice condenser doors into the ice condenser compartment where the steam portion of the flow is condensed. The air flow returns to the upper compartment through the top deck doors in the upper portion of the ice condenser compartment. The ARS fans operate continuously after actuation, circulating air through the containment volume and

(continued)

BASES

BACKGROUND (continued)

purging all potential hydrogen pockets in containment. When the containment pressure falls below a predetermined value, the ARS fans are manually de-energized. Thereafter, the fans are manually cycled on and off if necessary to control any additional containment pressure transients.

The ARS also functions, after all the ice has melted, to circulate any steam still entering the lower compartment to the upper compartment where the Containment Spray System can cool it.

The ARS is an ESF system. It is designed to ensure that the heat removal capability required during the post accident period can be attained. The operation of the ARS, in conjunction with the ice bed, the Containment Spray System, and the Residual Heat Removal (RHR) System spray, provides the required heat removal capability to limit post accident conditions to less than the containment design values.

APPLICABLE SAFETY ANALYSES

The limiting DBAs considered relative to containment temperature and pressure are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. DBAs are assumed not to occur simultaneously or consecutively. The postulated DBAs are analyzed, in regard to ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in one train each of the Containment Spray System, RHR System, and ARS being inoperable (Ref. 1). The DBA analyses show that the maximum peak containment pressure results from the LOCA analysis and is calculated to be less than the containment design pressure.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures, in accordance with 10 CFR 50, Appendix K (Ref. 2).

(continued)

BASES (CO)

APPLICABLE SAFETY ANALYSES (continued)

The modeled ARS actuation from the containment analysis is based upon a response time associated with exceeding the containment pressure High-High signal setpoint to achieving full ARS air flow. A delayed response time initiation provides conservative analyses of peak calculated containment temperature and pressure responses. The ARS total response time of 540 ± 60 seconds consists of the built in signal delay.

The ARS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

In the event of a DBA, one train of the ARS is required to provide the minimum air recirculation for heat removal and hydrogen mixing assumed in the safety analyses. To ensure this requirement is met, two trains of the ARS must be OPERABLE. This will ensure that at least one train will operate, assuming the worst case single failure occurs, which is in the ESF power supply.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause an increase in containment pressure and temperature requiring the operation of the ARS. Therefore, the LCO is applicable in MODES 1, 2, 3, and 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the ARS is not required to be OPERABLE in these MODES.

ACTIONS

A.1

If one of the required trains of the ARS is inoperable, it must be restored to OPERABLE status within 72 hours. The components in this degraded condition are capable of providing 100% of the flow capability after an accident. The 72-hour Completion Time was developed taking into account the redundant flow and hydrogen mixing capability of the OPERABLE ARS train and the low probability of a DBA occurring in this period.

(continued)

BASES (CO)

ACTIONS (continued)

B.1 and B.2

If the ARS train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.10.1

Verifying that each ARS fan starts on an actual or simulated actuation signal, after a delay of ≥ 8.0 minutes and ≤ 10.0 minutes, and operates for ≥ 15 minutes is sufficient to ensure that all fans are OPERABLE and that all associated controls and time delays are functioning properly. It also ensures that blockage, fan and/or motor failure, or excessive vibration can be detected for corrective action. The 92 day Frequency was developed considering the known reliability of fan motors and controls and the two train redundancy available.

SR 3.6.10.2

Verifying ARS fan motor current with the return air backdraft dampers closed confirms one operating condition of the fan. This test is indicative of overall fan motor performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of 92 days conforms to the testing requirements for similar ESF equipment and considers the known reliability of fan motors and controls and the two train redundancy available.

SR 3.6.10.3

Verifying the OPERABILITY of the air return damper to the proper opening torque (Ref. 3) provides assurance that the proper flow path will exist when the fan is started. By applying the correct torque to the damper shaft, the damper operation can be confirmed. The Frequency of 92 days was developed considering the importance of the dampers, their location, physical environment, and probability of failure. Operating experience has also shown this Frequency to be acceptable.

BASES (continued)

REFERENCES

1. Watts Bar FSAR, Section 6.8, “Air Return Fans.”

2. Title 10, Code of Federal Regulations, Part 50, Appendix K, “ECCS Evaluation Models.”

3. System Description N3-30RB-4002.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.11 Ice Bed

BASES

BACKGROUND

The ice bed consists of over 2,750,700 lbs of ice stored in 1944 baskets within the ice condenser. Its primary purpose is to provide a large heat sink in the event of a release of energy from a Design Basis Accident (DBA) in containment. The ice would absorb energy and limit containment peak pressure and temperature during the accident transient. Limiting the pressure and temperature reduces the release of fission product radioactivity from containment to the environment in the event of a DBA.

The ice condenser is an annular compartment enclosing approximately 300° of the perimeter of the upper containment compartment, but penetrating the operating deck so that a portion extends into the lower containment compartment. The lower portion has a series of hinged doors exposed to the atmosphere of the lower containment compartment, which, for normal plant operation, are designed to remain closed. At the top of the ice condenser is another set of doors exposed to the atmosphere of the upper compartment, which also remain closed during normal plant operation. Intermediate deck doors, located below the top deck doors, form the floor of a plenum at the upper part of the ice condenser. These doors also remain closed during normal plant operation. The upper plenum area is used to facilitate surveillance and maintenance of the ice bed.

The ice baskets contain the ice within the ice condenser. The ice bed is considered to consist of the total volume from the bottom elevation of the ice baskets to the top elevation of the ice baskets. The ice baskets position the ice within the ice bed in an arrangement to promote heat transfer from steam to ice. This arrangement enhances the ice condenser's primary function of condensing steam and absorbing heat energy released to the containment during a DBA.

(continued)

BASES

BACKGROUND (continued)

In the event of a DBA, the ice condenser inlet doors (located below the operating deck) open due to the pressure rise in the lower compartment. This allows air and steam to flow from the lower compartment into the ice condenser. The resulting pressure increase within the ice condenser causes the intermediate deck doors and the top deck doors to open, which allows the air to flow out of the ice condenser into the upper compartment. Steam condensation within the ice condenser limits the pressure and temperature buildup in containment. A divider barrier separates the upper and lower compartments and ensures that the steam is directed into the ice condenser.

The ice, together with the containment spray, is adequate to absorb the initial blowdown of steam and water from a DBA and the additional heat loads that would enter containment during several hours following the initial blowdown. The additional heat loads would come from the residual heat in the reactor core, the hot piping and components, and the secondary system, including the steam generators. During the post blowdown period, the Air Return System (ARS) returns upper compartment air through the divider barrier to the lower compartment. This serves to equalize pressures in containment and to continue circulating heated air and steam from the lower compartment through the ice condenser where the heat is removed by the remaining ice.

As ice melts, the water passes through the ice condenser floor drains into the lower compartment. Thus, a second function of the ice bed is to be a large source of borated water (via the containment sump) for long term Emergency Core Cooling System (ECCS) and Containment Spray System heat removal functions in the recirculation mode.

A third function of the ice bed and melted ice is to remove fission product iodine that may be released from the core during a DBA. Iodine removal occurs during the ice melt phase of the accident and continues as the melted ice is sprayed into the containment atmosphere by the Containment Spray System. The ice is adjusted to an alkaline pH that facilitates removal of radioactive iodine from the containment atmosphere. The alkaline pH also minimizes the occurrence of the chloride and caustic stress corrosion on mechanical systems and components exposed to ECCS and Containment Spray System fluids in the recirculation mode of operation.

It is important for the ice to be uniformly distributed around the 24 ice condenser bays and for open flow paths to exist around ice baskets. This is especially important during the initial blowdown so that the steam and

(continued)

BASES

BACKGROUND (continued)

water mixture entering the lower compartment do not pass through only part of the ice condenser, depleting the ice there while bypassing the ice in other bays.

Two phenomena that can degrade the ice bed during the long service period are:

a. Loss of ice by melting or sublimation; and

b. Obstruction of flow passages through the ice bed due to buildup of frost or ice.

Both of these degrading phenomena are reduced by minimizing air leakage into and out of the ice condenser.

The ice bed limits the temperature and pressure that could be expected following a DBA, thus limiting leakage of fission product radioactivity from containment to the environment.

APPLICABLE SAFETY ANALYSES

The limiting DBAs considered relative to containment temperature and pressure are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. DBAs are not assumed to occur simultaneously or consecutively.

Although the ice condenser is a passive system that requires no electrical power to perform its function, the Containment Spray System and the ARS also function to assist the ice bed in limiting pressures and temperatures. Therefore, the postulated DBAs are analyzed in regards to containment Engineered Safety Feature (ESF) systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in one train each of the Containment Spray System and ARS being inoperable.

The limiting DBA analyses (Ref. 1) show that the maximum peak containment pressure results from the LOCA analysis and is calculated to be less than the containment design pressure. For certain aspects of the transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the ECCS during the core reflood phase of a LOCA analysis increases with increasing containment backpressure.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures, in accordance with 10 CFR 50, Appendix K (Ref. 2). The maximum peak containment atmosphere temperature results from the SLB analysis and is discussed in the Bases for LCO 3.6.5, “Containment Air Temperature.”

In addition to calculating the overall peak containment pressures, the DBA analyses include calculation of the transient differential pressures that occur across subcompartment walls during the initial blowdown phase of the accident transient. The internal containment walls and structures are designed to withstand these local transient pressure differentials for the limiting DBAs.

The ice bed satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The ice bed LCO requires the existence of the required quantity of stored ice, appropriate distribution of the ice and the ice bed, open flow paths through the ice bed, and appropriate chemical content and pH of the stored ice. The stored ice functions to absorb heat during a DBA, thereby limiting containment air temperature and pressure. The chemical content and pH of the ice provide core SDM (boron content) and remove radioactive iodine from the containment atmosphere when the melted ice is recirculated through the ECCS and the Containment Spray System, respectively.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause an increase in containment pressure and temperature requiring the operation of the ice bed. Therefore, the LCO is applicable in MODES 1, 2, 3, and 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the ice bed is not required to be OPERABLE in these MODES.

BASES (continued)

ACTIONS

A.1

If the ice bed is inoperable, it must be restored to OPERABLE status within 48 hours. The Completion Time was developed based on operating experience, which confirms that due to the very large mass of stored ice, the parameters comprising OPERABILITY do not change appreciably in this time period. Because of this fact, the Surveillance Frequencies are long (months), except for the ice bed temperature, which is checked every 12 hours. If a degraded condition is identified, even for temperature, with such a large mass of ice it is not possible for the degraded condition to significantly degrade further in a 48-hour period. Therefore, 48 hours is a reasonable amount of time to correct a degraded condition before initiating a shutdown.

B.1 and B.2

If the ice bed cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.11.1

Verifying that the maximum temperature of the ice bed is ≤ 27 °F (value does not account for instrument error) ensures that the ice is kept well below the melting point. The 12-hour Frequency was based on operating experience, which confirmed that, due to the large mass of stored ice, it is not possible for the ice bed temperature to degrade significantly within a 12-hour period and was also based on assessing the proximity of the LCO limit to the melting temperature.

Furthermore, the 12-hour Frequency is considered adequate in view of indications in the control room, including the alarm, to alert the operator to an abnormal ice bed temperature condition. This SR may be satisfied by use of the Ice Bed Temperature Monitoring System.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.11.2

The weighing program is designed to obtain a representative sample of the ice baskets. The representative sample shall include 6 baskets from each of the 24 ice condenser bays and shall consist of one basket from radial rows 1, 2, 4, 6, 8, and 9. If no basket from a designated row can be obtained for weighing, a basket from the same row of an adjacent bay shall be weighed.

The rows chosen include the rows nearest the inside and outside walls of the ice condenser (rows 1 and 2, and 8 and 9, respectively), where heat transfer into the ice condenser is most likely to influence melting or sublimation. Verifying the total weight of ice ensures that there is adequate ice to absorb the required amount of energy to mitigate the DBAs.

If a basket is found to contain less than 1415 lb of ice, a representative sample of 20 additional baskets from the same bay shall be weighed. The average weight of ice in these 21 baskets (the discrepant basket and the 20 additional baskets) shall be greater than or equal to 1415 lb at a 95% confidence level. [Value does not account for instrument error.]

Weighing 20 additional baskets from the same bay in the event a Surveillance reveals that a single basket contains less than 1415 lb ensures that no local zone exists that is grossly deficient in ice. Such a zone could experience early melt out during a DBA transient, creating a path for steam to pass through the ice bed without being condensed. The Frequency of 18 months was based on ice storage tests and the allowance built into the required ice mass over and above the mass assumed in the safety analyses. Operating experience has verified that, with the 18 month Frequency, the weight requirements are maintained with no significant degradation between surveillances.

SR 3.6.11.3

This SR ensures that the azimuthal distribution of ice is reasonably uniform, by verifying that the average ice weight in each of three azimuthal groups of ice condenser bays is within the limit. The Frequency of 18 months was based on ice storage tests and the allowance built into the required ice mass over and above the mass assumed in the safety analyses. Operating experience has verified that, with the 18-month Frequency, the weight requirements are maintained with no significant degradation between surveillances.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.11.4

This SR ensures that the air/steam flow channels through the ice bed have not accumulated ice blockage that exceeds 15 percent of the total flow area through the ice bed region. The allowable 15 percent buildup of ice is based on the analysis of the subcompartment response to a design basis LOCA with partial blockage of the ice bed flow channels. The analysis did not perform detailed flow area modeling, but rather lumped the ice condenser bays into six sections ranging from 2.75 bays to 6.5 bays. Individual bays are acceptable with greater than 15 percent blockage, as long as 15 percent blockage is not exceeded for any analysis section.

To provide a 95 percent confidence that flow blockage does not exceed the allowed 15 percent, the visual inspection must be made for at least 54 (33 percent) of the 162 flow channels per ice condenser bay. The visual inspection of the ice bed flow channels is to inspect the flow area, by looking down from the top of the ice bed, and where view is achievable up from the bottom of the ice bed. Flow channels to be inspected are determined by random sample. As the most restrictive flow passage location is found at a lattice frame elevation, the 15 percent blockage criteria only applies to “flow channels” that comprise the area:

a. between ice baskets, and

b. past lattice frames and wall panels.

Due to a significantly larger flow area in the regions of the upper deck grating and the lower inlet plenum and turning vanes, it would require a gross buildup of ice on these structures to obtain degradation in air/steam flow. Therefore, these structures are excluded as part of a flow channel for application of the 15 percent blockage criteria. Plant and industry experience have shown that removal of ice from the excluded structures during the refueling outage is sufficient to ensure they remain operable throughout the operating cycle. Thus, removal of any gross ice buildup on the excluded structures is performed following outage maintenance activities.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.11.4 (continued)

Operating experience has demonstrated that the ice bed is the region that is the most flow restrictive, due to the normal presence of ice accumulation on lattice frames and wall panels. The flow area through the ice basket support platform is not a more restrictive flow area because it is easily accessible from the lower plenum and is maintained clear of ice accumulation. There is not a mechanistically credible method for ice to accumulate on the ice basket support platform during plant operation. Plant and industry experience has shown that the vertical flow area through the ice basket support platform remains clear of ice accumulation that could produce blockage. Normally, only a glaze may develop or exist on the ice basket support platform which is not significant to blockage of flow area. Additionally, outage maintenance practices provide measures to clear the ice basket support platform following maintenance activities of any accumulation of ice that could block flow areas.

Frost buildup or loose ice is not to be considered as flow channel blockage, whereas attached ice is considered blockage of a flow channel. Frost is the solid form of water that is loosely adherent, and can be brushed off with the open hand.

The Frequency of 18 months was based on ice storage tests and the allowance built into the required ice mass over and above the mass assumed in the safety analyses.

SR 3.6.11.5

Verifying the chemical composition of the stored ice ensures that the stored ice has a boron concentration of ≥ 1800 ppm and ≤ 2000 ppm as sodium tetraborate and a high pH, ≥ 9.0 and ≤ 9.5, in order to meet the requirement for borated water when the melted ice is used in the ECCS recirculation mode of operation. Additionally, the minimum boron concentration setpoint is used to assure reactor subcriticality in a post LOCA environment, while the maximum boron concentration is used as the bounding value in the hot leg switchover timing calculation (Ref. 3). This is accomplished by obtaining at least 24 ice samples. Each sample is taken approximately one foot from the top of the ice of each randomly selected ice basket in each ice condenser bay. The SR is modified by a NOTE that allows the boron concentration and pH value obtained from averaging the individual samples' analysis results to satisfy the requirements of the SR. If either the average boron concentration or the average pH value is outside their prescribed limit, then entry into ACTION Condition A is required. Sodium tetraborate has been proven effective in

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.11.5 (continued)

maintaining the boron content for long storage periods, and it also enhances the ability of the solution to remove and retain fission product iodine. The high pH is required to enhance the effectiveness of the ice and the melted ice in removing iodine from the containment atmosphere. This pH range also minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to ECCS and Containment Spray System fluids in the recirculation mode of operation. The Frequency of 54 months is intended to be consistent with the expected length of three fuel cycles, and was developed considering these facts:

a. Long term ice storage tests have determined that the chemical composition of the stored ice is extremely stable;

b. There are no normal operating mechanisms that decrease the boron concentration of the stored ice, and pH remains within a 9.0 through 9.5 range when boron concentrations are above approximately 1200 ppm.

c. Operating experience has demonstrated that meeting the boron concentration and pH requirements has never been a problem; and

d. Someone would have to enter the containment to take the sample, and, if the unit is at power, that person would receive a radiation dose.

SR 3.6.11.6

This SR ensures that a representative sampling of ice baskets, which are relatively thin walled, perforated cylinders, have not been degraded by wear, cracks, corrosion, or other damage. Each ice basket must be raised at least 10 feet for this inspection. However, for baskets where vertical lifting height is restricted due to overhead obstruction, a camera shall be used to perform the inspection. The Frequency of 40 months for a visual inspection of the structural soundness of the ice baskets is based on engineering judgment and considers such factors as the thickness of the basket walls relative to corrosion rates expected in their service environment and the results of the long term ice storage testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.11.7

This SR ensures that initial ice fill and any subsequent ice additions meet the boron concentration and pH requirements of SR 3.6.11.5. The SR is modified by a NOTE that allows the chemical analysis to be performed on either the liquid or resulting ice of each sodium tetraborate solution prepared. If ice is obtained from offsite sources, then chemical analysis data must be obtained for the ice supplied.

REFERENCES

1. Watts Bar FSAR, Section 6.2, “Containment Systems” and Section 6.7, “Ice Condenser System.”

2. Title 10, Code of Federal Regulations, Part 50, Appendix K, “ECCS Evaluation Models.”

3. Westinghouse Letter, WAT-D-10686, “Upper Limit Ice Boron Concentration In Safety Analysis.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.12 Ice Condenser Doors

BASES

BACKGROUND

The ice condenser doors consist of the inlet doors, the intermediate deck doors, and the top deck doors. The functions of the doors are to:

a. Seal the ice condenser from air leakage during the lifetime of the plant; and

b. Open in the event of a Design Basis Accident (DBA) to direct the hot steam air mixture from the DBA into the ice bed, where the ice would absorb energy and limit containment peak pressure and temperature during the accident transient.

Limiting the pressure and temperature following a DBA reduces the release of fission product radioactivity from containment to the environment.

The ice condenser is an annular compartment enclosing approximately 300° of the perimeter of the upper containment compartment, but penetrating the operating deck so that a portion extends into the lower containment compartment. The inlet doors separate the atmosphere of the lower compartment from the ice bed inside the ice condenser. The top deck doors are above the ice bed and exposed to the atmosphere of the upper compartment. The intermediate deck doors, located below the top deck doors, form the floor of a plenum at the upper part of the ice condenser. This plenum area is used to facilitate surveillance and maintenance of the ice bed.

The ice baskets held in the ice bed within the ice condenser are arranged to promote heat transfer from steam to ice. This arrangement enhances the ice condenser's primary function of condensing steam and absorbing heat energy released to the containment during a DBA.

(continued)

BASES

BACKGROUND (continued)

In the event of a DBA, the ice condenser inlet doors (located below the operating deck) open due to the pressure rise in the lower compartment. This allows air and steam to flow from the lower compartment into the ice condenser. The resulting pressure increase within the ice condenser causes the intermediate deck doors and the top deck doors to open, which allows the air to flow out of the ice condenser into the upper compartment. Steam condensation within the ice condensers limits the pressure and temperature buildup in containment. A divider barrier separates the upper and lower compartments and ensures that the steam is directed into the ice condenser.

The ice, together with the containment spray, serves as a containment heat removal system and is adequate to absorb the initial blowdown of steam and water from a DBA as well as the additional heat loads that would enter containment during the several hours following the initial blowdown. The additional heat loads would come from the residual heat in the reactor core, the hot piping and components, and the secondary system, including the steam generators. During the post blowdown period, the Air Return System (ARS) returns upper compartment air through the divider barrier to the lower compartment. This serves to equalize pressures in containment and to continue circulating heated air and steam from the lower compartment through the ice condenser, where the heat is removed by the remaining ice.

The water from the melted ice drains into the lower compartment where it serves as a source of borated water (via the containment sump) for the Emergency Core Cooling System (ECCS) and the Containment Spray System heat removal functions in the recirculation mode. The ice (via the Containment Spray System) and the recirculated ice melt also serve to clean up the containment atmosphere.

The ice condenser doors ensure that the ice stored in the ice bed is preserved during normal operation (doors closed) and that the ice condenser functions as designed if called upon to act as a passive heat sink following a DBA.

APPLICABLE SAFETY ANALYSES

The limiting DBAs considered relative to containment pressure and temperature are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. DBAs are assumed not to occur simultaneously or consecutively.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Although the ice condenser is a passive system that requires no electrical power to perform its function, the Containment Spray System and ARS also function to assist the ice bed in limiting pressures and temperatures. Therefore, the postulated DBAs are analyzed with respect to Engineered Safety Feature (ESF) systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in one train each of the Containment Spray System and the ARS being rendered inoperable.

The limiting DBA analyses (Ref. 1) show that the maximum peak containment pressure results from the LOCA analysis and is calculated to be less than the containment design pressure. For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the ECCS during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures, in accordance with 10 CFR 50, Appendix K (Ref. 2).

The maximum peak containment atmosphere temperature results from the SLB analysis and is discussed in the Bases for LCO 3.6.5, “Containment Air Temperature.”

An additional design requirement was imposed on the ice condenser door design for a small break accident in which the flow of heated air and steam is not sufficient to fully open the doors.

For this situation, the doors are designed so that all of the doors would partially open by approximately the same amount. Thus, the partially opened doors would modulate the flow so that each ice bay would receive an approximately equal fraction of the total flow.

This design feature ensures that the heated air and steam will not flow preferentially to some ice bays and deplete the ice there without utilizing the ice in the other bays.

In addition to calculating the overall peak containment pressures, the DBA analyses include the calculation of the transient differential pressures that would occur across subcompartment walls during the initial blowdown phase of the accident transient. The internal containment walls and structures are designed to withstand the local transient pressure differentials for the limiting DBAs.

The ice condenser doors satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

This LCO establishes the minimum equipment requirements to assure that the ice condenser doors perform their safety function. The ice condenser inlet doors, intermediate deck doors, and top deck doors must be closed to minimize air leakage into and out of the ice condenser, with its attendant leakage of heat into the ice condenser and loss of ice through melting and sublimation. The doors must be OPERABLE to ensure the proper opening of the ice condenser in the event of a DBA. OPERABILITY includes being free of any obstructions that would limit their opening, and for the inlet doors, being adjusted such that the opening and closing torques are within limits. The ice condenser doors function with the ice condenser to limit the pressure and temperature that could be expected following a DBA.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause an increase in containment pressure and temperature requiring the operation of the ice condenser doors. Therefore, the LCO is applicable in MODES 1, 2, 3, and 4.

The probability and consequences of these events in MODES 5 and 6 are reduced due to the pressure and temperature limitations of these MODES. Therefore, the ice condenser doors are not required to be OPERABLE in these MODES.

ACTIONS

A Note provides clarification that, for this LCO, separate Condition entry is allowed for each ice condenser door.

A.1

If one or more ice condenser inlet doors are inoperable due to being physically restrained from opening, the door(s) must be restored to OPERABLE status within 1 hour. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, “Containment,” which requires containment to be restored to OPERABLE status within 1 hour.

(continued)

BASES (continued)

ACTIONS (continued)

B.1 and B.2

If one or more ice condenser doors are determined to be partially open or otherwise inoperable for reasons other than Condition A or if a door is found that is not closed, it is acceptable to continue plant operation for up to 14 days, provided the ice bed temperature instrumentation is monitored once per 4 hours to ensure that the open or inoperable door is not allowing enough air leakage to cause the maximum ice bed temperature to approach the melting point. The Frequency of 4 hours is based on the fact that temperature changes cannot occur rapidly in the ice bed because of the large mass of ice involved. The 14-day Completion Time is based on long term ice storage tests that indicate that if the temperature is maintained below 27°F, there would not be a significant loss of ice from sublimation. If the maximum ice bed temperature is > 27°F at any time, or ice bed temperature is not verified to be within the specified Frequency as augmented by the provisions of SR 3.0.2, the situation reverts to Condition C and a Completion Time of 48 hours is allowed to restore the inoperable door to OPERABLE status or enter into Required Actions D.1 and D.2. NOTE: Entry into Condition B is not required due to personnel standing on or opening an intermediate deck or top deck door for short durations to perform required surveillances, minor maintenance such as ice removal, or routine tasks such as system walkdowns.

C.1

If Required Actions or Completion Times of B.1 or B.2 is not met, the doors must be restored to OPERABLE status and closed positions within 48 hours. The 48-hour Completion Time is based on the fact that, with the very large mass of ice involved, it would not be possible for the temperature to increase to the melting point and a significant amount of ice to melt in a 48-hour period.

D.1 and D.2

If the ice condenser doors cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 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.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.12.1

Verifying, by means of the Inlet Door Position Monitoring System, that the inlet doors are in their closed positions makes the operator aware of an inadvertent opening of one or more doors. The Frequency of 12 hours ensures that operators on each shift are aware of the status of the doors.

SR 3.6.12.2

Verifying, by visual inspection, that each intermediate deck door is closed and not impaired by ice, frost, or debris provides assurance that the intermediate deck doors (which form the floor of the upper plenum where frequent maintenance on the ice bed is performed) have not been left open or obstructed. The Frequency of 7 days is based on engineering judgment and takes into consideration such factors as the frequency of entry into the intermediate ice condenser deck, the time required for significant frost buildup, and the probability that a DBA will occur.

SR 3.6.12.3

Verifying, by visual inspection, that the ice condenser inlet doors are not impaired by ice, frost, or debris provides assurance that the doors are free to open in the event of a DBA. For this unit, the Frequency of 18 months (3 months during the first year after receipt of license) is based on door design, which does not allow water condensation to freeze, and operating experience, which indicates that the inlet doors very rarely fail to meet their SR acceptance criteria. Because of high radiation in the vicinity of the inlet doors during power operation, this Surveillance is normally performed during a shutdown.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.12.4

Verifying the opening torque of the inlet doors provides assurance that no doors have become stuck in the closed position. The value of 675 in-lb is based on the design opening pressure on the doors of 1.0 lb/ft^2. For this unit, the Frequency of 18 months (3 months during the first year after receipt of license) is based on the passive nature of the closing mechanism (i.e., once adjusted, there are no known factors that would change the setting, except possibly a buildup of ice; ice buildup is not likely, however, because of the door design, which does not allow water condensation to freeze). Operating experience indicates that the inlet doors usually meet their SR acceptance criteria. Because of high radiation in the vicinity of the inlet doors during power operation, this Surveillance is normally performed during a shutdown.

SR 3.6.12.5

The torque test Surveillance ensures that the inlet doors have not developed excessive friction and that the return springs are producing a door return torque within limits. The torque test consists of the following:

1. Verify that the torque, T(OPEN), required to cause opening motion at the 40° open position is ≤ 195 in-lb;

2. Verify that the torque, T(CLOSE), required to hold the door stationary (i.e., keep it from closing) at the 40° open position is ≥ 78 in-lb; and

3. Calculate the frictional torque,

   T(FRICT) = 0.5 {T(OPEN) - T(CLOSE)},

   and verify that the T(FRICT) is ≤ 40 in-lb.

The purpose of the friction and return torque Specifications is to ensure that, in the event of a small break LOCA or SLB, all of the 24 door pairs open uniformly. This assures that, during the initial blowdown phase, the steam and water mixture entering the lower compartment does not pass through part of the ice condenser, depleting the ice there, while bypassing the ice in other bays. The Frequency of 18 months (3 months during the first year after receipt of license) is based on the passive nature of the closing mechanism (i.e., once adjusted, there are no known factors that would change the setting, except possibly a buildup of ice; ice buildup is not likely, however, because of the door design, which does not allow water condensation to freeze). Operating experience indicates that the inlet doors very rarely fail to meet their SR acceptance criteria. Because of high radiation in the vicinity of the inlet doors during power operation, this Surveillance is normally performed during a shutdown.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.12.6

Verifying the OPERABILITY of the intermediate deck doors provides assurance that the intermediate deck doors are free to open in the event of a DBA. The verification consists of visually inspecting the intermediate doors for structural deterioration, verifying free movement of the vent assemblies, and ascertaining free movement of each door when lifted with the applicable force shown below:

DOOR	LIFTING FORCE
a. Adjacent to crane wall	< 37.4 lb
b. Paired with door adjacent to crane wall	≤ 33.8 lb
c. Adjacent to containment wall	≤ 31.8 lb
d. Paired with door adjacent to containment wall	≤ 31.0 lb

The above test lifting forces were established based upon test results gathered on newly manufactured Intermediate Deck Doors set up in fixturing to simulate plant installation tolerances. The lifting force values developed were to account for and envelope expected door panel variations in weight and hinge friction and alignments. The intent of the surveillance is to establish a method of detecting abnormalities or deteriorating conditions of the door panels or hinges after completion of refueling outage maintenance activities.

The 18-month Frequency (3 months during the first year after receipt of license) is based on the passive design of the intermediate deck doors, the frequency of personnel entry into the intermediate deck, and the fact that SR 3.6.12.2 confirms on a 7 day Frequency that the doors are not impaired by ice, frost, or debris, which are ways a door would fail the opening force test (i.e., by sticking or from increased door weight).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.12.7

Verifying, by visual inspection, that the top deck doors are in place, not obstructed, and verifying free movement of the vent assembly provides assurance that the doors are performing their function of keeping warm air out of the ice condenser during normal operation, and would not be obstructed if called upon to open in response to a DBA. The Frequency of 92 days is based on engineering judgment, which considered such factors as the following:

a. The relative inaccessibility and lack of traffic in the vicinity of the doors make it unlikely that a door would be inadvertently left open;

b. Excessive air leakage would be detected by temperature monitoring in the ice condenser; and

c. The light construction of the doors would ensure that, in the event of a DBA, air and gases passing through the ice condenser would find a flow path, even if a door were obstructed.

REFERENCES

1. Watts Bar FSAR, Section 6.2.1, “Containment Functional Design” and Section 6.7, “Ice Condenser System.”

2. Title 10, Code of Federal Regulations, Part 50, Appendix K, “ECCS Evaluation Models.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.13 Divider Barrier Integrity

BASES

BACKGROUND

The divider barrier consists of the operating deck and associated seals, personnel access doors, and equipment hatches that separate the upper and lower containment compartments. Divider barrier integrity is necessary to minimize bypassing of the ice condenser by the hot steam and air mixture released into the lower compartment during a Design Basis Accident (DBA). This ensures that most of the gases pass through the ice bed, which condenses the steam and limits pressure and temperature during the accident transient. Limiting the pressure and temperature reduces the release of fission product radioactivity from containment to the environment in the event of a DBA.

In the event of a DBA, the ice condenser inlet doors (located below the operating deck) open due to the pressure rise in the lower compartment. This allows air and steam to flow from the lower compartment into the ice condenser. The resulting pressure increase within the ice condenser causes the intermediate deck doors and the door panels at the top of the condenser to open, which allows the air to flow out of the ice condenser into the upper compartment. The ice condenses the steam as it enters, thus limiting the pressure and temperature buildup in containment. The divider barrier separates the upper and lower compartments and ensures that the steam is directed into the ice condenser. The ice, together with the containment spray, is adequate to absorb the initial blowdown of steam and water from a DBA as well as the additional heat loads that would enter containment over several hours following the initial blowdown. The additional heat loads would come from the residual heat in the reactor core, the hot piping and components, and the secondary system, including the steam generators. During the post blowdown period, the Air Return System (ARS) returns upper compartment air through the divider barrier to the lower compartment. This serves to equalize pressures in containment and to continue circulating heated air and steam from the lower compartment through the ice condenser, where the heat is removed by the remaining ice.

Divider barrier integrity ensures that the high energy fluids released during a DBA would be directed through the ice condenser and that the ice condenser would function as designed if called upon to act as a passive heat sink following a DBA.

BASES (continued)

APPLICABLE SAFETY ANALYSES

Divider barrier integrity ensures the functioning of the ice condenser to the limiting containment pressure and temperature that could be experienced following a DBA. The limiting DBAs considered relative to containment temperature and pressure are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. DBAs are assumed not to occur simultaneously or consecutively.

Although the ice condenser is a passive system that requires no electrical power to perform its function, the Containment Spray System and the ARS also function to assist the ice bed in limiting pressures and temperatures. Therefore, the postulated DBAs are analyzed, with respect to containment Engineered Safety Feature (ESF) systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in the inoperability of one train in both the Containment Spray System and the ARS.

The limiting DBA analyses (Ref. 1) show that the maximum peak containment pressure results from the LOCA analysis and is calculated to be less than the containment design pressure. The maximum peak containment temperature results from the SLB analysis and is discussed in the Bases for LCO 3.6.5, “Containment Air Temperature.”

In addition to calculating the overall peak containment pressures, the DBA analyses include calculation of the transient differential pressures that occur across subcompartment walls during the initial blowdown phase of the accident transient. The internal containment walls and structures are designed to withstand these local transient pressure differentials for the limiting DBAs.

The divider barrier satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

This LCO establishes the minimum equipment requirements to ensure that the divider barrier performs its safety function of ensuring that bypass leakage, in the event of a DBA, does not exceed the bypass leakage assumed in the accident analysis. Included are the requirements that the personnel access doors and equipment hatches in the divider barrier are OPERABLE and closed and that the divider barrier seal is properly installed and has not degraded with time. An exception to the requirement that the doors be closed is made to allow personnel transit entry through the divider barrier. The basis of this exception is the assumption that, for personnel transit, the time during which a door is open will be short (i.e., shorter than the Completion Time of 1 hour for Condition A). The divider barrier functions with the ice condenser to limit the pressure and temperature that could be expected following a DBA.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause an increase in containment pressure and temperature requiring the integrity of the divider barrier. Therefore, the LCO is applicable in MODES 1, 2, 3, and 4.

The probability and consequences of these events in MODES 5 and 6 are low due to the pressure and temperature limitations of these MODES. As such, divider barrier integrity is not required in these MODES.

ACTIONS

A.1

If one or more personnel access doors or equipment hatches are inoperable or open, 1 hour is allowed to restore the door(s) and equipment hatches to OPERABLE status and the closed position. The 1 hour Completion Time is consistent with LCO 3.6.1, “Containment,” which requires that containment be restored to OPERABLE status within 1 hour.

Condition A has been modified by a Note to provide clarification that separate Condition entry is allowed for each personnel access door or equipment hatch.

B.1

If the divider barrier seal is inoperable, 1 hour is allowed to restore the seal to OPERABLE status. The 1 hour Completion Time is consistent with LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the divider barrier integrity cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.13.1

Verification, by visual inspection, that all personnel access doors and equipment hatches between the upper and lower containment compartments are closed provides assurance that divider barrier integrity is maintained prior to the reactor being taken from MODE 5 to MODE 4. The visual inspection shall include the canal gate and control rod drive missile shield which penetrate the divider barrier. This SR is necessary because many of the doors and hatches may have been opened for maintenance during the shutdown.

SR 3.6.13.2

Verification, by visual inspection, that the personnel access door and equipment hatch seals, sealing surfaces, and alignments are acceptable provides assurance that divider barrier integrity is maintained. This inspection cannot be made when the door or hatch is closed. Therefore, SR 3.6.13.2 is required for each door or hatch that has been opened, prior to the final closure. Some doors and hatches may not be opened for long periods of time. Those that use resilient materials in the seals must be opened and inspected at least once every 10 years to provide assurance that the seal material has not aged to the point of degraded performance. The Frequency of 10 years is based on the known resiliency of the materials used for seals, the fact that the openings have not been opened (to cause wear), and operating experience that confirms that the seals inspected at this Frequency have been found to be acceptable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.13.3

Verification, by visual inspection, after each opening of a personnel access door or equipment hatch that it has been closed makes the operator aware of the importance of closing it and thereby provides additional assurance that divider barrier integrity is maintained while in applicable MODES.

SR 3.6.13.4

Not used.

SR 3.6.13.5

Visual inspection of the seal around the perimeter provides assurance that the seal is properly secured in place. The Frequency of 18 months was developed considering such factors as the inaccessibility of the seals and absence of traffic in their vicinity, the strength of the bolts and mechanisms used to secure the seal, and the plant conditions needed to perform the SR. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. Watts Bar FSAR, Section 6.2, “Containment Systems.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.14 Containment Recirculation Drains

BASES

BACKGROUND

The containment recirculation drains consist of the ice condenser drains and the refueling canal drains. The ice condenser is partitioned into 24 bays, each having a pair of inlet doors that open from the bottom plenum to allow the hot steam-air mixture from a Design Basis Accident (DBA) to enter the ice condenser. Twenty of the 24 bays have an ice condenser floor drain at the bottom to drain the melted ice into the lower compartment (in the 4 bays that do not have drains, the water drains through the floor drains in the adjacent bays). Each drain leads to a drain pipe that drops down several feet, then makes one or more 90° bends and exits into the lower compartment. A check (flapper) gate at the end of each pipe keeps warm air from entering during normal operation, but when the water exerts pressure, it opens to allow the water to spill into the lower compartment. This prevents water from backing up and interfering with the ice condenser inlet doors. The water delivered to the lower containment serves to cool the atmosphere as it falls through to the floor and provides a source of borated water at the containment sump for long term use by the Emergency Core Cooling System (ECCS) and the Containment Spray System during the recirculation mode of operation.

The two refueling canal drains are at low points in the refueling canal. During a refueling, plugs are installed in the drains and the canal is flooded to facilitate the refueling process. The water acts to shield and cool the spent fuel as it is transferred from the reactor vessel to storage. After refueling, the canal is drained and the plugs removed. In the event of a DBA, the refueling canal drains are the main return path to the lower compartment for Containment Spray System water sprayed into the upper compartment.

The ice condenser drains and the refueling canal drains function with the ice bed, the Containment Spray System, and the ECCS to limit the pressure and temperature that could be expected following a DBA.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The limiting DBAs considered relative to containment pressure and temperature are the loss of coolant accident (LOCA) and the steam line break (SLB) respectively. The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. DBAs are assumed not to occur simultaneously or consecutively. Although the ice condenser is a passive system that requires no electrical power to perform its function, the Containment Spray System and the Air Return System (ARS) also function to assist the ice bed in limiting pressures and temperatures. Therefore, the analysis of the postulated DBAs, with respect to Engineered Safety Feature (ESF) systems, assumes the loss of one ESF bus, which is the worst case single active failure and results in one train of the Containment Spray System and one train of the ARS being rendered inoperable.

The limiting DBA analyses (Ref. 1) show that the maximum peak containment pressure results from the LOCA analysis and is calculated to be less than the containment design pressure. The maximum peak containment atmosphere temperature results from the SLB analysis and is discussed in the Bases for LCO 3.6.5, “Containment Air Temperature.” In addition to calculating the overall peak containment pressures, the DBA analyses include calculation of the transient differential pressures that occur across subcompartment walls during the initial blowdown phase of the accident transient. The internal containment walls and structures are designed to withstand these local transient pressure differentials for the limiting DBAs.

The containment recirculation drains satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO establishes the minimum requirements to ensure that the containment recirculation drains perform their safety functions. The ice condenser floor drain valve gates must be closed to minimize air leakage into and out of the ice condenser during normal operation and must open in the event of a DBA when water begins to drain out. The refueling canal drains must have their plugs removed and remain clear to ensure the return of Containment Spray System water to the lower containment in the event of a DBA. The containment recirculation drains function with the ice condenser, ECCS, and Containment Spray System to limit the pressure and temperature that could be expected following a DBA.

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause an increase in containment pressure and temperature, which would require the operation of the containment recirculation drains. Therefore, the LCO is applicable in MODES 1, 2, 3, and 4.

The probability and consequences of these events in MODES 5 and 6 are low due to the pressure and temperature limitations of these MODES. As such, the containment recirculation drains are not required to be OPERABLE in these MODES.

ACTIONS

A.1

If one ice condenser floor drain is inoperable, 1 hour is allowed to restore the drain to OPERABLE status. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, “Containment,” which requires that containment be restored to OPERABLE status within 1 hour.

B.1

If one refueling canal drain is inoperable, 1 hour is allowed to restore the drain to OPERABLE status. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status in 1 hour.

C.1 and C.2

If the affected drain(s) cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 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.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.14.1

Verifying the OPERABILITY of the refueling canal drains ensures that they will be able to perform their functions in the event of a DBA. This Surveillance confirms that the refueling canal drain plugs have been removed and that the drains are clear of any obstructions that could impair their functioning. In addition to debris near the drains, attention must be given to any debris that is located where it could be moved to the drains in the event that the Containment Spray System is in operation and water is flowing to the drains. SR 3.6.14.1 must be performed before entering MODE 4 from MODE 5 after every filling of the canal to ensure that the plugs have been removed and that no debris that could impair the drains was deposited during the time the canal was filled. The 92 day Frequency was developed considering such factors as the inaccessibility of the drains, the absence of traffic in the vicinity of the drains, and the redundancy of the drains.

SR 3.6.14.2

Verifying the OPERABILITY of the ice condenser floor drains ensures that they will be able to perform their functions in the event of a DBA. Inspecting the drain valve gate ensures that the gate is performing its function of sealing the drain line from warm air leakage into the ice condenser during normal operation, yet will open if melted ice fills the line following a DBA. Verifying that the drain lines are not obstructed ensures their readiness to drain water from the ice condenser. The 18 month Frequency was developed considering such factors as the inaccessibility of the drains during power operation; the design of the ice condenser, which precludes melting and refreezing of the ice; and operating experience that has confirmed that the drains are found to be acceptable when the Surveillance is performed at an 18 month Frequency. Because of high radiation in the vicinity of the drains during power operation, this Surveillance is normally done during a shutdown.

REFERENCES

1. Watts Bar FSAR, Section 6.2, “Containment Systems.”

B 3.6 CONTAINMENT SYSTEMS

B 3.6.15 Shield Building

BASES

BACKGROUND

The shield building is a concrete structure that surrounds the steel containment vessel. Between the containment vessel and the shield building inner wall is an annular space that collects containment leakage that may occur following a loss of coolant accident (LOCA) as well as other design basis accidents (DBAs) that release radioactive material. This space also allows for periodic inspection of the outer surface of the steel containment vessel.

The Emergency Gas Treatment System (EGTS) establishes a negative pressure in the annulus between the shield building and the steel containment vessel. Filters in the system then control the release of radioactive contaminants to the environment. The shield building is required to be OPERABLE to ensure retention of containment leakage and proper operation of the EGTS.

APPLICABLE SAFETY ANALYSES

The design basis for shield building OPERABILITY is a LOCA. Maintaining shield building OPERABILITY ensures that the release of radioactive material from the containment atmosphere is restricted to those leakage paths and associated leakage rates assumed in the accident analyses.

The shield building satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Shield building OPERABILITY must be maintained to ensure proper operation of the EGTS and to limit radioactive leakage from the containment to those paths and leakage rates assumed in the accident analyses.

BASES (continued)

APPLICABILITY

Maintaining shield building OPERABILITY prevents leakage of radioactive material from the shield building. Radioactive material may enter the shield building from the containment following a DBA. Therefore, shield building OPERABILITY is required in MODES 1, 2, 3, and 4 when DBAs could release radioactive material to the containment atmosphere.

In MODES 5 and 6, the probability and consequences of these events are low due to the Reactor Coolant System temperature and pressure limitations in these MODES. Therefore, shield building OPERABILITY is not required in MODE 5 or 6.

ACTIONS

A.1

In the event shield building OPERABILITY is not maintained, shield building OPERABILITY must be restored within 24 hours. 24 hours is a reasonable Completion Time considering the limited leakage design of containment and the low probability of a Design Basis Accident occurring during this time period.

B.1

The Completion Time of 8 hours is based on engineering judgment. The normal alignment for both EGTS control loops is the A-Auto position. With both EGTS control loops in A-Auto, both trains will function upon initiation of a Containment Isolation Phase A (CIA) signal. In the event of a LOCA, the annulus vacuum control system isolates and both trains of the EGTS pressure control loops will be placed in service to maintain the required negative pressure. If annulus vacuum is lost during normal operations, the A-Auto position is unaffected by the loss of vacuum. This operational configuration is acceptable because the accident dose analysis conservatively assumes the annulus is at atmospheric pressure at event initiation. A Note has been provided which makes the requirement to maintain the annulus pressure within limits not applicable during venting operations, required annulus entries, or Auxiliary Building isolations not exceeding 1 hour in duration.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the shield building cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.15.1

Verifying that shield building annulus negative pressure is within limit (equal to or more negative than -5 inches water gauge; value does not account for instrument error) ensures that operation remains within the limit assumed in the containment analysis. The 12-hour Frequency of this SR was developed considering operating experience related to shield building annulus pressure variations and pressure instrument drift during the applicable MODES.

SR 3.6.15.2

Maintaining shield building OPERABILITY requires maintaining each door in the access opening closed, except when the access opening is being used for normal transient entry and exit. The 31-day Frequency of this SR is based on engineering judgment and is considered adequate in view of the other indications of door status that is available to the operator.

SR 3.6.15.3

This SR would give advance indication of gross deterioration of the concrete structural integrity of the shield building. The Frequency of this SR is the same as that of SR 3.6.1.1. The verification is done during shutdown.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.15.4

The EGTS is required to maintain a pressure equal to or more negative than -0.50 inches water gauge (" wg) in the annulus at an elevation equivalent to the top of the Auxiliary Building. At elevations higher than the Auxiliary Building, the EGTS is required to maintain a pressure equal to or more negative than -0.25" wg. The low pressure sense line for the pressure controller is located in the annulus at elevation 783. By verifying that the annulus pressure is equal to or more negative than -0.61" wg at elevation 783, the annulus pressurization requirements stated above are met. The ability of a EGTS train with final flow ≥ 3600 cfm and ≤ 4400 cfm to produce the required negative pressure during the test operation provides assurance that the building is adequately sealed. The negative pressure prevents leakage from the building, since outside air will be drawn in by the low pressure at a maximum rate ≤ 250 cfm. The 18 month Frequency on a STAGGERED TEST BASIS is consistent with Regulatory Guide 1.52 (Ref. 1) guidance for functional testing.

REFERENCES

1. Regulatory Guide 1.52, Revision 2, “Design, Testing and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmospheric Cleanup System Air Filtration and Adsorption Units of Light-Water Cooled Nuclear Power Plants.”

B 3.7 PLANT SYSTEMS

B 3.7.1 Main Steam Safety Valves (MSSVs)

BASES

BACKGROUND

The primary purpose of the MSSVs is to provide overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the reactor coolant pressure boundary (RCPB) by providing a heat sink for the removal of energy from the Reactor Coolant System (RCS) if the preferred heat sink, provided by the Condenser and Circulating Water System, is not available.

Five MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves, as described in the FSAR, Section 10.3.2 (Ref. 1). The MSSVs must have sufficient capacity to limit the secondary system pressure to ≤ 110% of the steam generator design pressure in order to meet the requirements of the ASME Code, Section III (Ref. 2). The MSSV design includes staggered setpoints, according to Table 3.7.1-2 in the accompanying LCO, so that only the needed valves will actuate. Staggered setpoints reduce the potential for valve chattering that is due to steam pressure insufficient to fully open all valves following a turbine reactor trip.

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from Reference 2 and its purpose is to limit the secondary system pressure to ≤ 110% of design pressure for any anticipated operational occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis.

The events that challenge the relieving capacity of the MSSVs, and thus Main Steam System pressure, are those characterized as decreased heat removal events, which are presented in the FSAR, Sections 15.2 and 15.4 (Ref. 3). Of these, the full power loss of normal feedwater is the limiting AOO. The transient response for this event presents no hazard to the integrity of the RCS or the Main Steam System.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Following the loss of continued subcooled feedwater addition, the primary and secondary-side temperatures increase, resulting in a secondary-side pressure increase that proceeds all the way up to the lowest safety valve setpoint. The receipt of a low-low steam generator water level reactor trip signal releases the rod cluster control assemblies (RCCAs) to fall into the core and provides a turbine trip signal. Following the turbine trip, all MSSVs are briefly actuated while rods fall into the core and the hot leg inventory is purged of hot reactor coolant. After the core is shutdown, the required relief capacity is reduced, and one MSSV per steam generator remains open during the remainder of the transient.

In addition to the decreased heat removal events, reactivity insertion events may also challenge the relieving capacity of the MSSVs. The uncontrolled RCCA bank withdrawal at power event is characterized by an increase in core power and steam generation rate until reactor trip occurs when either the Overtemperature ΔT or Power Range Neutron Flux - High setpoint is reached. Steam flow to the turbine will not increase from its initial value for this event. The increased heat transfer to the secondary side causes an increase in steam pressure and may result in opening of the MSSVs prior to reactor trip, assuming no credit for operation of the atmospheric or condenser steam dump valves. The FSAR, Section 15.2 safety analysis of the RCCA bank withdrawal at power event for a range of initial core power levels demonstrates that the MSSVs are capable of preventing secondary side overpressurization for this AOO.

The FSAR safety analyses discussed above assume that all of the MSSVs for each steam generator are OPERABLE. If there are inoperable MSSV(s), it is necessary to limit the primary system power during steady-state operation and AOOs to a value that does not result in exceeding the combined steam flow capacity of the turbine (if available) and the remaining OPERABLE MSSVs. The required limitation on primary system power necessary to prevent secondary system overpressurization may be determined by system transient analyses or conservatively arrived at by a simple heat balance calculation. In some circumstances it is necessary to limit the primary side heat generation that can be achieved during an AOO by reducing the setpoint of the Power Range Neutron Flux - High reactor trip function. For example, if more than one MSSV on a single steam generator is inoperable, an uncontrolled RCCA bank withdrawal at power event occurring from a partial power level may result in an increase in reactor power that exceeds the combined steam flow capacity of the turbine and the remaining OPERABLE MSSVs. Thus, for multiple inoperable MSSVs on the same steam generator it is necessary to prevent this power increase by lowering the Power Range Neutron Flux - High setpoint to an appropriate value.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MSSVs are assumed to have two active failure modes. The active failure modes are spurious opening, and failure to reclose once opened.

The MSSVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The accident analysis requires that five MSSVs per steam generator be OPERABLE to provide overpressure protection for design basis transients occurring at 102% RTP. The LCO requires that five MSSVs per steam generator be OPERABLE in compliance with Reference 2 and the DBA analysis.

The OPERABILITY of the MSSVs is defined as the ability to open upon demand within the setpoint tolerances to relieve steam generator overpressure, and reseat when pressure has been reduced. The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Testing Program.

This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB, or Main Steam System integrity.

APPLICABILITY

In MODES 1, 2, and 3, five MSSVs per steam generator are required to be OPERABLE to prevent Main Steam System overpressurization.

In MODES 4 and 5, there are no credible transients requiring the MSSVs. The steam generators are not normally used for heat removal in MODES 5 and 6, and thus cannot be overpressurized; there is no requirement for the MSSVs to be OPERABLE in these MODES.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

With one or more MSSVs inoperable, action must be taken so that the available MSSV relieving capacity meets Reference 2 requirements.

(continued)

BASES

ACTIONS (continued)

Operation with less than all five MSSVs OPERABLE for each steam generator is permissible, if THERMAL POWER is limited to the relief capacity of the remaining MSSVs. This is accomplished by restricting THERMAL POWER so that the energy transfer to the most limiting steam generator is not greater than the available relief capacity in that steam generator.

A.1

In the case of only a single inoperable MSSV on one or more steam generators, a reactor power reduction alone is sufficient to limit primary side heat generation such that overpressurization of the secondary side is precluded for any RCS heatup event. Furthermore, for this case there is sufficient total steam flow capacity provided by the turbine and remaining OPERABLE MSSVs to preclude overpressuration in the event of an increased reactor power due to reactivity insertion, such as in the event of an uncontrolled RCCA bank withdrawal at power. Therefore, Required Action A.1, requires an appropriate reduction in reactor power within 4 hours.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined using a conservative heat balance between the reactor coolant system heat generation and the steam relief through the OPERABLE MSSVs, as shown below and described in the attachment to Reference 5:

$$\textit{Allowable THERMAL POWER Level (\%)} = 100\frac{4\, w_s\, h_{fg}}{QK}$$

where: w_s = Minimum total steam relief capacity of the OPERABLE MSSVs on any one steam generator, in lbm/sec.

h_{fg} = heat of vaporization at the highest MSSV full-open pressure, in Btu/lbm.

Q = NSSS power rating of the plant (includes reactor coolant pump heat), in MWt.

K = Unit conversion factor: 947.82 Btu/sec/MWt.

Note: The values in Specification 3.7.1 include an allowance for instrument and channel uncertainties to the allowable RTP obtained with this algorithm.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

In the case of multiple inoperable MSSVs on one or more steam generators, with a reactor power reduction alone there may be insufficient total steam flow capacity provided by the turbine and remaining OPERABLE MSSVs to preclude overpressurization in the event of an increased reactor power due to reactivity insertion, such as in the event of an uncontrolled RCCA bank withdrawal at power. The 4 hour Completion Time for Required Action B.1 is consistent with A.1. An additional 32 hours is allowed in Required Action B.2 to reduce the setpoints. The Completion Time of 36 hours is based on a reasonable time to correct the MSSV inoperability, the time required to perform the power reduction, operating experience in resetting all channels of a protective function, and on the low probability of the occurrence of a transient that could result in steam generator overpressure during this period.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined using a conservative heat balance calculation as described above (Action A.1) and in the attachment to Reference 5. The values in Specification 3.7.1 include an allowance for instrument and channel uncertainties to the allowable RTP obtained with this algorithm.

Required Action B.2 is modified by a Note, indicating that the Power Range Neutron Flux - High reactor trip setpoint reduction is only required in MODE 1. In MODES 2 and 3, the reactor protection system trips specified in LCO 3.3.1, “Reactor Trip System Instrumentation,” provide sufficient protection.

C.1 and C.2

If the Required Actions are not completed within the associated Completion Time, or if one or more steam generators have ≥ 4 inoperable MSSVs, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME OM Code (Ref. 4) requires that safety and relief valve tests be performed as follows:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting); and

d. Compliance with owner's seat tightness criteria.

The ASME OM Code requires that all valves be tested every 5 years, and a minimum of 20% of the valves be tested every 24 months. Additional test frequency requirements apply during the initial five year period as discussed in Reference 4. The ASME OM Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7.1-2 allows a ± 3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift. The lift settings, according to Table 3.7.1-2 correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected to ambient conditions of the valve at operating temperature and pressure.

BASES (continued)

REFERENCES

1. Watts Bar FSAR, Section 10.3, “Main Steam Supply System.”

2. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section III, Article NC-7000, “Overpressure Protection,” Class 2 Components.

3. Watts Bar FSAR, Section 15.2, “Condition II - Faults of Moderate Frequency,” and Section 15.4, “Condition IV - Limiting Faults.”

4. American Society of Mechanical Engineers (ASME) OM Code, “Code for Operation and Maintenance of Nuclear Power Plants.”

5. NRC Information Notice 94-60, “Potential Overpressurization of Main Steam System,” August 22, 1994.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

The MSIVs isolate steam flow from the secondary side of the steam generators following a high energy line break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generators.

One MSIV is located in each main steam line outside, but close to, containment. The MSIVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV and AFW isolation from the steam generators by MSIV closure. Closing the MSIVs isolates each steam line from the others, and isolates the turbine, Steam Dump System, and other auxiliary steam supplies from the steam generators.

The MSIVs close on a main steam isolation signal generated by either low steam line pressure, high negative steam pressure rate (below P-11), or high-high containment pressure. The MSIVs fail closed on loss of control or actuation power.

Each MSIV has an MSIV bypass valve. Although these bypass valves are normally closed, they receive the same emergency closure signal as do their associated MSIVs. The MSIVs may also be actuated manually.

A description of the MSIVs is found in the FSAR, Section 10.3 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment, discussed in the FSAR, Section 6.2 (Ref. 2). It is also affected by the accident analysis of the SLB events presented in the FSAR, Section 15.4.2.1 (Ref. 3). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand).

The limiting case for the containment analysis is the SLB inside containment, with a loss of offsite power following turbine trip, and failure of the MSIV on the affected steam generator to close. At lower powers, the steam generator inventory and temperature are at their maximum, maximizing the analyzed mass and energy release to the containment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Due to reverse flow and failure of the MSIV to close, the additional mass and energy in the steam headers downstream from the other MSIV contribute to the total release. With the most reactive rod cluster control assembly assumed stuck in the fully withdrawn position, there is an increased possibility that the core will become critical and return to power. The core is ultimately shut down by the boric acid injection delivered by the Emergency Core Cooling System.

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB inside containment at hot zero power is the limiting case for a post trip return to power. The analysis includes scenarios with offsite power available, and with a loss of offsite power following turbine trip. With offsite power available, the reactor coolant pumps continue to circulate coolant through the steam generators, maximizing the Reactor Coolant System cooldown. With a loss of offsite power, the response of mitigating systems is delayed. Significant single failures considered include failure of an MSIV to close.

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. An HELB inside containment. In order to maximize the mass and energy release into containment, the analysis assumes that the MSIV in the affected steam generator remains open. For this accident scenario, steam is discharged into containment from all steam generators until the remaining MSIVs close. After MSIV closure, steam is discharged into containment only from the affected steam generator and from the residual steam in the main steam header downstream of the closed MSIVs in the unaffected loops. Closure of the MSIVs isolates the break from the unaffected steam generators.

b. A break outside of containment and upstream from the MSIVs is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs isolates the break and limits the blowdown to a single steam generator.

c. A break downstream of the MSIVs will be isolated by the closure of the MSIVs.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

d. Following a steam generator tube rupture, closure of the MSIVs isolates the ruptured steam generator from the intact steam generators to minimize radiological releases.

e. The MSIVs are also utilized during other events such as a feedwater line break. This event is less limiting so far as MSIV OPERABILITY is concerned.

The MSIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that four MSIVs in the steam lines be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 100 (Ref. 4) limits or the NRC staff approved licensing basis.

APPLICABILITY

The MSIVs must be OPERABLE in MODE 1, and in MODES 2 and 3 except when closed and de-activated, when there is significant mass and energy in the RCS and steam generators. When the MSIVs are closed, they are already performing the safety function.

In MODE 4, normally most of the MSIVs are closed, and the steam generator energy is low.

In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

BASES (continued)

ACTIONS

A.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 8 hours. Some repairs to the MSIV can be made with the unit hot. The 8-hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs.

The 8-hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a closed system penetrating containment. These valves differ from other containment isolation valves in that the closed system provides an additional means for containment isolation.

B.1

If the MSIV cannot be restored to OPERABLE status within 8 hours, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in MODE 2 within 6 hours and Condition C would be entered. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging plant systems.

C.1 and C.2

Condition C is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 8-hour Completion Time is consistent with that allowed in Condition A.

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSIVs must be verified on a periodic basis to be closed and de-activated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7-day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the MSIVs cannot be restored to OPERABLE status or are not closed within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from MODE 2 conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is ≤ 6.0 seconds on an actual or simulated actuation signal. The MSIV closure time is assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage.

The Frequency is in accordance with the Inservice Testing Program or 18 months. The 18 month Frequency for valve closure time is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This test is conducted in MODE 3 with the unit at operating temperature and pressure, as discussed in Reference 5 exercising requirements. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

REFERENCES

1. Watts Bar FSAR, Section 10.3, “Main Steam Supply System.”
2. Watts Bar FSAR, Section 6.2, “Containment Systems.”
3. Watts Bar FSAR, Section 15.4.2.1, “Major Rupture of a Main Steam Line.”
4. 10 CFR 100.11.
5. American Society of Mechanical Engineers (ASME) OM Code, “Code for Operation and Maintenance of Nuclear Power Plants.”

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Feedwater Isolation Valves (MFIVs) and Main Feedwater Regulation Valves (MFRVs) and Associated Bypass Valves

BASES

BACKGROUND

The MFRVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). The safety related function of the MFIVs is to provide the second isolation of MFW flow to the secondary side of the steam generators following an HELB. Closure of the MFIVs and associated bypass valves or MFRVs and associated bypass valves terminates flow to the steam generators. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the MFIVs will be mitigated by their closure. Closure of the MFIVs and associated bypass valves, or MFRVs and associated bypass valves, effectively terminates the addition of normal feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or feedwater line breaks (FWLBs) inside containment, and reducing the cooldown effects for SLBs.

The MFIVs and associated bypass valves, isolate the non-safety related portions from the safety related portions of the system. In the event of a secondary side pipe rupture inside containment, the valves limit the quantity of high energy fluid that enters containment through the break.

One MFIV and one MFRV are located on each 16-inch MFW line. One bypass MFRV and one bypass MFIV are located on a smaller 6-inch startup and tempering flow feedwater line. Both the MFIV and bypass MFIV are located in the main steam valve vault close to containment.

The MFIVs and associated bypass valves, and MFRVs and associated bypass valves, close on receipt of a T_{avg} Low coincident with reactor trip (P-4), safety injection signal, or steam generator water level - high high signal. They may also be closed manually except for the bypass MFIV which has no handswitch. In addition to the MFIVs and associated bypass valves, and the MFRVs and associated bypass valves, a check valve on the 16-inch MFW line is located just outside containment in the main steam valve vault. The check valve terminates flow from the steam generator for breaks upstream of the check valve.

A description of the MFIVs and MFRVs is found in the FSAR, Section 10.4.7 (Ref. 1).

BASES (continued)

APPLICABLE SAFETY ANALYSES

The design basis of the MFIVs and MFRVs and associated bypass valves is established by the analyses for the large SLB. It is also influenced by the accident analysis for the large FWLB. Closure of the MFIVs and associated bypass valves, or MFRVs and associated bypass valves, may also be relied on to mitigate an SLB for core response analysis and excess feedwater event.

Failure of an MFIV, MFRV, or the associated bypass valves in a single flow path to close following an SLB or FWLB can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following an SLB or FWLB event.

The MFIVs and MFRVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO ensures that the MFIVs, MFRVs, and their associated bypass valves will isolate MFW flow to the steam generators, following an FWLB or SLB. The MFIVs and bypass MFIVs will also isolate the non-safety related portions from the safety related portions of the system.

This LCO requires that four MFIVs and associated bypass valves and four MFRVs and associated bypass valves be OPERABLE. The MFIVs and MFRVs and the associated bypass valves are considered OPERABLE when isolation times are within limits and they close on an isolation actuation signal.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or FWLB inside containment. If a feedwater isolation signal on high - high steam generator level is relied on to terminate an excess feedwater flow event, failure to meet the LCO may result in the introduction of water into the main steam lines.

BASES (continued)

APPLICABILITY

The MFIVs and MFRVs and the associated bypass valves must be OPERABLE whenever there is significant mass and energy in the Reactor Coolant System and steam generators. This ensures that, in the event of an HELB, a single failure cannot result in the blowdown of more than one steam generator. In MODES 1, 2, and 3, the MFIVs and MFRVs and the associated bypass valves are required to be OPERABLE, except when closed and de-activated to limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment. When the valves are closed and de-activated or isolated by a closed manual valve, they are already performing their safety function.

In MODES 4, 5, and 6, steam generator energy is low. Therefore, the MFIVs, MFRVs, and the associated bypass valves are normally closed since MFW is not required.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each valve.

A.1 and A.2

With one MFIV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFIVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

With one MFRV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFRVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid.
The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls to ensure that the valves are closed or isolated.

C.1

With one MFIV or MFRV bypass valve in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status within 72 hours. The inoperable valve should not be closed and isolated for long periods of time since the 6-inch bypass line provides a small tempering flow to the upper SG nozzle. This limits the temperature difference between the SG and condensate storage tank fluid which would be supplied by the AFW system. The 6-inch line may be isolated for short periods of time to support calorimetric flow measurements.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

(continued)

BASES

ACTIONS (continued)

D.1

With an MFIV and an MFRV in the same flow path inoperable, there may be no redundant system to operate automatically and perform the required safety function. Under these conditions, at least one valve in the flow path must be restored to OPERABLE status, or the affected flow path isolated within 8 hours. This action returns the system to the condition where at least one valve in each flow path is performing the required safety function. The 8 hour Completion Time is reasonable, based on operating experience, to complete the actions required to close the MFIV or MFRV, or otherwise isolate the affected flow path.

E.1

With two bypass valves in the same flow path inoperable, there may be no redundant system to operate automatically and perform the required safety function. Under these conditions, at least one valve in the flow path must be restored to OPERABLE status within 8 hours. The Completion Time of 8 hours is consistent with Condition D.

F.1 and F.2

If the MFIV(s) and MFRV(s) and the associated bypass valve(s) cannot be restored to OPERABLE status, or the MFIV(s) or MFRV(s) closed, or isolated within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that the closure time of each MFIV, MFRV, and associated bypass valves is ≤ 6.5 seconds on an actual or simulated actuation signal. The MFIV and MFRV closure times are assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. These valves should not be tested at power since even a part stroke exercise increases the risk of a valve closure with the unit generating power. This is consistent with the American Society of Mechanical Engineers (ASME) OM Code (Ref. 2), quarterly stroke requirements during operation in MODES 1 and 2.

The Frequency for this SR is in accordance with the Inservice Testing Program or 18 months. The 18 month Frequency for valve closure is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. FSAR, Section 10.4.7, “Condensate and Feedwater Systems.”

2. American Society of Mechanical Engineers (ASME) OM Code, “Code for Operation and Maintenance of Nuclear Power Plants.”

B 3.7 PLANT SYSTEMS

B 3.7.4 Atmospheric Dump Valves (ADVs)

BASES

BACKGROUND

The ADVs provide a method for cooling the unit to residual heat removal (RHR) entry conditions should the preferred heat sink via the Steam Dump System to the condenser not be available, as discussed in the FSAR, Section 10.3 (Ref. 1). This is done in conjunction with the Auxiliary Feedwater System providing cooling water from the condensate storage tank (CST). The ADVs may also be required to meet the design cooldown rate during a normal cooldown when steam pressure drops too low for maintenance of a vacuum in the condenser to permit use of the Steam Dump System.

One ADV line for each of the four steam generators is provided. Each ADV line consists of one ADV and an associated block valve.

The ADVs are provided with upstream block valves to permit their being tested at power, and to provide an alternate means of isolation. The ADVs are equipped with pneumatic controllers to permit control of the cooldown rate.

The ADVs are provided with a pressurized air supply from the auxiliary air compressors that, on a loss of pressure in the normal instrument air supply, automatically supplies backup air to operate the ADVs. The ADVs are also supplied with nitrogen to permit local operation outside the valve rooms.

A description of the ADVs is found in Reference 1. The ADVs are OPERABLE with a DC power source and control air available. In addition, handwheels are provided for local manual operation.

APPLICABLE SAFETY ANALYSES

The design basis of the ADVs is established by the capability to cool the unit to RHR entry conditions. The capacity of the ADVs is sufficient to achieve a cooldown rate of 50°F/hr throughout the entire cooldown to RHR entry conditions with 2 ADVs in service. This permits a uniform cooldown within the capacity of the cooling water supply available in the CST.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

In the accident analysis presented in Chapter 15.0 of the FSAR (Ref. 2), the ADVs are assumed to be used by the operator to cool down the unit to RHR entry conditions for accidents accompanied by a loss of offsite power. Prior to operator actions to cool down the unit, the main steam safety valves (MSSVs) are assumed to operate automatically to relieve steam and maintain the steam generator pressure below the design value. For the recovery from a steam generator tube rupture (SGTR) event, the operator is also required to perform a limited cooldown to establish adequate subcooling as a necessary step to terminate the primary to secondary break flow into the ruptured steam generator. The time required to terminate the primary to secondary break flow for an SGTR is more critical than the time required to cool down to RHR conditions for this event and also for other accidents. Thus, the SGTR is the limiting event for the ADVs. Four ADVs are required to be OPERABLE to satisfy the SGTR accident analysis requirements. This considers any single failure assumptions regarding the failure of one ADV to open on demand.

The ADVs are equipped with block valves in the event an ADV spuriously fails to open or fails to close during use.

The ADVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Four ADV lines are required to be OPERABLE. One ADV line is required from each of four steam generators to ensure that at least two ADV lines are available to conduct a unit cooldown following an SGTR, in which one steam generator becomes unavailable, accompanied by a single, active failure of a second ADV line on an unaffected steam generator. The block valves must be OPERABLE to isolate a failed open ADV line.

Failure to meet the LCO can result in a delay in completing the SGTR recovery operations which could result in dose consequences that exceed accident analysis criteria.

An ADV is considered OPERABLE when it is capable of providing controlled relief of the main steam flow and capable of fully opening and closing on demand.

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when a steam generator is being relied upon for heat removal, the ADVs are required to be OPERABLE.

In MODE 5 or 6, an SGTR is not a credible event.

BASES (continued)

ACTIONS

A.1

With one required ADV line inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time allows for the redundant capability afforded by the remaining OPERABLE ADV lines, a non-safety grade backup in the Steam Dump System, and MSSVs.

B.1

The four ADVs are supplied with safety-related Train A and Train B control air by the Auxiliary Control Air System (ACAS). Two valves receive Train A air and two valves receive Train B air. With one train (two ADV lines) inoperable due to an inoperable ACAS train, action must be taken to restore operability of the ACAS train to ensure operability of the ADV lines. The 72 hour Completion Time is reasonable since alternate means are available to operate the ADVs assuming an inoperable ACAS train, and the low probability of an event occurring during this period that would require the ADV lines. Normal control air is used to operate the valves, if available. In addition, the ADVs can be manually operated with the valve hand wheel, or by manually aligning a bottled nitrogen system to the valve operators. Each ADV is provided with a main and alternate nitrogen bottle designed to operate the valves if normal and emergency air supplies are lost. Further, the MSSVs will provide system over pressure protection if the ADVs fail to function, and the condenser steam dump valves will normally be available for plant cooldown.

C.1

With two or more ADV lines inoperable, action must be taken to restore all but one ADV line to OPERABLE status. Since the block valve can be closed to isolate an ADV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable ADV lines, based on the availability of the Steam Dump System and MSSVs, and the low probability of an event occurring during this period that would require the ADV lines.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the ADV lines cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance upon steam generator for heat removal, within 18 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 3.7.4.1

To perform a controlled cooldown of the RCS, the ADVs must be able to be opened either remotely or locally and throttled through their full range. This SR ensures that the ADVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing or use of an ADV during a unit cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. The Frequency is acceptable from a reliability standpoint.

SR 3.7.4.2

The function of the block valve is to isolate a failed open ADV. Cycling the block valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the block valve during unit cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency. The Frequency is acceptable from a reliability standpoint.

REFERENCES

1. Watts Bar FSAR, Section 10.3, “Main Steam Supply System.”
2. Watts Bar FSAR, Section 15.0, “Accident Analysis.”

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply. The AFW pumps take suction from the condensate storage tank (CST) (LCO 3.7.6) and pump to the steam generator secondary side via separate connections to the main feedwater (MFW) bypass line piping. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) (LCO 3.7.1) or atmospheric dump valves (LCO 3.7.4). If the main condenser is available, steam may be released via the steam dump valves and recirculated to the CST.

The AFW System consists of two motor driven AFW pumps and one steam turbine driven pump configured into three trains. Each motor driven pump provides 410 gpm of AFW flow, and the turbine driven pump provides 720 gpm to the steam generators, as assumed in the accident analysis. The pumps are equipped with independent recirculation lines to prevent pump operation against a closed system. Each motor driven AFW pump is powered from an independent Class 1E power supply and feeds two steam generators. The steam turbine driven AFW pump receives steam from one of two main steam lines upstream of the main steam isolation valves. Each of the steam feed lines will supply 100% of the requirements of the turbine driven AFW pump.

The AFW System is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions; however, the Main Feedwater System will normally perform these functions.

The turbine driven AFW pump supplies a common header capable of feeding all steam generators. One pump at full flow is sufficient to remove decay heat and cool the unit to residual heat removal (RHR) entry conditions. Thus, the requirement for diversity in motive power sources for the AFW System is met.

(continued)

BASES

BACKGROUND (continued)

The AFW System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the lowest setpoint (plus 3% tolerance plus 3% accumulation) of the MSSVs. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the ADVs.

The AFW System actuates automatically on steam generator water level – low-low by the ESFAS (LCO 3.3.2). The motor driven pumps start on a two-out-of-three low-low level signal in any steam generator and the turbine driven pump starts on a two-out-of-three low-low level signal in any two steam generators. The system also actuates on loss of offsite power, safety injection, and trip of both turbine-driven MFW pumps.

The AFW System is discussed in the FSAR, Section 10.4.9 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest steam generator safety valve set pressure plus 3% tolerance plus 3% accumulation.

In addition, the AFW System must supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting Design Basis Accidents (DBAs) and transients for the AFW System are as follows:

a. Feedwater Line Break (FWLB); and

b. Loss of MFW.

In addition, the minimum available AFW flow and system characteristics are serious considerations in the analysis of a small break loss of coolant accident (LOCA).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The AFW System design is such that it can perform its function following an FWLB between the MFW check valves and the steam generators, combined with a loss of offsite power following turbine trip, and a single active failure of the steam turbine driven AFW pump. One motor driven AFW pump would deliver to the faulted steam generator. Sufficient flow would be delivered to the intact steam generators by the redundant AFW pump.

The ESFAS automatically actuates the AFW turbine driven pump and associated power operated valves and controls when required to ensure an adequate feedwater supply to the steam generators during loss of power.

Each motor driven auxiliary feedwater pump (one Train A and one Train B) supplies flow paths to two steam generators. Each flow path contains automatic air-operated level control valves (LCVs). The LCVs have the same train designation as the associated pump and are provided trained air. The turbine-driven auxiliary feedwater pump supplies flow paths to all four steam generators. Each of these flow paths contains an automatic air-operated LCV, two of which are designated as Train A, receive A-train air and provide flow to the same steam generators that are supplied by the B-train motor driven auxiliary feedwater pump. The remaining two LCVs are designated as Train B, receive B-train air, and provide flow to the same steam generators that are supplied by the A-train motor driven pump. This design provides the required redundancy to ensure that at least two steam generators receive the necessary flow assuming any single failure. It can be seen from the description provided above that the loss of a single train of air (A or B) will not prevent the auxiliary feedwater system from performing its intended safety function and is no more severe than the loss of a single auxiliary feedwater pump. Therefore, the loss of a single train of auxiliary air only affects the capability of a single motor driven auxiliary feedwater pump because the turbine-driven pump is still capable of providing flow to the two steam generators that are separated from the other motor driven pump.

The AFW System satisfies the requirements of Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary. Three independent AFW pumps in three diverse trains are required to be OPERABLE to ensure the availability of RHR capability for all events accompanied by a loss of offsite power and a single failure. This is accomplished by powering two of the pumps from independent emergency buses. The third AFW pump is powered by a different means, a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs.

The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. This requires that the two motor driven AFW pumps be OPERABLE in two diverse paths, each supplying AFW to separate steam generators. The turbine driven AFW pump is required to be OPERABLE with redundant steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of supplying AFW to any of the steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE.

The LCO is modified by a Note indicating that one AFW train, which includes a motor driven pump, is required to be OPERABLE in MODE 4. This is because of the reduced heat removal requirements and short period of time in MODE 4 during which the AFW is required and the insufficient steam available in MODE 4 to power the turbine driven AFW pump.

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW is lost. In addition, the AFW System is required to supply enough makeup water to replace the steam generator secondary inventory, lost as the unit cools to MODE 4 conditions.

In MODE 4, the AFW System may be used for heat removal via the steam generators.

In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.

BASES

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable AFW train when entering MODE 1. There is an increased risk associated with entering MODE 1 with an AFW train inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

If one of the two steam supplies to the turbine driven AFW train is inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. The redundant OPERABLE steam supply to the turbine driven AFW pump;

b. The availability of redundant OPERABLE motor driven AFW pumps; and

c. The low probability of an event occurring that requires the inoperable steam supply to the turbine driven AFW pump.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation on the time allowed in this 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 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

B.1

With one of the required AFW trains (pump or flow path) inoperable in MODE 1, 2, or 3 for reasons other than Condition A, action must be taken to restore OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to the turbine driven AFW pump. The 72 hour Completion Time is reasonable, based on redundant capabilities afforded by the AFW System, time needed for repairs, and the low probability of a DBA occurring during this time period.

(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 Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation on the time allowed in this 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 72 hours and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

C.1 and C.2

When Required Action A.1 or B.1 cannot be completed within the required Completion Time, or if two AFW trains are inoperable in MODE 1, 2, or 3, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 18 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.

In MODE 4 with two AFW trains inoperable, operation is allowed to continue because only one motor driven pump AFW train is required in accordance with the Note that modifies the LCO. Although not required, the plant may continue to cool down and initiate RHR.

D.1

If all three AFW trains are inoperable in MODE 1, 2, or 3, the plant is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with non-safety related equipment. In such a condition, the unit should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one AFW train to OPERABLE status.

Required Action D.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one AFW train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the plant into a less safe condition.

(continued)

BASES

ACTIONS (continued)

E.1

In MODE 4, either the reactor coolant pumps or the RHR loops can be used to provide forced circulation. This is addressed in LCO 3.4.6, "RCS Loops - MODE 4." With one required AFW train inoperable, action must be taken to immediately restore the inoperable train to OPERABLE status. The immediate Completion Time is consistent with LCO 3.4.6. Automatic actuation of AFW is not required in MODE 4; therefore, AFW/ERCW interface valves are not required to be in service.

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the AFW System water and steam supply flow paths provides assurance that the proper flow paths exist for AFW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.5.2

Verifying that each AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of centrifugal pump performance required by American Society of Mechanical Engineers (ASME) OM Code (Ref. 2). Because it is undesirable to introduce cold AFW into the steam generators while they are operating, this testing is performed on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing discussed in the ASME OM Code (Ref. 2) (only required at 3 month intervals) satisfies this requirement. The 31 day Frequency on a STAGGERED TEST BASIS results in testing each pump once every 3 months, as required by Reference 2.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.2 (continued)

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions are established. This deferral is required because there may be insufficient steam pressure to perform the test.

SR 3.7.5.3

This SR verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an ESFAS, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative control. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 18 month Frequency is acceptable based on operating experience and the design reliability of the equipment. This SR is modified by a Note that states that the SR is not required in MODE 4. MODE 4 does not require automatic activation of the AFW because there is a sufficient time frame for operator action. This is based on the fact that even at 0% power (MODE 3) there is approximately a 10 minute trip time logic delay before actuation of the AFW system to allow for operator action. In MODE 4, the heat removal requirements would be less providing more time for operator action.

SR 3.7.5.4

This SR verifies that the AFW pumps will start in the event of any accident or transient that generates an ESFAS by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.4 (continued)

This SR is modified by two Notes. Note 1 indicates that the SR be deferred until suitable test conditions are established. This deferral is required because there may be insufficient steam pressure to perform the test. Note 2 states that the SR is not required in MODE 4. MODE 4 does not require automatic activation of the AFW because there is a sufficient time frame for operator action. This is based on the fact that even at 0% power (MODE 3) there is approximately a 10 minute trip time logic delay before actuation of the AFW system to allow for operator action. In MODE 4, the heat removal requirements would be less providing more time for operator action.

SR 3.7.5.5

This SR verifies that the AFW is properly aligned by verifying the flow through the flow paths from the CST to each steam generator prior to entering MODE 2 after initial fuel loading and prior to subsequent entry into MODE 2 whenever the unit has been in any combination of MODES 5 or 6 for greater than 30 days. Operability of AFW flow paths must be verified before sufficient core heat is generated that would require the operation of the AFW System during a subsequent shutdown. The Frequency is reasonable, based on engineering judgment and other administrative controls that ensure that flow paths remain OPERABLE. To further ensure AFW System alignment, flow path OPERABILITY is verified following extended outages to determine no misalignment of valves has occurred. This SR ensures that the flow path from the CST to the steam generators is properly aligned.

REFERENCES

1. Watts Bar FSAR, Section 10.4.9, "Auxiliary Feedwater System."

2. American Society of Mechanical Engineers (ASME) OM Code, "Code for Operation and Maintenance of Nuclear Power Plants."

B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage Tank (CST)

BASES

BACKGROUND

The CST provides a preferred source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The CST provides a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (LCO 3.7.5). The steam produced is released to the atmosphere by the main steam safety valves or the atmospheric dump valves. The AFW pumps operate with a continuous recirculation to the CST.

When the main steam isolation valves are open, the preferred means of heat removal is to discharge steam to the condenser by the non-safety grade path of the steam dump valves. The condensed steam is returned to the CST by the condenser level control valves. This has the advantage of conserving condensate while minimizing releases to the environment.

Because the CST is not designed to withstand earthquakes and other natural phenomena, including missiles that might be generated by natural phenomena, feedwater is also available from the Essential Raw Cooling Water (ERCW) System as the safety grade water source.

A description of the CST is found in the FSAR, Section 9.2.6 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The CST provides the preferred cooling water to remove decay heat and to cool down the unit following all events in the accident analysis as discussed in the FSAR, Chapters 6 and 15 (Refs. 2 and 3, respectively). However, the ERCW System provides the safety grade water source to meet a DBA should the CST become unavailable. For anticipated operational occurrences and accidents that do not affect the OPERABILITY of the steam generators, the analysis assumption is generally 2 hours at MODE 3, steaming through the MSSVs, followed by a cooldown to residual heat removal (RHR) entry conditions at the design cooldown rate.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting event for the condensate volume is the large feedwater line break coincident with a loss of offsite power. Single failures that also affect this event include the following:

a. Failure of the diesel generator powering the motor driven AFW pump to the unaffected steam generators (requiring additional steam to drive the remaining AFW pump turbine); and

b. Failure of the steam driven AFW pump (requiring a longer time for cooldown using only one motor driven AFW pump).

These are not usually the limiting failures in terms of consequences for these events.

A non-limiting event considered in CST inventory determinations is a break in either the main feedwater bypass line or AFW line near where the two join. This break has the potential for dumping condensate until terminated by operator action. This loss of condensate inventory is partially compensated for by the retention of steam generator inventory.

Because the CST is the preferred source of feedwater and is relied on almost exclusively for accidents and transients, the CST satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

As the preferred water source to satisfy accident analysis assumptions, the CST must contain sufficient cooling water to remove decay heat for 2 hours following a reactor trip from 102% RTP, and then to cool down the RCS to RHR entry conditions, assuming a coincident loss of offsite power and the most adverse single failure. In doing this, it must retain sufficient water to ensure adequate net positive suction head for the AFW pumps during cooldown, as well as account for any losses from the steam driven AFW pump turbine, or before isolating AFW to a broken line.

The CST level required is equivalent to a usable volume of ≥ 200,000 gallons, which is based on holding the unit in MODE 3 for 2 hours, followed by a cooldown to RHR entry conditions at 50°F/hour. This basis is established in Reference 4 and exceeds the volume required by the accident analysis.

The OPERABILITY of the CST is determined by maintaining the tank level at or above the minimum required level.

BASES (continued)

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when steam generator is being relied upon for heat removal, the CST is required to be OPERABLE.

In MODE 5 or 6, the CST is not required because the AFW System is not required.

ACTIONS

A.1 and A.2

If the CST level is not within limits, the OPERABILITY of the backup supply should be verified by administrative means within 4 hours and once every 12 hours thereafter. OPERABILITY of the backup feedwater supply must include verification that the flow paths from the backup water supply to the AFW pumps are OPERABLE. The CST must be restored to OPERABLE status within 7 days, because the backup supply may be performing this function in addition to its normal functions. The 4 hour Completion Time is reasonable, based on operating experience, to verify the OPERABILITY of the backup water supply. The 7 day Completion Time is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period requiring the CST.

B.1 and B.2

If the CST cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance on the steam generator for heat removal, within 18 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 3.7.6.1

This SR verifies that the CST contains a volume of ≥ 200,000 gallons (value accounts for instrument error) of cooling water. The 12 hour Frequency is based on operating experience and the need for operator awareness of unit evolutions that may affect the CST inventory between checks. Also, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to abnormal deviations in the CST level.

BASES (continued)

REFERENCES

1. Watts Bar FSAR, Section 9.2.6, “Condensate Storage Facilities.”
2. Watts Bar FSAR, Chapter 6, “Engineered Safety Features.”
3. Watts Bar FSAR, Chapter 15, “Accident Analyses.”
4. TVA Calculation 0-HCG-LCS-043085, “Minimum CST Water Level Required to Support the AFW System.”

B 3.7 PLANT SYSTEMS

B 3.7.7 Component Cooling System (CCS)

BASES

BACKGROUND

The CCS provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, the CCS also provides this function for various non-essential components, as well as the spent fuel storage pool. The CCS serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Essential Raw Cooling Water (ERCW) System, and thus to the environment.

The CCS is arranged as two independent, full-capacity cooling trains, Train A and Train B. Train A in Unit 2 is served by CCS Hx B and CCS pump 2A-A. Pump 2B-B, which is actually Train B equipment, is also normally aligned to the Train A header in Unit 2. However, pump 2B-B can be realigned to Train B on loss of Train A.

Train B is served by CCS Hx C. Normally, only CCS pump C-S is aligned to the Train B header since few non-essential, normally-operating loads are assigned to Train B. However, pump 2B-B can be realigned to the Train B header on a loss of the C-S pump.

Each safety related train is powered from a separate bus. An open surge tank in the system provides pump trip protective functions to ensure that sufficient net positive suction head is available. The pump in each train is automatically started on receipt of a safety injection signal, and all non-essential components will be manually isolated.

CCS Pump 1B-B may be substituted for CCS Pump C-S supplying the CCS Train B header for Unit 2 provided the OPERABILITY requirements are met.

Additional information on the design and operation of the system, along with a list of the components served, is presented in the FSAR, Section 9.2.2 (Ref. 1). The principal safety related function of the CCS is the removal of decay heat from the reactor via the Residual Heat Removal (RHR) System. This may be during a normal or post accident cooldown and shutdown.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The design basis of the CCS is for one CCS train to remove the post loss of coolant accident (LOCA) heat load from the containment sump during the recirculation phase, with a maximum CCS temperature of 110 °F (Ref. 2). The Emergency Core Cooling System (ECCS) LOCA and containment OPERABILITY LOCA each model the maximum and minimum performance of the CCS, respectively. The normal temperature of the CCS is 95 °F, and, during unit cooldown to MODE 5 (T_{cold} < 200 °F), a maximum temperature of 110°F is assumed. The CCS design based on these values, bounds the post accident conditions such that the sump fluid will not increase in temperature after alignment of the RHR heat exchangers during the recirculation phase following a LOCA, and provides a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System (RCS) by the ECCS pumps.

The CCS is designed to perform its function with a single failure of any active component, assuming a loss of offsite power.

The CCS also functions to cool the unit from RHR entry conditions (T_{cold} < 350 °F), to MODE 5 (T_{cold} < 200 °F), during normal and post accident operations. The time required to cool from 350 °F to 200 °F is a function of the number of CCS and RHR trains operating. One CCS train is sufficient to remove decay heat during subsequent operations with T_{cold} < 200 °F. This assumes a maximum ERCW temperature of 85 °F occurring simultaneously with the maximum heat loads on the system.

The CCS satisfies Criterion 3 of 10 CFR 50.36 (c)(2)(ii).

LCO

The CCS trains are independent of each other to the degree that each has separate controls and power supplies and the operation of one does not depend on the other. In the event of a DBA, one CCS train is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two trains of CCS must be OPERABLE. At least one CCS train will operate assuming the worst case single active failure occurs coincident with a loss of offsite power.

A CCS train is considered OPERABLE when:

a. The pump and associated surge tank are OPERABLE; and

b. The associated piping, valves, heat exchanger, and instrumentation and controls required to perform the safety related function are OPERABLE.

(continued)

BASES

LCO (continued)

c. If CCS Pump 1B-B is substituted for CCS Pump C-S supplying the CCS Train B header for Unit 2, CCS Pump 1B-B is only considered OPERABLE when aligned to the CCS Train B header and operating.

The isolation of CCS from other components or systems not required for safety may render those components or systems inoperable but does not affect the OPERABILITY of the CCS.

CCS Pump 1B-B only receives a safety injection (SI) signal from Unit 1. If CCS Pump 1B-B is in a standby mode and is aligned as a substitute for CCS Pump C-S, then CCS Train B will not be OPERABLE for Unit 2. Conversely, if CCS Pump 1B-B is operating and aligned as a substitute for CCS Pump C-S supplying the CCS Train B header, then CCS Train B is OPERABLE for Unit 2. The presence of an SI signal in Unit 2 will have no effect on CCS Pump 1B-B and the pump will continue to operate. In the event of a loss of offsite power, with or without an SI signal present, CCS Pump 1B-B will be automatically sequenced onto its respective diesel generator and continue to perform its required safety function.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CCS is a normally operating system, which must be prepared to perform its post accident safety functions, primarily RCS heat removal, which is achieved by cooling the RHR heat exchanger.

In MODE 5 or 6, the OPERABILITY requirements of the CCS are determined by the systems it supports.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.6, “RCS Loops - MODE 4,” be entered if an inoperable CCS train results in an inoperable RHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

If one CCS train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE CCS train is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the CCS train cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 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 3.7.7.1

This SR verifies that the C-S pump is powered from the normal power source when it is aligned for OPERABLE status. Verification of the correct power alignment ensures that the two CCS trains remain independent. The 7 day Frequency is based on engineering judgment, is consistent with procedural controls governing breaker operation, and ensures correct breaker position.

SR 3.7.7.2

This SR is modified by a Note indicating that the isolation of the CCS flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CCS.

Verifying the correct alignment for manual, power operated, and automatic valves in the CCS flow path provides assurance that the proper flow paths exist for CCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.3

This SR verifies proper automatic operation of the CCS valves on an actual or simulated actuation signal. The CCS is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative control. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit 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. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.7.4

This SR verifies proper automatic operation of the CCS pumps on an actual or simulated actuation signal. The CCS is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit 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. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by a Note that verification of CCS Pump 1B-B to start on a Unit 2 SI signal is not required when substituted for CCS Pump C-S to establish OPERABILITY of CCS Train B for Unit 2. CCS Pump 1B-B does not receive an SI actuation signal from Unit 2. If it is operating and aligned as a substitute for CCS Pump C-S supplying the CCS Train B header, the presence of an SI signal in Unit 2 will have no effect on CCS Pump 1B-B and the pump will continue to perform its required safety function. In the event of a loss of offsite power, with or without an SI signal present, CCS Pump 1B-B will be automatically sequenced onto its respective diesel generator and continue to perform its required safety function.

SR 3.7.7.5

This SR assures the OPERABILITY of CCS Train B for Unit 2 when CCS Pump 1B-B is substituted for CCS Pump C-S. Since CCS Pump 1B-B does not receive an SI actuation signal from Unit 2, by verifying the pump is aligned and operating, assurance is provided that CCS Train B for Unit 2 will be OPERABLE in the event of a Unit 2 SI actuation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.7.5 (continued)

This SR is modified by a Note stating that it applies to the use of CCS Pump 1B-B when this pump is being used to support CCS Train B OPERABILITY for Unit 2.

REFERENCES

1. Watts Bar FSAR, Section 9.2.2, “Component Cooling System.”

2. Watts Bar Component Cooling System Description, N3-70-4002.

B 3.7 PLANT SYSTEMS

B 3.7.8 Essential Raw Cooling Water (ERCW) System

BASES

BACKGROUND

The ERCW provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the ERCW System also provides this function for various safety related and non-safety related components. The safety related function is covered by this LCO.

The shared ERCW system consists of eight 50% ERCW pumps, four traveling water screens, four screen wash pumps, four strainers, associated piping, valves, and instrumentation.

Water for the ERCW system enters two separate sump areas of the pumping station through four traveling water screens, two for each sump. Four ERCW pumping units, all on the same plant train, take suction from one of the sumps, and four more on the opposite plant train take suction from the other sump. One set of pumps and associated equipment is designated Train A, and the other Train B. These trains are redundant and are normally maintained separate and independent of each other. Each set of four pumps discharges into a common manifold, from which two separate headers (1A and 2A for Train A, and 1B and 2B for Train B) each with its own automatic backwashing strainer, supply water to the various system users. Two pumps per train are adequate to supply worst case conditions. Two pumps per train are aligned to receive power from different diesel generators. Operator designated pumps and valves are remote and manually aligned, except in the unlikely event of a loss-of-coolant accident (LOCA). The pumps are automatically started upon receipt of a safety injection (SI) signal, and some essential valves are aligned to their post-accident positions. Some manual realignments of motor-operated valves (MOVs) are necessary. The ERCW System also provides emergency makeup to the Component Cooling System (CCS) and is the backup water supply to the Auxiliary Feedwater System.

Additional information about the design and operation of the ERCW, along with a list of the components served, is presented in the FSAR, Section 9.2.1 (Ref. 1). The principal safety related function of the ERCW System is the removal of decay heat from the reactor via the CCS.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The design basis of the ERCW System is for one ERCW train, in conjunction with the CCS and a 100% capacity Containment Spray System and Residual Heat Removal (RHR), to remove core decay heat following a design basis LOCA as discussed in the FSAR, Section 9.2.1 (Ref. 1). This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System by the ECCS pumps. The ERCW System is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

The ERCW System, in conjunction with the CCS, also cools the unit from RHR, as discussed in the FSAR, Section 5.5.7, (Ref. 2) entry conditions to MODE 5 during normal and post accident operations. The time required for this evolution is a function of the number of CCS and RHR System trains that are operating. One ERCW train is sufficient to remove decay heat during subsequent operations in MODES 5 and 6. This assumes a maximum ERCW temperature of 85 °F occurring simultaneously with maximum heat loads on the system.

The ERCW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two ERCW trains are required to be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, assuming that the worst case single active failure occurs coincident with the loss of offsite power.

An ERCW train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. Two pumps, aligned to separate shutdown boards, are OPERABLE; and

b. The associated piping, valves, heat exchanger, and instrumentation and controls required to perform the safety related function are OPERABLE.

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, the ERCW System is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the ERCW System and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the ERCW System are determined by the systems it supports.

ACTIONS

A.1

If one ERCW train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE ERCW train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE ERCW train could result in loss of ERCW System function. Required Action A.1 is modified by two Notes. The first Note indicates that the applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources - Operating," should be entered if an inoperable ERCW train results in an inoperable diesel generator. The second Note indicates that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," should be entered if an inoperable ERCW train results in an inoperable decay heat removal train. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time period.

B.1 and B.2

If the ERCW train cannot be restored to OPERABLE status within the associated Completion Time, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 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.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR is modified by a Note indicating that the isolation of the ERCW flow to individual components may render those components inoperable, but does not affect the OPERABILITY of the ERCW System.

Verifying the correct alignment for manual, power operated, and automatic valves in the ERCW System flow path provides assurance that the proper flow paths exist for ERCW System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. 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 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.8.2

This SR verifies proper automatic operation of the ERCW System valves on an actual or simulated actuation signal. The ERCW System is a normally operating system that cannot be fully actuated as part of normal testing. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative control. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit 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. Therefore, the Frequency is acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.8.3

This SR verifies proper automatic operation of the ERCW pumps on an actual or simulated actuation signal. The ERCW System is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit 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. Therefore, the Frequency is acceptable from a reliability standpoint.

REFERENCES

1. Watts Bar FSAR, Section 9.2.1, "Essential Raw Cooling Water."
2. Watts Bar FSAR, Section 5.5.7, "Residual Heat Removal System."

B 3.7 PLANT SYSTEMS

B 3.7.9 Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The UHS provides a heat sink for processing and operating heat from safety related components during a transient or accident, as well as during normal operation. This is done by utilizing the Essential Raw Cooling Water (ERCW) System and the Component Cooling System (CCS).

The UHS is defined as the Tennessee River, including the TVA controlled dams upstream of the intake structure, Chickamauga Dam (the nearest downstream dam), and the plant intake channel, not including the intake structure, as discussed in FSAR Section 9.2.5 (Ref. 1). The maximum UHS temperature of 85°F ensures adequate heat load removal capacity for a minimum of 30 days after reactor shutdown or a shutdown following an accident, including a Loss of Coolant Accident (LOCA).

Additional information on the design and operation of the system, along with a list of components served, can be found in Reference 1.

APPLICABLE SAFETY ANALYSES

The UHS is the sink for heat removed from the reactor core following all accidents and anticipated operational occurrences in which the unit is cooled down and placed on residual heat removal (RHR) operation. Its maximum post accident heat load occurs approximately 20 minutes after a design basis loss of coolant accident (LOCA). Near this time, the unit switches from injection to recirculation and the containment cooling systems and RHR are required to remove the core decay heat.

The operating limits are based on conservative heat transfer analyses for the worst case LOCA. Reference 1 provides the details of the assumptions used in the analysis, which include worst expected meteorological conditions, conservative uncertainties when calculating decay heat, and worst case single active failure. The UHS is designed in accordance with Regulatory Guide 1.27 (Ref. 2), which requires a 30 day supply of cooling water in the UHS.

The UHS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The UHS is required to be OPERABLE and is considered OPERABLE if it contains water at or below the maximum temperature that would allow the ERCW System to operate for at least 30 days following the design basis LOCA without the loss of net positive suction head (NPSH), and without exceeding the maximum design temperature of the equipment served by the ERCW System. To meet this condition, the UHS temperature should not exceed 85°F.

APPLICABILITY

In MODES 1, 2, 3, and 4, the UHS is required to support the OPERABILITY of the equipment serviced by the UHS and required to be OPERABLE in these MODES.

In MODE 5 or 6, the OPERABILITY requirements of the UHS are determined by the systems it supports.

ACTIONS

A.1 and A.2

If the UHS is inoperable, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours and in MODE 5 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 3.7.9.1

This SR verifies that the ERCW System is available to cool the CCS to at least its maximum design temperature with the maximum accident or normal design heat loads for 30 days following a Design Basis Accident. The 24-hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES. This SR verifies that the average water temperature of the UHS is ≤ 85 °F (value does not account for instrument error).

BASES (continued)

REFERENCES

1. Watts Bar FSAR, Section 9.2.5, "Ultimate Heat Sink."

2. Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Power Plants," Revision 1, March 1974.

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Emergency Ventilation System (CREVS)

BASES

BACKGROUND

The CREVS provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke.

The CREVS consists of two independent, redundant trains that recirculate and filter the air in the control room envelope (CRE) and a CRE boundary that limits the inleakage of unfiltered air. Each CREVS train consists of a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and a fan. Ductwork, valves or dampers, doors, barriers, and instrumentation also form part of the system.

The CRE is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and may encompass other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

The CREVS is an emergency system, parts of which also operate during normal unit operations.

Actuation of the CREVS occurs automatically upon receipt of a safety injection signal in either unit or upon indication of high radiation in the outside air supply. Actuation of the system to the emergency mode of operation, closes the unfiltered outside air intake and unfiltered exhaust dampers, and aligns the system for recirculation of the air within the CRE through the redundant trains of air handling units, with a portion of the stream of air directed through HEPA and the charcoal filters. The

(continued)

BASES

BACKGROUND (continued)

emergency mode also initiates pressurization and filtered ventilation of the air supply to the CRE. Pressurization of the CRE prevents infiltration of unfiltered air from the surrounding areas of the building.

A single CREVS train operating at a flow rate of 4000 cubic feet per minute plus or minus 10 percent (includes less than or equal to 711 cubic feet per minute pressurization flow) will pressurize the CRE to a minimum 0.125 inches water gauge relative to external areas adjacent to the CRE boundary. The CREVS operation in maintaining the CRE habitable is discussed in the FSAR, Section 6.4 (Ref. 1).

Redundant supply and recirculation trains provide the required filtration should an excessive pressure drop develop across the other filter train. Normally open isolation dampers are arranged in series pairs so that the failure of one damper to shut will not result in a breach of isolation. A portion of the CREVS supply air ducting serving the main control room consists of round flexible ducting, triangular ducting constructed of duct board, and connecting metallic flow channels called air bars. These components are qualified to Seismic Category 1(L) requirements, which will ensure 1) the ducting will remain in place, 2) the physical configuration will be maintained such that flow will not be impeded, and 3) the ducting pressure boundary will not be lost during or subsequent to a SSE (Ref. 3). The remaining portions of CREVS are designed in accordance with Seismic Category I requirements (Ref. 4).

The CREVS is designed to maintain a habitable environment in the CRE for 30 days of continuous occupancy after a Design Basis Accident (DBA) without exceeding a 5 rem whole body dose or its equivalent to any part of the body.

APPLICABLE SAFETY ANALYSES

The CREVS components are arranged in redundant, safety related ventilation trains. The location of components and ducting within the CRE ensures an adequate supply of filtered air to all areas requiring access. The CREVS provides airborne radiological protection for the CRE occupants, as demonstrated by the CRE occupant dose analyses for the most limiting design basis loss of coolant accident, fission product release presented in the FSAR, Section 15.5.3 (Ref. 5).

The CREVS provides protection from smoke and hazardous chemicals to the CRE occupants. The analysis of hazardous chemical releases demonstrates that the toxicity limits are not exceeded in the CRE following a hazardous chemical release (Ref. 1 and 2). The evaluation of

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

a smoke challenge demonstrates that it will not result in the inability of the CRE occupants to control the reactor either from the control room or from the remote shutdown panels (Ref. 1 and 2).

The worst case single active failure of a component of the CREVS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function.

The CREVS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant CREVS trains are required to be OPERABLE to ensure that at least one is available if a single active failure disables the other train. Total system failure, such as from a loss of both ventilation trains or from an inoperable CRE boundary, could result in exceeding a dose of 5 rem whole body or its equivalent to any part of the body to the CRE occupants in the event of a large radioactive release.

Each CREVS train is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE. A CREVS train is OPERABLE when the associated:

a. Fan is OPERABLE;

b. HEPA filters and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions; and

c. Ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

In order for the CREVS trains to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is

(continued)

BASES

LCO (continued)

performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for CRE isolation is indicated.

APPLICABILITY

In MODES 1, 2, 3, 4, 5, and 6 and during movement of irradiated fuel assemblies, the CREVS must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA.

In MODES 5 and 6, the CREVS is required to cope with the release from the rupture of a waste gas decay tank.

During movement of irradiated fuel assemblies, the CREVS must be OPERABLE to cope with the release from a fuel handling accident.

ACTIONS

A.1

When one CREVS train is inoperable, for reasons other than an inoperable CRE boundary, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CREVS train is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE CREVS train could result in loss of CREVS function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

B.1, B.2 and B.3

If the unfiltered inleakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (allowed to be up to 5 rem whole body or its equivalent to any part of the body), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

(continued)

BASES

ACTIONS

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

During the period that the CRE boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional or unintentional. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period, and the use of mitigating actions. The 90 day Completion Time is reasonable based on the determination that the mitigating actions will ensure protection of CRE occupants within analyzed limits while limiting the probability that CRE occupants will have to implement protective measures that may adversely affect their ability to control the reactor and maintain it in a safe shutdown condition in the event of a DBA. In addition, the 90 day Completion Time is a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary.

C.1 and C.2

In MODE 1, 2, 3, or 4, if the inoperable CREVS train or the CRE boundary cannot be restored to OPERABLE status within the required Completion Time, the plant must be placed in a MODE that minimizes accident risk. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1 and D.2

In MODE 5 or 6, or during movement of irradiated fuel assemblies, if the inoperable CREVS train cannot be restored to OPERABLE status within the required Completion Time, action must be taken to immediately place the OPERABLE CREVS train in the emergency mode. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

An alternative to Required Action D.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

E.1

If both CREVS trains are inoperable in MODE 1, 2, 3, or 4, due to actions taken as a result of a tornado, the CREVS may not be capable of performing the intended function because of loss of pressurizing air to the control room. At least one train must be restored to OPERABLE status within 8 hours or the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The 8 hour restoration time is considered reasonable considering the low probability of occurrence of a design basis accident concurrent with a tornado warning.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

In MODE 5 or 6, or during movement of irradiated fuel assemblies with two CREVS trains inoperable or with one or more CREVS trains inoperable due to an inoperable CRE boundary, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the CRE. This places the unit in a condition that minimizes the accident risk. This does not preclude the movement of fuel to a safe position.

G.1

If both CREVS trains are inoperable in MODE 1, 2, 3, or 4, for reasons other than Condition B or Condition E the CREVS may not be capable of performing the intended function and the plant is in a condition outside the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not too severe, testing each train once every month provides an adequate check of this system. The systems need only be operated for ≥ 15 minutes to demonstrate the function of the system. The 31-day Frequency is based on the reliability of the equipment and the two train redundancy.

SR 3.7.10.2

This SR verifies that the required CREVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The CREVS filter tests are in accordance with Regulatory Guide 1.52 (Ref. 6). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.10.3

This SR verifies that each CREVS train starts and operates on an actual or simulated actuation signal. The Frequency of 18 months is based on industry operating experience and is consistent with the typical refueling cycle.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.10.4

This SR verifies the OPERABILITY of the CRE boundary by testing for unfiltered air inleakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem whole body or its equivalent to any part of the body and the CRE occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate, Condition B must be entered. Required Action B.3 allows time to restore the CRE boundary to OPERABLE status provided mitigating actions can ensure that the CRE remains within the licensing basis habitability limits for the occupants following an accident. Compensatory measures are discussed in Regulatory Guide 1.196, Section C.2.7.3 (Ref. 7), which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 8). These compensatory measures may also be used as mitigating actions as required by Required Action B.2. Temporary analytical methods may also be used as compensatory measures to restore OPERABILITY (Ref. 9). Options for restoring the CRE boundary to OPERABLE status include changing the licensing basis DBA consequence analysis, repairing the CRE boundary, or a combination of these actions. Depending upon the nature of the problem and the corrective action, a full scope inleakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

REFERENCES

1. Watts Bar FSAR, Section 6.4, "Habitability Systems."

2. Watts Bar FSAR, Section 9.4, "Air Conditioning, Heating, Cooling, and Ventilation Systems."

3. Watts Bar FSAR, Section 3.7.3.18, “Seismic Qualification of Main Control Room Suspended Ceiling and Air Delivery Components.”

4. NRC Safety Evaluation dated February 12, 2004, for License Amendment 50.

5. Watts Bar FSAR, Section 15.5.3, "Environmental Consequences of a Postulated Loss of Coolant Accident."

(continued)

BASES

REFERENCES (continued)

6. Regulatory Guide 1.52, Revision 2, "Design, Testing, and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmosphere Cleanup System Air Filtration and Adsorption Units of Light-Water Cooled Nuclear Power Plants."

7. Regulatory Guide 1.196, Revision 0, ”Control Room Habitability at Light-Water Nuclear Power Reactors.”

8. NEI 99-03, "Control Room Habitability Assessment," June 2001.

9. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, "NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability." (ADAMS Accession No. ML040300694).

B 3.7 PLANT SYSTEMS

B 3.7.11 Control Room Emergency Air Temperature Control System (CREATCS)

BASES

BACKGROUND

The CREATCS provides temperature control for the control room following isolation of the control room.

The CREATCS consists of two independent and redundant trains that provide cooling of recirculated control room air. Each train consists of an air handling unit (AHU), water chiller, chilled water pump, and associated piping, ductwork, instrumentation, and controls to provide for control room temperature control. The CREATCS is a subsystem providing air temperature control for the control room.

The CREATCS is an emergency system, parts of which also operate during normal unit operations. A single train will provide the required temperature control to maintain the control room between 60 °F and 104 °F. The CREATCS operation in maintaining the control room temperature is discussed in the FSAR, Section 9.4.1 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the CREATCS is to maintain the control room temperature for 30 days of continuous occupancy.

The CREATCS components are arranged in redundant, safety related trains. During emergency operation, the CREATCS maintains the temperature between 60 °F and 104 °F. A single active failure of a component of the CREATCS, with a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room temperature control. A portion of the CREATCS supply air ducting serving the main control room consists of round flexible ducting, triangular ducting constructed of duct board, and connecting metallic flow channels called air bars. These components are qualified to Seismic Category 1(L) requirements, which will ensure 1) the ducting will remain in place, 2) the physical configuration will be maintained such that flow will not be impeded, and 3) the ducting pressure boundary will not be lost during or subsequent to an SSE (Ref. 2). The remaining portions of CREATCS are designed in accordance with Seismic Category I requirements. The CREATCS is

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

capable of removing sensible and latent heat loads from the control room, which include consideration of equipment heat loads and personnel occupancy requirements, to ensure equipment OPERABILITY (Ref. 3).

The CREATCS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant trains of the CREATCS are required to be OPERABLE to ensure that at least one is available, assuming a single failure disabling the other train. Total system failure could result in the equipment operating temperature exceeding limits in the event of an accident.

The CREATCS is considered to be OPERABLE when the individual components necessary to maintain the control room temperature are OPERABLE in both trains. These components include the chillers, AHUs, and associated temperature control instrumentation. In addition, the CREATCS must be operable to the extent that air circulation can be maintained.

APPLICABILITY

In MODES 1, 2, 3, 4, 5, and 6, and during movement of irradiated fuel assemblies, the CREATCS must be OPERABLE to ensure that the control room temperature will not exceed equipment operational requirements following isolation of the control room.

In MODE 5 or 6, CREATCS is required during a control room isolation following a waste gas decay tank rupture.

ACTIONS

A.1

With one CREATCS train inoperable, action must be taken to restore OPERABLE status within 30 days. In this Condition, the remaining OPERABLE CREATCS train is adequate to maintain the control room temperature within limits. However, the overall reliability is reduced because a single failure in the OPERABLE CREATCS train could result in loss of CREATCS function. The 30 day Completion Time is based on the low probability of an event requiring control room isolation, the consideration that the remaining train can provide the required protection, and that alternate safety or non-safety related cooling means are available.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

In MODE 1, 2, 3, or 4, if the inoperable CREATCS train cannot be restored to OPERABLE status within the required Completion Time, the plant must be placed in a MODE that minimizes the risk. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

In MODE 5 or 6, or during movement of irradiated fuel, if the inoperable CREATCS train cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE CREATCS train must be placed in operation immediately. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that active failures will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

D.1

In MODE 5 or 6, or during movement of irradiated fuel assemblies, with two CREATCS trains inoperable, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk. This does not preclude the movement of fuel to a safe position.

E.1

If both CREATCS trains are inoperable in MODE 1, 2, 3, or 4, the CREATCS may not be capable of performing its intended function. Therefore, LCO 3.0.3 must be entered immediately.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR verifies that the heat removal capability of the system is sufficient to remove the heat load assumed in the sizing calculations in the control room. This SR consists of a combination of testing and calculations. This is accomplished by verifying that the system has not degraded. The only measurable parameters that could degrade undetected during normal operation are the system air flow and chilled water flow rate. Verification of these two flow rates will provide assurance that the heat removal capacity of the system is still adequate. The 18 month Frequency is appropriate since significant degradation of the CREATCS is slow and is not expected over this time period.

REFERENCES

1. Watts Bar FSAR, Section 9.4.1, “Control Room Area Ventilation System.”

2. Watts Bar FSAR, Section 3.7.3.18, “Seismic Qualification of Main Control Room Suspended Ceiling and Air Delivery Components.”

3. NRC Safety Evaluation dated February 12, 2004, for License Amendment 50.

B 3.7 PLANT SYSTEMS

B 3.7.12 Auxiliary Building Gas Treatment System (ABGTS)

BASES

BACKGROUND

The ABGTS filters airborne radioactive particulates from the area of active Unit 2 ECCS components and Unit 2 penetration rooms following a loss of coolant accident (LOCA).

The ABGTS consists of two independent and redundant trains. Each train consists of a heater, a prefilter, moisture separator, a high efficiency particulate air (HEPA) filter, two activated charcoal adsorber sections for removal of gaseous activity (principally iodines), and a fan. Ductwork, valves or dampers, and instrumentation also form part of the system. A second bank of HEPA filters follows the adsorber section to collect carbon fines and provide backup in case the main HEPA filter bank fails. The downstream HEPA filter is not credited in the analysis. The system initiates filtered ventilation of the Auxiliary Building Secondary Containment Enclosure (ABSCE) exhaust air following receipt of a Phase A containment isolation signal.

The ABGTS is a standby system, not used during normal plant operations. During emergency operations, the ABSCE dampers are realigned and ABGTS fans are started to begin filtration. Air is exhausted from the Unit 2 ECCS pump rooms, Unit 2 penetration rooms, and fuel handling area through the filter trains. The prefilters or moisture separators remove any large particles in the air, and any entrained water droplets present, to prevent excessive loading of the HEPA filters and charcoal adsorbers.

The ABGTS is discussed in the FSAR, Sections 6.5.1, 9.4.2, 15.0, and 6.2.3 (Refs. 1, 2, 3, and 4, respectively).

BASES (continued)

APPLICABLE SAFETY ANALYSES

The ABGTS design basis is established by the consequences of the limiting Design Basis Accident (DBA), which is a LOCA. The analysis of the LOCA assumes that radioactive materials leaked from the Emergency Core Cooling System (ECCS) are filtered and adsorbed by the ABGTS. The DBA analysis assumes that only one train of the ABGTS is functional due to a single failure that disables the other train. The accident analysis accounts for the reduction in airborne radioactive material provided by the one remaining train of this filtration system. The amount of fission products available for release from the ABSCE is determined for a LOCA. The assumptions and analysis for a LOCA follow the guidance provided in Regulatory Guide 1.4 (Ref. 5).

The ABGTS satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two independent and redundant trains of the ABGTS are required to be OPERABLE to ensure that at least one train is available, assuming a single failure that disables the other train, coincident with a loss of offsite power. Total system failure could result in the atmospheric release from the ABSCE exceeding the 10 CFR 100 (Ref. 6) limits in the event of a LOCA.

The ABGTS is considered OPERABLE when the individual components necessary to control exposure in the Auxiliary Building are OPERABLE in both trains. An ABGTS train is considered OPERABLE when its associated:

a. Fan is OPERABLE;

b. HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration function; and

c. Heater, moisture separator, ductwork, valves, and dampers are OPERABLE, and air circulation can be maintained.

APPLICABILITY

In MODE 1, 2, 3, or 4, the ABGTS is required to be OPERABLE to provide fission product removal associated with ECCS leaks due to a LOCA and leakage from containment and annulus.

In MODE 5 or 6, the ABGTS is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

BASES (continued)

ACTIONS

A.1

With one ABGTS train inoperable, action must be taken to restore OPERABLE status within 7 days. During this period, the remaining OPERABLE train is adequate to perform the ABGTS function. The 7-day Completion Time is based on the risk from an event occurring requiring the inoperable ABGTS train, and the remaining ABGTS train providing the required protection.

B.1 and B.2

When Required Action A.1 cannot be completed within the associated Completion Time, or when both ABGTS trains are inoperable, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in MODE 3 within 6 hours, and in MODE 5 within 36 hours. The Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

Standby systems should be checked periodically to ensure that they function properly. As the environmental and normal operating conditions on this system are not severe, testing each train once every month provides an adequate check on this system.

Monthly heater operation dries out any moisture accumulated in the charcoal from humidity in the ambient air. The system must be operated for ≥ 10 continuous hours with the heaters energized. The 31-day Frequency is based on the known reliability of the equipment and the two train redundancy available.

SR 3.7.12.2

This SR verifies that the required ABGTS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The ABGTS filter tests are in accordance with Regulatory Guide 1.52 (Ref. 7). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.12.3

This SR verifies that each ABGTS train starts and operates on an actual or simulated actuation signal. The 18-month Frequency is consistent with Reference 7.

SR 3.7.12.4

This SR verifies the integrity of the ABSCE. The ability of the ABSCE to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the ABGTS. During the post accident mode of operation, the ABGTS is designed to maintain a slight negative pressure in the ABSCE, to prevent unfiltered LEAKAGE. The ABGTS is designed to maintain a negative pressure between -0.25 inches water gauge and -0.5 inches water gauge (value does not account for instrument error) with respect to atmospheric pressure at a nominal flow rate ≥ 9300 cfm and ≤ 9900 cfm. The Frequency of 18 months is consistent with the guidance provided in NUREG-0800, Section 6.5.1 (Ref. 8).

An 18-month Frequency (on a STAGGERED TEST BASIS) is consistent with Reference 7.

REFERENCES

1. Watts Bar FSAR, Section 6.5.1, “Engineered Safety Feature (ESF) Filter Systems.”
2. Watts Bar FSAR, Section 9.4.2, “Fuel Handling Area Ventilation System.”
3. Watts Bar FSAR, Section 15.0, “Accident Analysis.”
4. Watts Bar FSAR, Section 6.2.3, “Secondary Containment Functional Design.”
5. Regulatory Guide 1.4, “Assumptions Used for Evaluating the Potential Radiological Consequences of a Loss of Coolant Accident for Pressurized Water Reactors.”
6. Title 10, Code of Federal Regulations, Part 100.11, “Determination of Exclusion Area, Low Population Zone, and Population Center Distance.”

(continued)

BASES

REFERENCES (continued)

7. Regulatory Guide 1.52 (Rev. 2), “Design, Testing and Maintenance Criteria for Post Accident Engineered-Safety-Feature Atmospheric Cleanup System Air Filtration and Adsorption Units of Light-Water Cooled Nuclear Power Plants.”

8. NUREG-0800, Section 6.5.1, “Standard Review Plan,” Rev. 2, “ESF Atmosphere Cleanup System,” July 1981.

B 3.7 PLANT SYSTEMS

B 3.7.13 Fuel Storage Pool Water Level

BASES

BACKGROUND

The minimum water level in the fuel storage pool meets the assumptions of iodine decontamination factors following a fuel handling accident. The specified water level shields and minimizes the general area dose when the storage racks are filled to their maximum capacity. The water also provides shielding during the movement of spent fuel.

A general description of the fuel storage pool design is given in the FSAR, Section 9.1.2 (Ref. 1). A description of the Spent Fuel Pool Cooling and Cleanup System is given in the FSAR, Section 9.1.3 (Ref. 2). The assumptions of the fuel handling accident are given in the FSAR, Section 15.5.6 (Ref. 3).

APPLICABLE SAFETY ANALYSES

The minimum water level in the fuel storage pool meets the assumptions of the fuel handling accident described in Regulatory Guide 1.183 (Ref. 4.) The Total Effective Dose Equivalent (TEDE) for control room occupants, individuals at the exclusion area boundary, and individuals within the low population zone will remain within 10 CFR 50.67 (Ref. 5) and Regulatory Position C.4.4 of Regulatory Guide 1.183 for a fuel handling accident.

According to Reference 3, there is 23 ft of water between the top of the damaged fuel bundle and the fuel pool surface during a fuel handling accident. With 23 ft of water, the assumptions of Reference 4 can be used directly. In practice, this LCO preserves this assumption for the bulk of the fuel in the storage racks. In the case of a single bundle dropped and lying horizontally on top of the spent fuel racks, however, there may be < 23 ft of water above the top of the fuel bundle and the surface, indicated by the width of the bundle.

The fuel storage pool water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The fuel storage pool water level is required to be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks. The specified water level preserves the assumptions of the fuel handling accident analysis (Ref. 3). As such, it is the minimum required for fuel storage and movement within the fuel storage pool.

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the fuel storage pool, since the potential for a release of fission products exists.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

When the initial conditions for prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the fuel storage pool water level is lower than the required level, the movement of irradiated fuel assemblies in the fuel storage pool is immediately suspended. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position.

If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

This SR verifies sufficient fuel storage pool water is available in the event of a fuel handling accident. The water level in the fuel storage pool must be checked periodically. The 7 day Frequency is appropriate because the volume in the pool is normally stable. Water level changes are controlled by plant procedures and are acceptable based on operating experience.

During refueling operations, the level in the fuel storage pool is in equilibrium with the refueling canal, and the level in the refueling canal is checked daily in accordance with SR 3.9.7.1.

BASES (continued)

REFERENCES

1. Watts Bar FSAR, Section 9.1.2, "Spent Fuel Storage."

2. Watts Bar FSAR, Section 9.1.3, "Spent Fuel Pool Cooling and Cleanup System."

3. Watts Bar FSAR, Section 15.5.6, "Fuel Handling Accident."

4. Regulatory Guide 1.183, “Alternate Source Terms for Evaluation Design Basis Accidents at Nuclear Power Reactors”, July 2000.

5. Title 10, Code of Federal Regulations, 10 CFR 50.67, “Accident Source Term.”

B 3.7 PLANT SYSTEMS

B 3.7.14 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from primary to secondary leakage in the steam generator. Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

The secondary coolant specific activity of 0.1 μCi/gm is used as input to the main steam line break accident analysis. The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives, (i.e., < 20 hours). I-131, with a half life of 8.04 days, concentrates faster than it decays, but does not reach equilibrium because of blowdown and other losses.

With the specified activity limit, the resultant 2 hour thyroid dose to a person at the exclusion area boundary (EAB) would be about 0.58 rem if the main steam safety valves (MSSVs) open for 2 hours following a trip from full power.

Operating a unit at the allowable limits could result in a 2 hour EAB exposure of a small fraction of the 10 CFR 100 (Ref. 1) limits, or the limits established as the NRC staff approved licensing basis.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break (MSLB), as discussed in the FSAR, Section 15.0 (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the radiological consequences of the postulated accident. The accident analysis, based on this and other assumptions, shows that the radiological consequences of an MSLB do not exceed a small fraction of the unit EAB limits (Ref. 1) for whole body and thyroid dose rates.

With the loss of offsite power, the remaining steam generators are available for core decay heat dissipation by venting steam to the atmosphere through the MSSVs and steam generator atmospheric dump valves (ADVs). The Auxiliary Feedwater System supplies the necessary makeup to the steam generators. Venting continues until the reactor coolant temperature and pressure have decreased sufficiently for the Residual Heat Removal System to complete the cooldown.

In the evaluation of the radiological consequences of this accident, the activity released from the steam generator connected to the failed steam line is assumed to be released directly to the environment. The unaffected steam generator is assumed to discharge steam and any entrained activity through the MSSVs and ADVs during the event. Since no credit is taken in the analysis for activity plateout or retention, the resultant radiological consequences represent a conservative estimate of the potential integrated dose due to the postulated steam line failure.

Secondary specific activity limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

As indicated in the Applicable Safety Analyses, the specific activity of the secondary coolant is required to be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131 to limit the radiological consequences of a Design Basis Accident (DBA) to a small fraction of the required limit (Ref. 1).

Monitoring the specific activity of the secondary coolant ensures that when secondary specific activity limits are exceeded, appropriate actions are taken in a timely manner to place the unit in an operational MODE that would minimize the radiological consequences of a DBA.

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, the limits on secondary specific activity apply due to the potential for secondary steam releases to the atmosphere.

In MODES 5 and 6, the steam generators are not being used for heat removal. Both the RCS and steam generators are depressurized, and primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.

ACTIONS

A.1 and A.2

DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant is an indication of a problem in the RCS and contributes to increased post accident doses. If the secondary specific activity is not within limits, the plant must be placed in a MODE in which the LCO does not apply. To achieve this status, the plant must be placed in at least MODE 3 within 6 hours, and in MODE 5 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 3.7.14.1

This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131, confirms the validity of the safety analysis assumptions as to the source terms in post accident releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE. The 31-day Frequency is based on the detection of increasing trends of the level of DOSE EQUIVALENT I-131, and allows for appropriate action to be taken to maintain levels below the LCO limit.

REFERENCES

1. 10 CFR 100.11, “Determination of Exclusion Area, Low Population Zone, and Population Center Distance.”

2. Watts Bar FSAR, Section 15.0, “Accident Analyses.”

B 3.7 PLANT SYSTEMS

B 3.7.15 Spent Fuel Assembly Storage

BASES

BACKGROUND

The spent fuel pool contains flux trap rack modules with 1386 storage positions that are designed to accommodate new fuel with a maximum enrichment of 4.95 ± 0.05 weight percent U-235 and fuel of various initial enrichments when stored in accordance with paragraph 4.3.1.1 in Section 4.3, Fuel Storage.

The water in the spent fuel storage pool normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 0.95 be evaluated in the absence of soluble boron. Hence, the design is based on the use of unborated water, which maintains the storage racks in a subcritical condition during normal operation with the racks fully loaded. The double contingency principle discussed and implemented in Reference 2, was based on the Proposed Revision 2 of Regulatory Guide 1.13, "Spent Fuel Storage Facility Design Basis," specifically Appendix A, "Nuclear Criticality Safety", section 1.4, which states; *At all locations in the LWR spent fuel storage facility where spent fuel is handled or stored, the nuclear criticality safety analysis should demonstrate that criticality could <u>not</u> occur without at least two unlikely, independent, and concurrent failures or operating limit violations*. ANSI N-16.1-1975, and the April 1978 NRC letter (Ref. 1) allows credit for soluble boron under other abnormal or accident conditions, since only a single accident need be considered at one time. For example, an abnormal scenario could be associated with the improper loading of a relatively high enrichment, low exposure fuel assembly. This could potentially increase the criticality of the storage racks. To mitigate these postulated criticality-related events, boron is dissolved in the pool water. Safe operation of the spent fuel storage design with no movement of assemblies may therefore be achieved by controlling the location of each assembly in accordance with the accompanying LCO. Prior to movement of an assembly in the pool, it is necessary to perform SR 3.9.9.1.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The hypothetical events can only take place during or as a result of the movement of an assembly. For these occurrences, the presence of soluble boron in the spent fuel storage pool, (controlled by LCO 3.9.9, "Spent Fuel Pool Boron Concentration") prevents criticality in the storage rack regions. By closely controlling the movement of each assembly and by checking the location of each assembly after movement, the time period for potential occurrences may be limited to a small fraction of the total operating time. During the remaining time period with no potential for such events, the operation may be under the auspices of the accompanying LCO.

The configuration of fuel assemblies in the fuel storage pool satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The restrictions on the placement of fuel assemblies within the spent fuel pool in accordance with Specification 4.3.1.1 in the accompanying LCO, ensures the k_{eff} will always remain $\leq$ 0.95, assuming the pool to be flooded with unborated water.

APPLICABILITY

This LCO applies whenever any fuel assembly is stored in the spent fuel storage pool.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

If unable to move irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If unable to move irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the action is independent of reactor operation. Therefore, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

When the configuration of fuel assemblies stored in the spent fuel storage pool is not in accordance with Specification 4.3.1.1, the immediate action is to initiate action to make the necessary fuel assembly movements to bring the configuration into compliance with Specification 4.3.1.1.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

This SR verifies by administrative means that the initial enrichment and burnup of the fuel assembly is in accordance with Specification 4.3.1.1 in the accompanying LCO.

REFERENCES

1. Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978, NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).

2. TVA, Document Number: PFE-R07, “Criticality Analysis Summary Report Watts Bar Nuclear Plant (WBN),” Revision 0, October 1996.

B 3.7 PLANT SYSTEMS

B 3.7.16 Component Cooling System (CCS) - Shutdown

BASES

BACKGROUND

The general description of the Component Cooling System (CCS) is provided in TS Bases 3.7.7, "Component Cooling System." The CCS has a Unit 2 Train A header supplied by CCS Pump 2A-A cooled through CCS Heat Exchanger (HX) A. Unit 1 has a separate Train A header containing HX B supplied by CCS Pump 1A-A. The Train B header is shared by Unit 1 and Unit 2 and contains HX C. Flow through the Train B header is normally supplied by CCS Pump C-S. CCS Pump 1B-B can be aligned to supply the Train B header, but it is normally aligned to the Unit 1 Train A header. Similarly, CSS Pump 2B-B can supply cooling water to the Train B header, but is normally aligned to the Unit 2 Train A header. The following describes the functions and requirements within the first 48 hours after shut down, when the Residual Heat Removal (RHR) System is being used for residual and decay heat removal.

During a normal shutdown, decay heat removal is via the reactor coolant system (RCS) loops until sometime after the unit has been cooled down to RHR entry conditions (T_{cold} < 350ºF). Therefore, as LCO 3.7.16 becomes Applicable (entry into Mode 4) the RCS loops are still OPERABLE. Entry into MODES 4 and 5 can place high heat loads onto the RHR System, CCS and the Essential Raw Cooling Water System (ERCW) when shutdown cooling is established. Residual and decay heat from the Reactor Coolant System (RCS) is transferred to CCS via the RHR HX. Heat from the CCS is transferred to the ERCW System via the CCS HXs. The CCS and ERCW systems are common between the two operating units.

During the first 48 hours after reactor shutdown, the heat loads are at sufficiently high levels that the normal pump requirement of LCO 3.7.7 for one CCS pump on the Train B header may not be sufficient to support shut down cooling of Unit 2, concurrent with either a nearly simultaneous shutdown of Unit 1 or a design basis loss of coolant accident (LOCA) on Unit 1, with loss of offsite power and a single failure of Train A power to 6.9 kV Shutdown Boards 1A-A and 2A-A.

In either scenario, CCS Pump C-S would normally be the only pump supplying the Train B header and the Train B header would be supplying both the Unit 1 RHR Train B HX and the Unit 2 RHR Train B HX. During the Unit 1 LOCA scenario, the Unit 1 RHR Train B HX would be cooling the recirculating Emergency Core Cooling System (ECCS) water from the containment sump.

(continued)

BASES

BACKGROUND (continued)

To assure that there would be adequate CCS flow to both units' RHR Train B HXs, prior to placing RHR in service for Unit 2, either CCS Pump 1B-B or 2B-B would be aligned to the CCS Train B header.

With two CCS pumps on the Train B header, CCS will supply at least 5000 gpm to the Unit 1 RHR Train B HX and 5000 gpm to the Unit 2 RHR Train B HX.

The alignment of either CCS Pump 1B-B or 2B-B to the CCS Train B header before entry into MODE 4 places both units in an alignment that supports LOCA heat removal requirements and allows the other unit to proceed to cold shutdown. Having the CCS pumps realigned while a unit being shut down with steam generators available for heat removal, precludes the need for manual action outside of the main control room to align CCS should a LOCA occur. If a LOCA occurs with the concurrent loss of the Train A 6.9 kV shutdown boards, CCS Pump 1B-B or 2B-B will be started from the main control room, if the pump is not already in operation. Both CCS pumps must be running before the RHR pump suction is transferred from the refueling water storage tank (RWST) to the containment sump to ensure adequate cooling is maintained. If a LOCA occurs, the C-S pump automatically starts on a safety injection (SI) actuation from either unit. The CCS pump control circuits are designed such that, if a pump is running and a loss of power occurs, the pump will be automatically reloaded on the DG. With this alignment, two CCS pumps will be available if a LOCA occurs on one unit when the other unit is being shut down.

Alternatively, the unit being shut down can remain on steam generator cooling for 48 hours before RHR is placed in service. If a LOCA occurred on the other unit, CCS would only be removing heat from one RHR HX. A single CCS pump and CCS HX provides the required heat removal capability.

After the unit has been shut down for greater than 48 hours, a single CCS pump on Train B provides adequate flow to both the Unit 1 and the Unit 2 RHR Train B HXs.

If the single failure were the loss of Train B power, the normal CCS alignment is acceptable, because CCS Pump 1A-A supplies the Unit 1 RHR Train A HX and CCS Pump 2A-A supplies the Unit 2 RHR Train A HX. CCS Pump 2A-A does not provide heat removal for Unit 1.

Additional information on the design and operation of the system, along with a list of the components served, is presented in the FSAR, Section 9.2.2 (Ref. 1). The principal safety related function of the CCS is the removal of heat from the reactor via the RHR System. This may be

(continued)

BASES

BACKGROUND (continued)

during a normal or post accident cool down and shut down. The Unit 1 CCS Train A header is not used to support Unit 2 operation.

APPLICABLE SAFETY ANALYSES

The CCS functions to cool the unit from RHR entry conditions in MODE 4 (T_{cold} < 350°F), to MODE 5 (T_{cold} < 200°F), during normal operations. The time required to cool from 350°F to 200°F is a function of the number of CCS and RHR trains operating. One CCS train is sufficient to remove heat during subsequent operations with T_{cold} < 200°F. This assumes a maximum ERCW inlet temperature of 85°F occurring simultaneously with the maximum heat loads on the system.

The design basis of the CCS is for one CCS train to remove the post LOCA heat load from the containment sump during the recirculation phase, with a maximum CCS HX outlet temperature of 110°F (Ref. 2). The ECCS LOCA analysis and containment LOCA analysis each model the maximum and minimum performance of the CCS, respectively. The normal maximum HX outlet temperature of the CCS is 95°F, and, during unit cooldown to MODE 5 (T_{cold} < 200°F), a maximum HX outlet temperature of 110°F is assumed. The CCS design based on these values, bounds the post accident conditions such that the sump fluid will not increase in temperature after alignment of the RHR HXs during the recirculation phase following a LOCA, and provides a gradual reduction in the temperature of this fluid as it is supplied to the RCS by the ECCS pumps.

The CCS is designed to perform its function with a single failure of any active component, assuming a loss of offsite power.

CCS - Shutdown satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The CCS trains are independent of each other to the degree that each has separate controls and power supplies and the operation of one does not depend on the other. During a unit shut down, one CCS train is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two trains of CCS must be OPERABLE. At least one CCS train will operate assuming the worst case single active failure occurs coincident with a loss of offsite power.

This LCO provides CCS train OPERABILITY requirements beyond the requirements of LCO 3.7.7 during the first 48 hours after reactor shut down, when the heat loads are at sufficiently high levels that the normal pump requirement of one CCS pump on the Train B header may not be sufficient to support shutdown cooling of Unit 2, concurrent with a nearly simultaneous shutdown of Unit 1 or a LOCA on Unit 1, a loss of offsite power, and single failure of Train A power to 6.9 kV Shutdown Boards 1A-A and 2A-A.

Because CCS Train B supports heat removal from Unit 1 and Unit 2, when Unit 2 has been shutdown ≤ 48 hours and the RHR System is relied on for heat removal, the following is required for CCS OPERABILITY:

a. Train A is OPERABLE when CCS Pump 2A-A is available and aligned to the CCS Train A header.

b. Train B is OPERABLE when two CCS pumps are available and aligned to the CCS Train B header using any combination of CCS Pumps 1B-B, 2B-B, and C-S.

c. The associated piping, valves, HXs, and instrumentation and controls required to perform the safety related function are OPERABLE.

Because Unit 2 is shutdown and on RHR cooling, no automatic actuations are required as a DBA on Unit 2, such as a LOCA, does not have to be mitigated.

APPLICABILITY

Prior to aligning the RHR System for RCS heat removal in MODE 4, an additional CCS pump must be powered from and aligned to the CCS Train B header to ensure adequate heat removal capability.

The Applicability is modified by a Note stating the LCO does not apply after the initial 48 hours after the unit enters MODE 3 from MODE 1 or MODE 2. Following extended operation in MODE 1, the heat loads are at sufficiently high levels that the normal pump requirement of LCO 3.7.7

(continued)

BASES

APPLICABILITY (continued)

for one CCS pump on the Train B header may not be sufficient to support shutdown cooling of Unit 2, concurrent with a near simultaneous shutdown of Unit 1 or a design basis LOCA on Unit 1, with loss of offsite power and a single failure of Train A power to 6.9 kV Shutdown Boards 1A-A and 2A-A. However, after the initial 48 hours following shutdown of the unit, the heat removal capability of both units is within the capabilities of the CCS without the need for an additional CCS pump aligned to the CCS Train B header.

ACTIONS

A.1

In MODE 4, if one CCS train is inoperable, and the unit is required to be placed in MODE 5 to comply with Required Actions, action must be taken to place the unit in MODE 5 within 24 hours. When the Required Actions of an LCO direct the unit to be placed in MODE 5, either a loss of safety function has occurred or the Required Action and Completion Time for restoring a safety-related component has not been met. Therefore, it is prudent to place the unit in a condition of lower energy with a lower potential for a postulated event. In this Condition, the remaining OPERABLE CCS train is adequate to perform the heat removal function. The 24 hour Completion Time is consistent with LCO 3.4.6, “RCS Loops - MODE 4,” Required Action B.1 for the Condition of one required RHR loop inoperable and no RCS loops OPERABLE.

B.1 and B.2

In MODE 4, if one CCS train is inoperable, and the unit is not required to be placed in MODE 5 to comply with Required Actions, actions are taken to verify LCO 3.4.6 is being met with two OPERABLE RCS loops with one loop in operation, and that the unit remains in MODE 4 (T_{avg} > 200ºF). These actions indicate the preference to maintain the unit in a condition with multiple methods of decay heat removal available, i.e., maintain the unit in MODE 4 with two RCS loops operable in addition to the remaining OPERABLE RHR loop. This action precludes entry into the LCO 3.4.6 Actions, as LCO 3.4.6 is met with two OPERABLE RCS loops and one RCS loop in operation. This Action is conservative to the Required Actions of LCO 3.4.6 when there are two OPERABLE RCS loops.

Maintaining the unit in MODE 4 with additional methods of decay heat removal available minimizes the likelihood of a situation where the decay heat and residual heat of the unit exceeds the capability of the available RHR loop resulting in the possibility of an unintentional MODE change. The Frequency of once per 12 hours ensures that the systems being relied on for heat removal are operating properly and are maintaining the unit in MODE 4. The 12 hour Frequency

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

is reasonable, considering the low probability of a change in system operation during this time period.

If the Required Actions and Completion Times of Condition B are not met, no actions are specified. Therefore, LCO 3.0.3 applies, requiring the unit to be placed in MODE 5 in 37 hours. With one CCS train inoperable and Required Actions require the unit to be placed in MODE 5, Condition A applies, requiring the unit to be placed in MODE 5 in 24 hours. This Action is consistent with the Required Actions of LCO 3.4.6 Condition B (no OPERABLE RCS loops and one inoperable RHR loop).

C.1

In MODE 4, if two CCS trains are inoperable, immediate action must be taken to restore one of the CCS trains to an OPERABLE status, as no CCS train is available to support the heat removal function. Required Action C.1 is consistent with LCO 3.4.6, “RCS Loops - MODE 4,” Required Action D.1 for the Condition of required RCS or RHR loops inoperable and no required RCS or RHR loop in operation.

Required Action C.1 is modified by two Notes. Note 1 indicates that all required MODE changes or power reductions are suspended until one CCS train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the plant into a less safe condition. Note 2 indicates that the applicable Conditions and Required Actions of LCO 3.4.6 be entered for RHR loops made inoperable by the inoperable CCS trains. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

D.1

Required Action D.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.7, “RCS Loops - MODE 5, Loops Filled,” be entered for RHR loops made inoperable by one or more inoperable CCS train(s). This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

In MODE 5, if one or more CCS train(s) is inoperable, action must be initiated immediately to restore the CCS train(s) to an OPERABLE status to restore heat removal paths. The immediate Completion Time reflects the importance of maintaining the capability of heat removal.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1

Verification that each required CCS pump that is not in operation is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain heat removal. Verification is performed by verifying proper breaker alignment and power available to the CCS pump(s). The 12 hour Frequency is based on engineering judgment.

SR 3.7.16.2

This SR verifies that two of the three CCS pumps that are powered from Train B are aligned to the Train B header. Verification of the correct physical alignment assures that adequate CCS flow can be provided to both the Unit 1 and Unit 2 RHR Train B HXs, if required. The 12 hour Frequency is based on engineering judgment, is consistent with procedural controls governing valve alignment, and ensures correct valve positions.

REFERENCES

1. Watts Bar FSAR, Section 9.2.2, “Component Cooling System.”

2. Watts Bar Component Cooling System Description, N3-70-4002.

B 3.7 PLANT SYSTEMS

B 3.7.17 Essential Raw Cooling Water (ERCW) System

BASES

BACKGROUND

The general description of ERCW is provided in TS Bases 3.7.8, "Essential Raw Cooling Water (ERCW) System." The descriptions of Applicable Safety Analyses, LCOs, Applicability, ACTIONS and Surveillance Requirements for applicable MODES are also described in TS Bases 3.7.8. The following discussion applies to the specific Applicability in TS 3.7.17 during the first 48 hours after shut down when the Residual Heat Removal (RHR) System is being used for residual and decay heat removal. The ERCW System provides a heat sink for the removal of process and operating heat from safety related components during a design basis accident (DBA) or transient. During normal operation, and a normal shutdown, the ERCW System also provides this function for various safety related and non-safety related components. The major post-accident heat load on the ERCW System is the Component Cooling System (CCS) heat exchangers (HXs), which are used to cool RHR and the containment spray HXs. The major heat load on the ERCW System when a unit is shut down on RHR is the CCS HX associated with the train(s) of RHR in service.

During a normal shutdown, decay heat removal is via the reactor coolant system (RCS) loops until sometime after the unit has been cooled down to RHR entry conditions (T_{cold} < 350ºF). Therefore, as LCO 3.7.17 becomes Applicable (entry into Mode 4) the RCS loops are still OPERABLE. After the RHR System is aligned as the principle method of decay heat removal, the heat loads on the ERCW System are increased. Normally, two ERCW pumps are sufficient to handle the cooling needs for maintaining one unit in normal operation while mitigating a DBA on the other unit. However, in the unlikely event of a loss of coolant accident (LOCA) on Unit 1 with a concurrent loss of offsite power and a single failure that results in the loss of both Train A or both Train B 6.9 kV shutdown boards while Unit 2 is on RHR shutdown cooling and has been shutdown for less than 48 hours, three ERCW pumps may be required.

This LCO controls the availability of ERCW pumps necessary to support mitigation of a LOCA on Unit 1 when Unit 2 has been shut down for ≤ 48 hours and is utilizing RHR for heat removal.

Additional information about the design and operation of the ERCW System, along with a list of the components served, is presented in the FSAR, Section 9.2.1 (Ref. 1).

BASES (continued)

APPLICABLE SAFETY ANALYSES

The design basis of the ERCW System is for one ERCW train, in conjunction with the CCS and a 100% capacity Containment Spray System and RHR, to remove core decay heat following a design basis LOCA as discussed in the FSAR, Section 9.2.1 (Ref. 1). This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System (RCS) by the Emergency Core Cooling System (ECCS) pumps. The ERCW System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power.

The ERCW System, in conjunction with the CCS, also cools the unit, as discussed in the FSAR, Section 5.5.7 (Ref. 2) from RHR entry conditions to MODE 5 during normal and post accident operations. The time required to enter MODE 5 is a function of the number of CCS and RHR System trains that are operating. One ERCW train is sufficient to remove heat during subsequent operations in MODES 5 and 6. This assumes a maximum ERCW inlet temperature of 85ºF occurring simultaneously with maximum heat loads on the system. In the first 48 hours after the shutdown of Unit 1 assuming a DBA LOCA on Unit 2 with the loss of offsite power and the concurrent loss of two 6.9 kV shutdown boards on the same power train as a single failure. Three ERCW pumps are required to provide the heat removal capacity assumed in the safety analysis for Unit 2 while continuing the cooldown of Unit 1.

ERCW - Shutdown satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO provides ERCW train OPERABILITY requirements beyond the requirements of LCO 3.7.8 during the first 48 hours after reactor shutdown, when the heat loads are at sufficiently high levels that the normal pump requirement of two ERCW pumps on one train may not be sufficient to support shutdown cooling of Unit 2, concurrent with a LOCA on Unit 1, an assumed loss of offsite power, and a single failure that affects both 6.9 kV shutdown boards in one power train.

Two ERCW trains are required to be OPERABLE to provide the required redundancy to ensure that the system functions to support a cooldown to MODE 5.

An ERCW train is considered OPERABLE during the first 48 hours after shutdown when:

a. Two pumps per train, aligned to separate shutdown boards, are OPERABLE; and

(continued)

BASES (continued)

LCO (continued)

b. One additional Train A pump and one additional Train B pump are capable of being aligned to their respective Unit 2 6.9 kV shutdown board (2A-A and 2B-B) and manually placed in service.

APPLICABILITY

Prior to aligning the RHR System for RCS heat removal in MODE 4, one additional ERCW pump must be capable of being powered by its respective Unit 2 6.9 kV shutdown board (2A-A and 2B-B) and manually placed in service to ensure adequate heat removal capability.

The Applicability is modified by a Note stating the LCO does not apply after the initial 48 hours after the unit enters MODE 3 from MODE 1 or MODE 2. Following extended operation in MODE 1, the heat loads are at sufficiently high levels that the normal pump requirement of LCO 3.7.8 for two ERCW pumps may not be sufficient to support shutdown cooling of Unit 2, concurrent with a design basis LOCA on Unit 1 with loss of offsite power and a single failure of Train A power to 6.9 kV Shutdown Boards 1A-A and 2A-A. However, after the initial 48 hours following shutdown of the unit, the heat removal capability of both units is within the capabilities of the ERCW System without the need for an additional ERCW pump in each train.

ACTIONS

A.1

In MODE 4, if one ERCW train is inoperable, and the unit is required to be placed in MODE 5 to comply with Required Actions, action must be taken to place the unit in MODE 5 within 24 hours. When the Required Actions of an LCO direct the unit to be placed in MODE 5, either a loss of safety function has occurred or the Required Action and Completion Time for restoring a safety-related component has not been met. Therefore, it is prudent to place the unit in a condition of lower energy with a lower potential for a postulated event. In this Condition, the remaining OPERABLE ERCW train is adequate to perform the heat removal function. The 24 hour Completion Time is consistent with LCO 3.4.6, “RCS Loops - MODE 4,” Required Action B.1 for the Condition of one required RHR loop inoperable and no RCS loops OPERABLE.

B.1 and B.2

In MODE 4, if one ERCW train is inoperable, and the unit is not required to be placed in MODE 5 to comply with Required Actions, actions are taken to verify LCO 3.4.6 is being met with two OPERABLE RCS loops with one loop in operation, and that the unit remains in MODE 4 (T_{avg} > 200ºF). These actions indicate the preference to maintain the unit

(continued)

BASES (continued)

ACTIONS

B.1 (continued)

in a condition with multiple methods of decay heat removal available, i.e., maintain the unit in MODE 4 with two RCS loops operable in addition to the remaining OPERABLE RHR loop. This action precludes entry into the LCO 3.4.6 Actions, as LCO 3.4.6 is met with two OPERABLE RCS loops and one RCS loop in operation. This Action is conservative to the Required Actions of LCO 3.4.6 when there are two OPERABLE RCS loops.

Maintaining the unit in MODE 4 with additional methods of decay heat removal available minimizes the likelihood of a situation where the decay heat and residual heat of the unit exceeds the capability of the available RHR loop resulting in the possibility of an unintentional MODE change. The Frequency of once per 12 hours ensures that the systems being relied on for heat removal are operating properly and are maintaining the unit in MODE 4. The 12 hour Frequency is reasonable, considering the low probability of a change in system operation during this time period.

If the Required Actions and Completion Times of Condition B are not met, no actions are specified. Therefore, LCO 3.0.3 applies, requiring the unit to be placed in MODE 5 in 37 hours. With one ERCW train inoperable and Required Actions require the unit to be placed in MODE 5, Condition A applies, requiring the unit to be placed in MODE 5 in 24 hours. This Action is consistent with the Required Actions of LCO 3.4.6 Condition B (no OPERABLE RCS loops and one inoperable RHR loop).

Although LCO 3.7.17 provides requirements in addition to those of LCO 3.7.8, the additional requirements of LCO 3.7.17 are not required for DG OPERABILITY. There is sufficient flow to the DGs from ERCW without a third ERCW in each train to support DG OPERABILITY. Although the requirement of LCO 3.7.17 may not be met (i.e., a third pump capable of being aligned to each ERCW Train) the requirement of LCO 3.7.8 is still met. If the requirement of LCO 3.7.8 is not met, the Actions of LCO 3.7.8 include the requirement to enter the Conditions and Required Actions of LCO 3.8.1 for DGs made inoperable by ERCW.

C.1

In MODE 4, if two ERCW trains are inoperable, immediate action must be taken to restore one of the ERCW trains to an OPERABLE status, as no ERCW train is available to support the heat removal function. Required Action C.1 is consistent with LCO 3.4.6, “RCS Loops - MODE 4,”

(continued)

BASES (continued)

ACTIONS

C.1 (continued)

Required Action D.1 for the Condition of required RCS or RHR loops inoperable and no RCS or RHR loop in operation.

Required Action C.1 is modified by two Notes. Note 1 indicates that all required MODE changes or power reductions are suspended until one ERCW train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the plant into a less safe condition. Note 2 indicates that the applicable Conditions and Required Actions of LCO 3.4.6 be entered for RHR loops made inoperable by the inoperable ERCW trains. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

D.1

Required Action D.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.7, “RCS Loops - MODE 5, Loops Filled,” be entered for RHR loops made inoperable by one or more inoperable ERCW train(s). This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

In MODE 5, if one or more ERCW train(s) is inoperable, action must be initiated immediately to restore the ERCW train(s) to an OPERABLE status to restore heat removal paths. The immediate Completion Time reflects the importance of maintaining the capability of heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.7.17.1

Verifying the availability of the ERCW pumps provides assurance that adequate ERCW flow is provided for heat removal. Verification that each required ERCW pump that is not in operation is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal. Verification is performed by verifying proper breaker alignment and power available to the ERCW pump(s). The ERCW pump Interlock Bypass Switches do not need to be in ‘Bypass’ in order to meet this SR. The associated ERCW pump Interlock Bypass Switch is positioned by procedure when the third ERCW pump in the respective train is required to be started. The 12 hour Frequency is based on engineering judgment.

REFERENCES

1. Watts Bar FSAR, Section 9.2.1, "Essential Raw Cooling Water."

2. Watts Bar FSAR, Section 5.5.7, "Residual Heat Removal System."

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

BASES

BACKGROUND

The plant AC Electrical Power Distribution System AC sources consist of the offsite power sources (preferred power sources, normal and alternate(s)), and the onsite standby power sources (Train A and Train B diesel generators (DGs)). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite Class 1E AC Distribution System supplies electrical power to four power trains, shared between the two units, with each train powered by an independent Class 1E 6.9 kV shutdown board. Power trains 1A and 2A comprise load group A, and power trains 1B and 2B comprise load group B. Two DGs associated with one load group can provide all safety related functions to mitigate a loss-of-coolant accident (LOCA) in one unit and safely shutdown the opposite unit. Each 6.9 kV shutdown board has two separate and independent offsite sources of power as well as a dedicated onsite DG source. The A and B train ESF systems each provide for the minimum safety functions necessary to shut down the plant and maintain it in a safe shutdown condition. Power can be supplied to each Class 1E 6.9 kV shutdown board from a normal offsite circuit (either CSST C or D), an alternate offsite circuit (either CSST C or D), a maintenance offsite circuit (either CSST A or B), or a DG.

Offsite power is supplied to the Watts Bar 161 kV transformer yard by two dedicated lines from the Watts Bar Hydro Plant switchyard. This is described in more detail in FSAR, Section 8 (Ref. 2). From the 161 kV transformer yard, two electrically and physically separated circuits provide AC power, through step-down common station service transformers, to the 6.9 kV shutdown boards. The two offsite AC electrical power sources are designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A detailed description of the offsite power network and the circuits to the Class 1E shutdown boards is found in Reference 2.

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network (i.e., Watts Bar Hydro Plant switchyard) to the onsite Class 1E ESF buses (i.e., 6.9 kV shutdown boards).

A single offsite circuit is capable of providing the ESF loads. Two of these circuits are required to meet the Limiting Condition for Operation.

(continued)

BASES

BACKGROUND (continued)

The onsite standby power source for each 6.9 kV shutdown board is a dedicated DG. WBN uses 4 DG sets for Unit 2 operation. These same DGs are shared for Unit 1 operation. A DG starts automatically on a safety injection (SI) signal (i.e., low pressurizer pressure or high containment pressure signals) or on a 6.9 kV shutdown board degraded voltage or loss-of-voltage signal (Refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation."). After the DG has started, it will automatically tie to its respective 6.9 kV shutdown board after offsite power is tripped as a consequence of 6.9 kV shutdown board loss-of-voltage or degraded voltage, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the 6.9 kV shutdown board on an SI signal alone. Following the trip of offsite power, a loss-of-voltage signal strips all nonpermanent loads from the 6.9 kV shutdown board. When the DG is tied to the 6.9 kV shutdown board, loads are then sequentially connected to its respective 6.9 kV shutdown board by the automatic sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

In the event of a loss of preferred power, the 6.9 kV shutdown boards are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a LOCA.

Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Within the required interval (FSAR Table 8.3-3) after the initiating signal is received, all automatic and permanently connected loads needed to recover the plant or maintain it in a safe condition are returned to service.

Ratings for Train 1A, 1B, 2A and 2B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 4400 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The ESF loads that are powered from the 6.9 kV shutdown boards are listed in Reference 2.

BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Section 6 (Ref. 4) and Section 15 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, "Power Distribution Limits;" Section 3.4, "Reactor Coolant System (RCS);" and Section 3.6, "Containment Systems."

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the Accident analyses and is based upon meeting the design basis of the plant. This results in maintaining at least two DGs associated with one load group or one offsite circuit OPERABLE during Accident conditions in the event of:

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

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Two qualified circuits between the Watts Bar Hydro 161 kV switchyard and the onsite Class 1E Electrical Power System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the plant.

Each offsite circuit must be capable of maintaining acceptable frequency and voltage, and accepting required loads during an accident, while connected to the 6.9 kV shutdown boards.

Offsite power from the Watts Bar Hydro 161 kV switchyard to the onsite Class 1E distribution system is from two independent immediate access circuits. Each of the two required circuits is routed from the switchyard through a 161 kV transmission line and four 161 kV to 6.9 kV transformers (common station service transformers) (CSSTs)) to the onsite Class 1E distribution system. Normally, the two required circuits are aligned to power the 6.9 kV shutdown boards through CSST C and CSST D. However, one of the two required circuits may also be aligned

(continued)

BASES

LCO (continued)

to power two shutdown boards in the same load group through either CSST A or CSST B and its associated Unit Boards, either directly from the CSST through the Unit Board or by automatic transfer from the Unit Station Service Transformer (USST) to the CSST. Use of CSST A or B as an offsite source requires that CSST A and B both be available and that the associated power and control feeders be in their normal positions to ensure independence. Due to independence limitations, CSST A and B cannot be credited for supply of both the offsite power sources simultaneously. The medium voltage power system starts at the low-side of the common station service transformers.

Each required offsite circuit is that combination of power sources described below that are either connected to the Class 1E AC Electrical Power Distribution System, or is available to be connected to the Class 1E AC Electrical Power Distribution System through automatic transfer at the 6.9 kV Shutdown or Unit Boards within a few seconds as required.

The following offsite power configurations meet the requirements of the LCO:

1. Normal Operation (i.e., all 6.9 kV shutdown boards aligned to their normal offsite circuit) – Two offsite circuits consisting of (a) AND (b) (no board transfers required; a loss of either circuit will not prevent the minimum safety functions from being performed);

   a. From the 161 kV Watts Bar Hydro Switchyard (Bay 13), through CSST D (winding Y) to 6.9 kV Shutdown Board 1A-A and (winding X) to 6.9kV Shutdown Board 2A-A: AND

   b. From the 161 kV Watts Bar Hydro Switchyard (Bay 4), through CSST D (winding X) to 6.9 kV Shutdown Board 1B-B and (winding Y) to 6.9 kV Shutdown Board 2B-B.

2. Alternate Operation (i.e., one or more 6.9 kV shutdown boards aligned to their alternate offsite circuit) – Two offsite circuits consisting of (a) AND (b) AND (c) (as needed) (Note: 6.9 kV shutdown board(s) aligned to normal circuit require an OPERABLE automatic transfer; a loss of either circuit will not prevent the minimum safety functions from being performed);

   a. From the 161 kV Watts Bar Hydro Switchyard (Bay 13), through CSST C (winding Y) to 6.9 kV Shutdown Board 1A-A (normal) AND/OR Shutdown Board 2B-B (alternate) and (winding X) to 6.9 kV Shutdown Board 2A-A (normal) AND/OR Shutdown Board 1B-B (alternate);

(continued)

LCO (continued)

b. From the 161 kV Watts Bar Hydro Switchyard (Bay 4), through CSST D (winding X) to 6.9 kV Shutdown Board 1B-B (normal) AND/OR Shutdown Board 2A-A (alternate) and (winding Y) to 6.9 kV Shutdown Board 2B-B (normal) AND/OR Shutdown Board 1A-A (alternate); AND

c. An OPERABLE transfer from the normal circuit to the alternate circuit for those 6.9 kV shutdown boards aligned to their normal circuit.

3. Unit Board Operation – Normal Supply (i.e., one offsite circuit includes a unit board supplied by its normal power supply, the USST) – Two offsite circuits consisting of (a) OR (b) (relies on automatic transfer of Unit Board power supply alignment from its normal supply (USST) to its alternate supply (CSST via Start Bus);

a. CSST C out -of-service;

1) From the 161 kV Watts Bar Hydro Switchyard (Bay 4), through CSST D (winding X) to 6.9 kV Shutdown Board 1B-B and (winding Y) to 6.9 kV Shutdown Board 2B-B;

2) From the 161 kV Watts Bar Hydro Switchyard (Bay 13), through CSST B (winding Y) to 6.9 kV Unit Board 1B and 6.9 kV Unit Board 2B (Breakers 1622 and 1632 open);

3) From Unit Board 1B to 6.9 kV Shutdown Board 1A-A (Breaker 1718 closed); AND

4) From Unit Board 2B to 6.9 kV Shutdown Board 2A-A (Breaker 1818 closed); AND

5) Unit Board 1B and Unit Board 2B normal to alternate automatic transfer circuit OPERABLE.

b. CSST D out -of-service;

1) From the 161 kV Watts Bar Hydro Switchyard (Bay 13), through CSST C (winding X) to 6.9 kV Shutdown Board 1A-A and (winding Y) to 6.9 kV Shutdown Board 2A-A;

(continued)

LOC
(continued)

2) From the 161 kV Watts Bar Hydro Switchyard (Bay 4), through CSST A (winding Y) to 6.9 kV Unit Board 1C and 6.9 kV Unit Board 2C (Breakers 1524 and 1534 open);

3) From 6.9 kV Unit Board 1C to 6.9 kV Shutdown Board 1B-B (Breaker 1726 closed); AND

4) From Unit Board 2C to 6.9 kV Shutdown Board 2B-B (Breaker 1826 closed); AND

5) Unit Board 1C and Unit Board 2C normal to alternate automatic transfer circuit OPERABLE.

4. Unit Board Operation – Alternate Supply (i.e., one offsite circuit includes a unit board supplied by its alternate power supply, the CSST via the Start Bus) – Two offsite circuits consisting of (a) OR (b) (no board transfers required);

a. CSST C out-of-service;

1) From the 161 kV Watts Bar Hydro Switchyard (Bay 4), through CSST D (winding X) to 6.9 kV Shutdown Board 1B-B and (winding Y) to 6.9 kV Shutdown Board 2B-B; AND

2) From the 161 kV Watts Bar Hydro Switchyard (Bay 13), through CSST B (winding Y) to 6.9 kV Unit Board 1B and 6.9 kV Unit Board 2B (Breakers 1622 and 1632 closed) to 6.9 kV Shutdown Board 1A-A and 6.9 kV Shutdown Board 2A-A (Breakers 1718 and 1818 closed), respectively.

b. CSST D out-of-service;

1) From the 161 kV Watts Bar Hydro Switchyard (Bay 13), through CSST C (winding X) to 6.9 kV Shutdown Board 1A-A and (winding Y) to 6.9 kV Shutdown Board 2A-A; AND

2) From the 161 kV Watts Bar Hydro Switchyard (Bay 4), through CSST A (winding Y) to 6.9 kV Unit Board 1C and 6.9 kV Unit Board 2C (Breakers 1524 and 1534 closed) to 6.9 kV Shutdown Board 1B-B and 6.9 kV Shutdown Board 2B-B (Breakers 1726 and 1826 closed), respectively.

Note: When using either CSST A or B as a qualified offsite circuit, the CSST (A or B) not in use as a qualified circuit must be available.

(continued)

BASES

LCO (continued)

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective 6.9 kV shutdown board on detection of loss-of-voltage. This will be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the 6.9 kV shutdown boards. 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 accident signal while operating in parallel test mode.

Proper sequencing of loads, including tripping of non-essential loads, is a required function for DG OPERABILITY.

The AC sources in one train must be separate and independent (to the extent possible) of the AC sources in the other train. For the DGs, separation and independence are complete. However, CSST A or B can only supply two 6.9 kV shutdown boards in the same load group to ensure the separation criteria is met.

For the offsite AC sources, separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus, with fast transfer capability to the other circuit OPERABLE, and not violate separation criteria. A circuit that is not connected to an ESF bus is required to have OPERABLE fast transfer interlock mechanisms to at least two ESF buses to support OPERABILITY of that circuit.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, 3, and 4 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.

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, “AC Sources - Shutdown.”

BASES (continued)

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

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

A.2

Required Action A.2, which only applies if the train cannot be powered from a required offsite source, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of safety function of critical redundant required features. These features are powered from the redundant AC electrical power trains. This includes motor driven auxiliary feedwater pump. Single train systems, such as the turbine driven auxiliary feedwater pump, may not be included.

The Completion Time for Required Action A.2 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. The train has no offsite power supplying its loads; and

b. A required feature on the other train is inoperable.

If at any time during the existence of Condition A (one offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

(continued)

BASES

ACTIONS

A.2 (continued)

Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. Twenty four hours is acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to Train A and Train B of the onsite Class 1E Distribution System. The 24 hour Completion Time takes into account the component 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. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one required 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 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 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 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

(continued)

BASES

ACTIONS

A.3 (continued)

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.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

B.1

To ensure a highly reliable power source remains with one or more DGs inoperable in Train A OR with one or more DGs inoperable in Train B, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon required offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. This includes motor driven auxiliary feedwater pumps. Single train systems, such as the turbine driven auxiliary feedwater pump, are not included. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has inoperable DG(s).

The Completion Time for Required Action B.2 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. An inoperable DG exists; and

b. A required feature on the other train (Train A or Train B) is inoperable.

(continued)

BASES

ACTIONS

B.2 (continued)

If at any time during the existence of this Condition (one or more DGs inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one or more required DGs in Train A or one or more DGs in Train B inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DGs, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is Acceptable because it minimizes risk while allowing time for restoration before subjecting the plant to transients associated with shutdown.

In this Condition, 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 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, a reasonable time for repairs, and the 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 DG(s). If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. For the performance of a Surveillance, Required Action B.3.1 is considered satisfied since the cause of the DG being inoperable is apparent. If the cause of inoperability exists on other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered if the other inoperable DGs are not on the same train. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 and B.3.2 are 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 that DG(s).

(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 corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

B.4

According to Regulatory Guide 1.93, (Ref. 6), 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 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 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 could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the DGs. At this time, an offsite circuit could again become inoperable, the DGs 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 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.

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

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Required Action C.1, which applies when two required offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains 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 powered from redundant AC safety trains. This includes motor driven auxiliary feedwater pumps. Single train features, such as the turbine driven auxiliary pump, are not included in the list.

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. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable (e.g., combinations that involve an offsite circuit and one DG inoperable, or one or more DGs in each train inoperable). However, two factors tend to decrease the severity of this level of degradation:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable required offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the plant in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Reference 6, with the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any train, the Conditions and Required Actions for LCO 3.8.9, “Distribution Systems - Operating,” must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one or more DGs in a train, without regard to whether a train is de-energized. LCO 3.8.9 provides the appropriate restrictions for a de-energized train.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours.

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 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.

E.1 and E.2

With one or more required DGs in Train A inoperable simultaneous with one or more required DGs in Train B inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for 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 Reference 6, with one or more required DGs in Train A inoperable simultaneous with one or more required DGs in Train B inoperable, operation may continue for a period that should not exceed 2 hours.

F.1 and F.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

G.1 and H.1

Condition G and Condition H correspond to a level of degradation in which all redundancy in the AC electrical power supplies cannot be guaranteed. 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 plant 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, Appendix A, GDC 18 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are in accordance with the recommendations of Regulatory Guide 1.9 (Ref. 3) and Regulatory Guide 1.137 (Ref. 9), as addressed in the FSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. 6800 volts is the minimum steady state output voltage and the 10 seconds transient value. 6800 volts is 98.6% of the nominal bus voltage of 6900 V corrected for instrument error and is the upper limit of the minimum voltage required for the DG supply breaker to close on the 6.9 kV shutdown board. The specified maximum steady state output voltage of 7260 V is 110% of the nameplate rating of the 6600 V motors. The specified 3 second transient value of 6555 V is 95% of the nominal bus voltage of 6900 V. The specified maximum transient value of 8880 V is the maximum equipment withstand value provided by the DG manufacturer. The specified minimum and maximum transient frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. The steady state minimum and maximum frequency values are 59.8 Hz and 60.1 Hz. These values ensure that the safety related plant equipment powered from the DGs is capable of performing its safety functions.

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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 to maintain the plant in a safe shutdown condition.

For the purposes of SR 3.8.1.2 and SR 3.8.1.7 testing, the DGs are started from standby conditions. The DG engines for WBN have an oil circulation and soakback system that operates continuously to preclude the need for a prelube and warmup when a DG is started from standby. 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 manufacturer recommends a modified start in which the starting speed of DGs is limited, warmup is limited to this lower speed, and the DGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 2, which is only applicable when such modified start procedures are recommended by the manufacturer.

SR 3.8.1.7 requires that, at a 184 day Frequency, the DG starts from an actual or simulated loss of offsite power signal and achieves required voltage and frequency within 10 seconds. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the FSAR, Section 15 (Ref. 5). Starting the DG from an emergency start signal ensures the automatic start relays are cycled (de-energized) on a 184 day Frequency.

The 10 second start requirement is not applicable to SR 3.8.1.2 (See Note 2.) when a modified start procedure as described above is used. During this testing, the diesel is not in an accident mode and the frequency is controlled by the operator instead of the governor's accident speed reference. If a modified start is not used, the 10 second start requirement of SR 3.8.1.7 applies. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not dampened out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, WBN will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

Since SR 3.8.1.7 requires 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 is the intent of Note 1 of SR 3.8.1.2.
The normal 31 day Frequency for SR 3.8.1.2 (See Table 3.8.1-1, "Diesel Generator Test Schedule," in the accompanying LCO.) 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 verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads greater than or equal to the 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 between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while the 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.

The 31 day Frequency for this Surveillance (Table 3.8.1-1) is consistent with Regulatory Guide 1.9 (Ref. 3).

This SR is modified by four Notes. Note 1 indicates 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 states that momentary transients, because of changing bus loads, do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.4

This SR provides verification that the level of fuel oil in each DG skid-mounted day tank is at or above the level (≥ 218.5 gallons, value does not account for instrument error) 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 skid-mounted day tanks once every 31 days eliminates the necessary environment for bacterial survival.

This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 9). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated skid-mounted day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.1.6 (continued)

The 31 day Frequency corresponds to the DG testing frequency since the design of fuel transfer systems is such that the pumps operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the skid-mounted day tanks during or following DG testing.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Transfer of each 6.9 kV shutdown board power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 18 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for the first 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. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

1.) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2.) Post-corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

Note 2 specifies that the transfer capability is only required to be met when one or more 6.9 kV shutdown boards require normal and alternate power supplies. When all the 6.9 kV shutdown boards are supplied power by their normal power supply, the alternate supply is not required. When one or more of the 6.9 kV shutdown boards are supplied power from their alternate power supply, the automatic transfer for those 6.9 kV shutdown boards required to transfer from their normal to alternate power supply is required to be OPERABLE. If one or more of the 6.9 kV shutdown boards are aligned to its alternate source (CSST C or CSST D), this SR verifies that at least two 6.9 kV shutdown boards in the same load group will be powered from an offsite circuit if a fault occurs on either circuit.

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 largest single load for each DG is the essential raw cooling water pump at 800 HP. This Surveillance may be accomplished by: 1) 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 2) tripping its associated single largest post accident load with the DG solely supplying the bus. As required by Regulatory Guide 1.9, C1.4 (Ref. 3), the load rejection test is acceptable if the increase in diesel speed does not exceed 75% of the difference between synchronous speed and the overspeed trip setpoint, or 15% above synchronous speed, whichever is lower.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

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 a typical 5 second load sequence interval associated with sequencing of the 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 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3).

This SR is 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. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post-corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

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 ≥ 0.8 and ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

.

(continued)

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 for 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 using a power factor $\geq$ 0.8 and $\leq$ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

The 18 month Frequency is consistent with the recommendation of Regulatory Guide 1.9 (Ref. 3) 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 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. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post-corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.11

As required by Regulatory Guide 1.9 (Ref. 3), paragraph C2.2.4, 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 non-essential 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.

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 is 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, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or residual heat removal (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 connection and loading of loads, testing that adequately shows the capability of the DG systems 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 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), Table 1, takes into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The DG engines for WBN have an oil circulation and soakback system that operates continuously to preclude the need for a prelube and warmup when a DG is started from standby.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

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. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post-corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.1.12

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 minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not dampened out by load application. This period may extend beyond the 10 seconds acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, WBN will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. 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 ESF signal without loss of offsite power.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

The requirement to verify the connection 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, or 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 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 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.

For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The DG engines for WBN have an oil circulation and soakback system that operates continuously to preclude the need for a prelube and warmup when a DG is started from standby.

This SR is modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this Surveillance 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. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post-corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

This Surveillance demonstrates that DG non-critical protective functions (e.g., high jacket water temperature) are bypassed on an automatic or emergency start signal and that critical protective functions (engine overspeed and generator differential current) remain functional to affect a DG trip to avert substantial damage to the DG unit or to the safety related equipment powered by the DG. It is not necessary to actually trip the DG using critical protective functions in order to satisfy this SR. The non-critical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 18 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. 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.

The SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required DG from service. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post-corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), paragraph C2.2.9, requires demonstration once per 18 months that the DGs can start and run continuously for an interval of not less than 24 hours, ≥ 2 hours of which is at a load between 105% and 110% of the continuous duty rating and the remainder of the time at a load equivalent to 90% to 100% 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 prelubricating 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 using a power factor of ≥ 0.8 and ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience. 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.

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the power factor limit will not invalidate the test. Note 2 establishes that this SR may be performed on only one DG at a time while in MODE 1, 2, 3, or 4. This is necessary to ensure the proper response to an operational transient (i.e., loss of offsite power, ESF actuation). Therefore, three DGs must be maintained operable and in a standby condition during performance of this test. In this configuration, the plant will remain within its design basis, since at all times safe shutdown can be achieved with two DGs in the same train.

Note 3 establishes that credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post-corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

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 seconds. The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not dampened out by load application. This period may extend beyond the 10 seconds acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, WBN will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. The 10 seconds time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), Table 1.

The DG engines for WBN have an oil circulation and soakback system that operates continuously to preclude the need for a prelube and warmup when a DG is started from standby.

This SR is modified by a Note to ensure that the test is performed with the diesel sufficiently hot. 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. 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. Momentary transients due to changing bus loads do not invalidate this test.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.16

As required by Regulatory Guide 1.9 (Ref. 3), paragraph C2.2.11, this Surveillance ensures that the manual synchronization and automatic load transfer from the DG to the offsite source can be made and 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 autoclose signal on bus undervoltage, and the load sequence timers are reset.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), Table 1, and takes into consideration plant conditions required to perform the Surveillance.

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. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post-corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.17

Demonstration of the test mode override ensures that the DG availability under accident conditions will not be compromised as the result of testing and the DG will automatically reset to ready-to-load operation if a LOCA actuation 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. 10), 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 was 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 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), Table 1, 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 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. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post-corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

Under accident and loss of offsite power conditions loads are sequentially connected to the 6.9 kV shutdown board by the automatic load sequencer. 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 load sequence time specified in FSAR Table 8.3-3 ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load block and that safety analysis assumptions regarding ESF equipment time delays are not violated. The allowable values for the time delay relays are contained in system specific setpoint scaling documents. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), Table 1, 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 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. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post-corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(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 ESF actuation 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 months 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.

For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The DG engines for WBN have an oil circulation and soakback system that operates continuously to preclude the need for a prelube and warmup when a DG is started from standby.

This SR is modified by a Note. The reason for the Note is that the performance of 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. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post-corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.20

This SR verifies that DG availability is not compromised by the idle start circuitry, when in the idle mode of operation, and that an automatic or emergency start signal will disable the idle start circuitry and command the engine to go to full speed. The 18 month frequency is consistent with the expected fuel cycle lengths and is considered sufficient to detect any degradation of the idle start circuitry.

SR 3.8.1.21

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 minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not dampened out by load application. This period may extend beyond the 10 seconds acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, WBN will monitor and trend the actual time to reach steady state operation as a means of ensuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), Table 1.

For the purpose of this testing, the DGs shall be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The DG engines for WBN have an oil circulation and soakback system that operates continuously to preclude the need for a prelube and warmup when a DG is started from standby.

SR 3.8.1.22

Transfer of the 6.9 kV Unit Boards 1B, 1C, 2B, and 2C power supply from the normal supply (USST) to the alternate power supply (CSST via the 6.9 kV Start bus) demonstrates the OPERABILITY of the maintenance offsite circuit to power the shutdown loads when the shutdown board is powered from the USST. The 18-month Frequency of 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 at the

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

18-month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for the first Note is that during operation with the reactor critical, performance of this SR for the 1B or 1C Unit Board could cause perturbations to the electrical distribution systems that could challenge continued steady state operation, and as a result, plant safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

Note 2 specifies that transfer capability is only required to be met for 6.9 kV Unit Boards that require normal and alternate power supplies. If the unit board is not a part of the required qualified circuit or the qualified circuit is powered from the CSST through the unit board to the 6.9 kV shutdown board, the automatic transfer is not required.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 > 0.975 per demand.

According to Regulatory Guide 1.9, Revision 3 (Ref. 3), each DG 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 will allow for 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 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 7 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 the 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.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion (GDC) 17, “Electrical Power Systems.”

2. Watts Bar FSAR, Section 8.2, “Offsite Power System,” and Tables 8.3-1 to 8.3-3, “Safety-Related Standby (Onsite) Power Sources and Distribution Boards,” “Shutdown Board Loads Automatically Tripped Following a Loss of Nuclear Unit and Preferred (Offsite) Power,” and “Diesel Generator Load Sequentially Applied Following a Loss of Nuclear Unit and Preferred (Offsite) Power.”

(continued)

BASES

REFERENCES (continued)

3. Regulatory Guide 1.9, Rev. 3, “Selection, Design, Qualification and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants,” July 1993.

4. Watts Bar FSAR Section 6, “Engineered Safety Features.”

5. Watts Bar FSAR, Section 15.4, “Condition IV-Limiting Faults.”

6. Regulatory Guide 1.93, Rev. 0, “Availability of Electric Power Sources,” December 1974.

7. Generic Letter 84-15, “Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability,” July 2, 1984.

8. Title 10, Code of Federal Regulations, Part 50, Appendix A, GDC 18, “Inspection and Testing of Electric Power Systems.”

9. Regulatory Guide 1.137, Rev. 1, “Fuel Oil Systems for Standby Diesel Generators,” October 1979.

10. IEEE-308-1971, “IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations,” Institute of Electrical and Electronic Engineers.

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 5 and 6 and during movement of irradiated fuel assemblies ensures that:

a. The plant 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 plant status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In general, when the plant is shut down, the Technical Specifications requirements ensure that the plant has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and of 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, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required 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 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

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

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in 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, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability to support 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 10 CFR 50.36(c)(2)(ii).

LCO

One offsite circuit capable of supplying the onsite Class 1E power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems - Shutdown," ensures that all required loads are powered from offsite power. Two OPERABLE DGs (1A-A and 2A-A, or 1B-B and 2B-B), associated with a distribution system train required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and the two DGs 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).

(continued)

BASES

LCO (continued)

The qualified offsite circuit must be capable of maintaining acceptable frequency and voltage, and accepting required loads during an accident, while connected to the Engineered Safety Feature (ESF) bus(es). Qualified offsite circuits are those that are described in the FSAR and are part of the licensing basis for the plant.

Offsite power from the Watts Bar Hydro 161 kV switchyard to the onsite Class 1E distribution system is from two independent immediate access circuits. Each of the two circuits is routed from the switchyard through a 161 kV transmission line and 161 kV to 6.9 kV transformer (common station service transformers) to the onsite Class 1E distribution system. The medium voltage power system starts at the low-side of the common station service transformers.

The DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective 6.9 kV shutdown board on detection of bus loss-of-voltage. This sequence must be accomplished within 10 seconds. The DG must be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the 6.9 kV shutdown board. 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 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 accident signal while operating in parallel test mode).

Proper sequencing of loads, including tripping of non-essential loads, is a required function for DG OPERABILITY.

It is acceptable for trains to be cross tied during shutdown conditions, allowing a single offsite power circuit to supply all required trains.

BASES (continued)

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

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

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

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

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1.

ACTIONS

A.1

An offsite circuit would be considered inoperable if it were not available to one required ESF train. Although two trains are required by LCO 3.8.10, the one train with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By the allowance of the option to declare required features inoperable, with no offsite power available, appropriate restrictions will be implemented in accordance with the affected required features LCO's ACTIONS.

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 trains, the option would still exist to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With either 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, and operations involving positive reactivity additions. The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SDM is maintained.

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

BASES (continued)

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's ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no AC power to any 6.9 kV shutdown board, the 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 train is de-energized. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a de-energized train.

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, 3, and 4. 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 3.8.1.21 is excepted because starting independence is not required with the DG(s) that is not required to be operable.

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 performance of SRs, and to preclude de-energizing a required 6.9 kV bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

1. Watts Bar FSAR, Section 8.0, "Electric Power."

2. Title 10, Code of Federal Regulations, Part 50, General Design Criterion 17, "Electric Power Systems."

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 four interconnected storage tanks embedded in the building foundation having a fuel oil capacity sufficient to operate that diesel for a period of 7 days while the DG is supplying maximum post loss of coolant accident load demand discussed in the FSAR, Section 8.3 (Ref. 1). The maximum load demand is calculated using the assumption that a minimum of any two DGs is available. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

An approximately 550-gal skid-mounted day tank is provided for each diesel engine. Each DG incorporates two diesel engines operating in tandem and directly coupled to the generator. Each skid-mounted day tank has fuel capacity for approximately 2 hours of full-load operations (Ref. 1). Fuel oil is transferred from 7 day storage tanks to the skid-mounted day tank by a pump located on each skid-mounted day 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 diesel engine. In the event that the piping between the last isolation valve and the skid-mounted day tank breaks, the use of one DG can be lost. This occurs only after the two hour supply of fuel in the skid-mounted day tank has been used.

During operation of the DGs, fuel oil pumps driven by the diesel engines transfer fuel from the skid-mounted day tanks to the skid-mounted diesel engine fuel manifolds. Level controls mounted on the skid-mounted day tanks automatically start and stop the 7 day storage tank transfer pumps.

In addition, alarms both locally and in the control room annunciate low level and high level in any skid-mounted day tank.

In the unlikely event of a failure in one of the supply trains, the associated skid-mounted day tank low-level alarm annunciates when the fuel oil remaining in the tank provides approximately 1 hour of full-load operation, thus allowing the operator to take corrective action to prevent the loss of the diesel.

(continued)

BASES

BACKGROUND (continued)

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 appearance, the kinematic viscosity, specific gravity (or API gravity), impurity level and flash point.

Each of the engines in the tandem generator sets is provided with its own lube oil system, which is an integral part of each of the DG units. The piping and components for the skid-mounted lubrication system are vendor supplied, safety-related, ANSI B31.1, Seismic Category I. The diesel engine lubrication system for each diesel engine is a combination of four subsystems (Ref. 4): the main lubricating subsystem, the piston cooling subsystem, the scavenging oil subsystem, and the motor-driven circulating pump and soak back pump system. The main lubricating subsystem supplies oil under pressure to the various moving parts of the diesel engine. The piston cooling subsystem supplies oil for piston cooling and lubrication of the piston pin bearing surfaces. The soak-back subsystem has a two-fold purpose: prelubes the turbocharger bearing area in support of a start signal and removes residual heat from the bearing area upon engine shutdown. The scavenging oil subsystem supplies the other systems with cooled and filtered oil. Oil is drawn from the engine sump by the scavenging pump through a strainer in the strainer housing located on the front side of the engine. From the strainer the oil is pumped through oil filters and a cooler. The filters are located on the accessory racks of the engines. The oil is cooled in the lube oil cooler by the closed circuit cooling water system in order to maintain proper oil temperature during engine operation.

Each engine lube oil system contains approximately 331 gal of lube oil, ample for at least 7 days of DG unit full load operation without requiring replenishment. The established oil consumption rate is 0.83 gal per hour. An additional standby oil reserve is stored onsite to replenish the engines for longer periods of operation and after their periodic test operations. The inventory of lube oil in each engine is determined by reading the lube oil sump dipstick while the engine is at "Hot Idle." The quantity of oil (gallons) at each mark on the dipstick is as follows:

MARK	IN SYSTEM	IN SUMP	USABLE
"FULL"	331	251	184
"7" DAY	287	207	140
"6" DAY	267	187	120
"LOW"	147	67	ZERO

(continued)

BASES

BACKGROUND (continued)

Each DG has an air start system with adequate capacity for five successive start attempts on the DG without recharging the air start receiver(s).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Section 6 (Ref. 5), and in the FSAR, Section 15 (Ref. 5), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, “Power Distribution Limits”; Section 3.4, “Reactor Coolant System (RCS)”; and Section 3.6, “Containment Systems.”

Since diesel fuel oil, lube oil, and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. Additionally, sufficient lubricating oil supply must be available to ensure the capability to operate at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG skid-mounted day tank fuel requirements, as well as transfer capability from the 7 day storage tank to the skid-mounted 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 DG start attempts without recharging the air start receivers.

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 the starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated DG is required to be OPERABLE.

BASES (continued)

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.

A.1

In this Condition, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events, such as full load operation required after an inadvertent start while at minimum required level, or feed and bleed operations, which 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 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 < 287 gal per diesel engine, sufficient lubricating 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 to obtain 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.

(continued)

BASES

ACTIONS (continued)

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion of SR 3.8.3.3. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and 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, re-sampling 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 combinations 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 a high likelihood that the DG would still be capable of performing its intended function.

E.1

With starting air receiver pressure < 190 psig, sufficient capacity for five successive DG start attempts does not exist. However, as long as the receiver pressure is ≥ 170 psig (value does not account for instrument error), there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit of ≥ 190 psig (value does not account for instrument error). A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

(continued)

BASES

ACTIONS (continued)

F.1

With a Required Action and associated Completion Time not met, or one or more DG's 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 that there is an adequate inventory (≥ 56,754 gallons, value does not account for instrument error) of fuel oil in the storage tanks to support each DG's operation for 7 days at full load. The 7 day period is sufficient time to place the plant 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 is available to support at least 7 days of full load operation for each DG. The 287 gal requirement is based on the DG manufacturer consumption values for the run time of the DG. The DG lube oil sump is designed to hold adequate oil for 7 days of full-load operation without the level reaching the manufacturer's recommended minimum level.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.3

The tests listed below are a means of determining 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. For the purpose of this SR, only fuel oil that is transferred from the yard fuel oil storage tanks to the 7 day fuel oil storage tank for each DG or fuel oil added to the 7 day fuel oil storage tank through the storage tank fill lines is considered new fuel consistent with the Diesel Fuel Oil Testing Program, Specification 5.7.2.16. 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 of new fuel and conducting the tests to exceed 31 days. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil in accordance with ASTM D4057-1988 (Ref. 6);

b. Verify in accordance with the tests specified in ASTM D1298-1985 and ASTM D975-1990 (Ref. 6) that 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°, a kinematic viscosity at 40°C of ≥ 1.9 centistokes and ≤ 4.1 centistokes, and a flash point of ≥ 125°F; and

c. Verify that the new fuel oil has a clear and bright appearance with proper color when tested in accordance with ASTM D4176-1986 (Ref. 6).

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

Within 31 days following the initial new fuel oil sample, the fuel oil is analyzed to establish that the other properties specified in Table 1 of ASTM D975-1990 (Ref. 6) are met for new fuel oil when tested in accordance with ASTM D975-1990 (Ref. 6), except that the analysis for sulfur may be performed in accordance with ASTM D1552-1990 (Ref. 6) or ASTM D2622-1987 (Ref. 6). The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. This Surveillance ensures the availability of high quality fuel oil for the DGs.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

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

Particulate concentrations should be determined in accordance with ASTM D2276-1989, 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. Each of the four interconnected tanks which comprise a 7 day tank must be considered and tested separately.

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

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity (≥ 190 psig, value does not account for instrument error) for each DG is available. The system design requirements provide for a minimum of five engine start cycles without recharging. A start cycle is defined by the DG vendor, but usually is measured in terms of time (seconds of cranking) or engine cranking speed. The pressure specified in this SR is intended to reflect the lowest value at which the five starts 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, and contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system.

The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance.

SR 3.8.3.6

This SR verifies, by visual inspection, that the exposed fuel oil system piping is free of leaks. This test is performed while the DG is running to provide adequate assurance of piping leak tightness and weld integrity. The 18 month Frequency is based on engineering judgment and is consistent with the refueling cycle testing performed on the DGs.

SR 3.8.3.7

Draining of the fuel oil stored in the supply tanks, removal of accumulated sediment, and tank cleaning are required at 10 year intervals by Regulatory Guide 1.137 (Ref. 2), paragraph 2.f. To preclude the introduction of surfactants in the fuel oil system, the cleaning should be accomplished using sodium hypochlorite solutions, or their equivalent, rather than soap or detergents. This SR is for preventive maintenance. The presence of sediment does not necessarily represent a failure of this SR, provided that accumulated sediment is removed during performance of the Surveillance.

BASES

REFERENCES

1. Watts Bar FSAR, Section 8.3, “Onsite (Standby) Power System”.

2. Regulatory Guide 1.137, “Fuel Oil Systems for Standby Diesel Generators,” Revision 1, October, 1979.

3. ANSI N195-1976, “Fuel Oil Systems for Standby Diesel Generators,” Appendix B.

4. Watts Bar FSAR, Section 9.5.7, “Diesel Engine Lubrication System.”

5. Watts Bar FSAR, Section 15, “Accident Analysis” and Section 6 “Engineered Safety Features.”

6. ASTM Standards:

   D4057-1988, “Practice for Manual Sampling of Petroleum and Petroleum Products.”

   D975-1990, “Standard Specification for Diesel Fuel Oils.”

   D4176-1986, “Free Water and Particulate Contamination in Distillate Fuels.”

   D1552-1990, “Standard Test Method for Sulfur in Petroleum Products (High Temperature Method).”

   D2622-1987, “Standard Test Method for Sulfur in Petroleum Products (X-Ray Spectrographic Method).”

   D2276-1989, “Standard Test Method for Particulate Contamination in Aviation Fuel.”

   D1298-1985, “Standard Test Method for Density, Specific Gravity, or API Gravity of Crude Petroleum and Liquid Petroleum Products by Hydrometer Method.”

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 and preferred AC vital bus power (via inverters). 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 recommendations of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

125 V Vital DC Electrical Power Subsystem

The vital 125 VDC electrical power system is a Class 1E system whose safety function is to provide control power for engineered safety features equipment, emergency lighting, vital inverters, and other safety related DC powered equipment for the entire unit. The system capacity is sufficient to supply these loads and any connected non-safety loads during normal operation and to permit safe shutdown and isolation of the reactor for the “loss of all AC power” condition. The system is designed to perform its safety function subject to a single failure.

The 125V DC vital power system is composed of the four redundant channels (Channels I and III are associated with Train A and Channels II and IV are associated with Train B) and consists of four lead-acid-calcium batteries, eight battery chargers (including two pairs of spare chargers), four distribution boards, battery racks, and the required cabling, instrumentation and protective features. Each channel is electrically and physically independent from the equipment of all other channels so that a single failure in one channel will not cause a failure in another channel. Each channel consists of a battery charger which supplies normal DC power, a battery for emergency DC power, and a battery board which facilitates load grouping and provides circuit protection. These four channels are used to provide emergency power to the 120V AC vital power system which furnishes control power to the reactor protection system. No automatic connections are used between the four redundant channels.

Battery boards I, II, III, and IV have a charger normally connected to them and also have manual access to a spare (backup) charger for use upon loss of the normal charger.

(continued)

BASES

BACKGROUND

125 V Vital DC Electrical Power Subsystem (continued)

Additionally, battery boards I, II, III, and IV have manual access to the fifth vital battery system. The fifth 125V DC Vital Battery System is intended to serve as a replacement for any one of the four 125V DC vital batteries during their testing, maintenance, and outages with no loss of system reliability under any mode of operation.

Each of the vital DC electrical power subsystems provides the control power for its associated Class 1E AC power load group, 6.9 kV switchgear, and 480 V load centers. The vital DC electrical power subsystems also provide DC electrical power to the inverters, which in turn power the AC vital buses. Additionally, they power the emergency DC lighting system.

The vital DC power distribution system is described in more detail in Bases for LCO 3.8.9, “Distribution System - Operating,” and LCO 3.8.10, “Distribution Systems - Shutdown.”

Each vital battery has adequate storage capacity to carry the required load continuously for at least 4 hours in the event of a loss of all AC power (station blackout) without an accident or for 30 minutes with an accident considering a single failure. Load shedding of non-required loads will be performed to achieve the required coping duration for station blackout conditions.

Each 125 VDC vital battery is separately housed in a ventilated room apart from its charger and distribution centers, except for Vital Battery V. Each subsystem is located in an area separated physically and electrically from the other subsystem to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems, such as batteries, battery chargers, or distribution panels.

The batteries for the vital DC electrical power subsystems are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles, de-rated for minimum ambient temperature and the 100% design demand. The voltage limit is 2.13 V per cell, which corresponds to a total minimum voltage output of 128 V per battery (132 V for Vital Battery V). The criteria for sizing large lead storage batteries are defined in IEEE-485 (Ref. 5).

(continued)

BASES

BACKGROUND

125 V Vital DC Electrical Power Subsystem (continued)

Each Vital DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger also has sufficient capacity to restore the battery bank from the design minimum charge to its fully charged state within 12 hours (with accident loads being supplied) following a 30 minute AC power outage and in approximately 36 hours (while supplying normal steady state loads following a 2 hour AC power outage), (Ref. 6).

125 V Diesel Generator (DG) DC Electrical Power Subsystem

Control power for the DGs is provided by four DG battery systems, one per DG. Each system is comprised of a battery, a battery charger, distribution center, cabling, and cable ways. The DG 125V DC control power and field-flash circuits have power supplied from their respective 125V distribution panel. The normal supply of DC current is from the associated charger. The battery provides control and field-flash power when the charger is unavailable. The charger supplies the normal DC loads, maintains the battery in a fully charged condition, and recharges (480V AC available) the battery while supplying the required loads regardless of the status of the unit. The batteries are physically and electrically independent. The battery has sufficient capacity when fully charged to supply required loads for a minimum of four hours following a loss of normal power. Each battery is normally required to supply loads during the time interval between loss of normal feed to its charger and the receipt of emergency power to the charger from its respective DG.

BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Section 6 (Ref. 7), and in the FSAR, Section 15 (Ref. 7), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The vital DC electrical power system provides normal and emergency DC electrical power for the emergency auxiliaries, and control and switching during all power for the emergency auxiliaries, and control and switching during all MODES of operation. The DG battery systems provide DC power for the DGs.

The OPERABILITY of the DC sources 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 DC sources OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

Four 125V vital DC electrical power subsystems, each vital subsystem channel consisting of a battery bank, associated battery charger and the corresponding control equipment and interconnecting cabling supplying power to the associated DC bus within the channel; and four DG DC electrical power subsystems each consisting of a battery, a dual battery charger assembly, and the corresponding control equipment and interconnecting cabling are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (A00) or a postulated DBA. Loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

An OPERABLE vital DC electrical power subsystem requires all required batteries and respective chargers to be operating and connected to the associated DC buses.

The LCO is modified by one Note. The Note indicates that Vital Battery V may be substituted for any of the required vital batteries. However, the fifth battery cannot be declared OPERABLE until it is connected electrically in place of another battery and it has satisfied applicable Surveillance Requirements.

APPLICABILITY

The four vital DC electrical power sources and four DG DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe plant operation and to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOs 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 5 and 6 are addressed in the Bases for LCO 3.8.5, “DC Sources - Shutdown.”

BASES (continued)

ACTIONS

A.1

Condition A represents one vital channel 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 plant, minimizing the potential for complete loss of DC power to the affected train. The 2 hour limit is consistent with the allowed time for an inoperable DC distribution system train.

If one of the required vital DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger(s), or inoperable battery charger and associated inoperable battery), the remaining vital DC electrical power subsystem has the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure of the OPERABLE subsystem would, however, result in a situation where the ability of the 125V DC electrical power subsystem to support its required ESF function is not assured, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 8) and reflects a reasonable time to assess plant status as a function of the inoperable vital DC electrical power subsystem and, if the vital DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe plant shutdown.

B.1 and B.2

If the inoperable vital DC electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 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 plant to MODE 5 is consistent with the time required in Regulatory Guide 1.93 (Ref. 8).

(continued)

BASES (continued)

ACTIONS (continued)

C.1

Condition C represents one DG with a loss of ability to completely respond to an event. Since a subsequent single failure on the opposite train could result in a situation where the required ESF function is not assured, continued power operation should not exceed 2 hours. The 2 hour time limit is consistent with the allowed time for an inoperable vital DC electrical power subsystem.

D.1

If the DG DC electrical power subsystem cannot be restored to OPERABLE status in the associated Completion Time, the associated DG 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 for an inoperable DG, LCO 3.8.1, "AC Sources-Operating."

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1 and SR 3.8.4.2

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or a battery cell) in a fully charged state. The voltage requirements are based on the critical design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. The 7 day Frequency is consistent with manufacturer recommendations and IEEE-450 (Ref. 9).

SR 3.8.4.3

Verifying that for the vital batteries that the alternate feeder breakers to each required battery charger is open ensures that independence between the power trains is maintained. The 7 day Frequency is based on engineering judgment, is consistent with procedural controls governing breaker operation, and ensures correct breaker position.

SR 3.8.4.4

This SR demonstrates that the DG 125V DC distribution panel and associated charger are functioning properly, with all required circuit breakers closed and buses energized from normal power. The 7 day Frequency takes into account the redundant DG capability and other indications available in the control room that will alert the operator to system malfunctions.

SR 3.8.4.5 and SR 3.8.4.6

Visual inspection to detect corrosion of the battery cells and connections, or measurement of the resistance of each intercell, interrack, intertier, and terminal connection, provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The limits established for this SR must be no more than 20% above the resistance as measured during installation, or not above the ceiling value established by the manufacturer.

The 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.7

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 12 month Frequency for this SR is consistent with IEEE-450 (Ref. 9), which recommends detailed visual inspection of cell condition and rack integrity on a yearly basis.

SR 3.8.4.8, SR 3.8.4.9 and SR 3.8.4.10

Visual inspection and resistance measurements of intercell, interrack, intertier, and terminal connections provide an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anticorrosion material is used to help ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each terminal connection. The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR provided visible corrosion is removed during performance of SR 3.8.4.8. For the purposes of trending, inter-cell (vital and DG batteries) and inter-tier (vital and DG batteries) connections are measured from battery post to battery post. Inter-rack (vital batteries), inter-tier (DG Batteries), and terminal connections (vital and DG batteries) are measured from terminal lug to battery post.

The connection resistance limits for SR 3.8.4.9 and SR 3.8.4.10 shall be no more than 20% above the resistance as measured during installation, or not above the ceiling value established by the manufacturer.

The Surveillance Frequencies of 12 months is consistent with IEEE-450 (Ref. 9), which recommends cell to cell and terminal connection resistance measurement on a yearly basis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.11

This SR requires that each vital battery charger be capable of recharging its associated battery from a capacity or service discharge test while supplying normal loads, or alternatively, operating at current limit for a minimum of 4 hours at a nominal 125 VDC. These requirements are based on the design capacity of the chargers (Ref. 4) and their performance characteristic of current limit operation for a substantial portion of the recharge period. Battery charger output current is limited to 110% - 125% of the 200 amp rated output. Recharging the battery or testing for a minimum of 4 hours is sufficient to verify the output capability of the charger can be sustained, that current limit adjustments are properly set and that protective devices will not inhibit performance at current limit settings. According to Regulatory Guide 1.32 (Ref. 6), 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 plant during these demand occurrences. Verifying the capability of the charger to operate in a sustained current limit condition ensures that these requirements can be satisfied.

The Surveillance Frequency is acceptable, given the plant conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 18 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance may perturb the electrical distribution system and challenge safety systems. This Surveillance is normally performed during MODES 5 and 6 since it would require the DC electrical power subsystem to be inoperable during performance of the test. However, this Surveillance may be performed in MODES 1, 2, 3, or 4 provided the Vital Battery V is substituted in accordance with LCO Note 1. Credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.12

This SR requires that each diesel generator battery charger be capable of recharging its associated battery from a capacity or service discharge test while supplying normal loads, or alternatively, operating at current limit for a minimum of 4 1/2 hours at a nominal 125 VDC. This requirement is based on the design capacity of the chargers (Ref. 13) and their performance characteristic of current limit operation for a substantial portion of the recharge period. Battery charger output current is limited to a maximum of 140% of the 20 amp rated output. Recharging the battery verifies the output capability of the charger can be sustained, that current limit adjustments are properly set and that protective devices will not inhibit performance at current limit settings. According to Regulatory Guide 1.32 (Ref. 6), 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 plant during these demand occurrences. Verifying the capability of the charger to operate in a sustained current limit condition ensures that these requirements can be satisfied.

The Surveillance Frequency is acceptable, given the plant conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 18 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

For the DG DC electrical subsystem, this Surveillance may be performed in MODES 1, 2, 3, or 4 in conjunction with LCO 3.8.1.B since the DG DC electrical power subsystem supplies loads only for the inoperable diesel generator and would not otherwise challenge safety systems supplied from vital electrical distribution systems. Additionally, credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.13

A battery service test is a special test of battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length should correspond to worst case design duty cycle requirements based on Reference 10 and 12.

The Surveillance Frequency of 18 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 6) and Regulatory Guide 1.129 (Ref. 11), 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.

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

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.13 (continued)

The reason for Note 2 is that performing the Surveillance may perturb the vital electrical distribution system and challenge safety systems. However, this Surveillance may be performed in MODES 1, 2, 3, or 4 provided that Vital Battery V is substituted in accordance with LCO Note 1. For the DG DC electrical subsystem, this surveillance may be performed in MODES 1, 2, 3, or 4 in conjunction with LCO 3.8.1.B since the supplied loads are only for the inoperable diesel generator and would not otherwise challenge safety system loads which are supplied from vital electrical distribution systems. Additionally, credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

SR 3.8.4.14

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

A battery modified performance discharge test is described in the Bases for 3.8.4.13. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.14; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.14 while satisfying the requirements of SR 3.8.4.13 at the same time.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 9) and IEEE-485 (Ref. 5). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.14 (continued)

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 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 9), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ 10% below the manufacturer rating. These Frequencies are consistent with the recommendations in IEEE-450 (Ref. 9).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance may perturb the vital electrical distribution system and challenge safety systems. However, this Surveillance may be performed in MODES 1, 2, 3, or 4 provided that Vital Battery V is substituted in accordance with LCO Note 1. For the DG DC electrical subsystem, this surveillance may be performed in MODES 1, 2, 3, or 4 in conjunction with LCO 3.8.1.B since the supplied loads are only for the inoperable diesel generator and would not otherwise challenge safety system loads which are supplied from vital electrical distribution systems. Additionally, credit may be taken for unplanned events that satisfy this SR. Examples of unplanned events may include:

1) Unexpected operational events which cause the equipment to perform the function specified by this Surveillance, for which adequate documentation of the required performance is available; and

2) Post corrective maintenance testing that requires performance of this Surveillance in order to restore the component to OPERABLE, provided the maintenance was required, or performed in conjunction with maintenance required to maintain OPERABILITY or reliability.

(continued)

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, General Design Criterion 17, “Electric Power System.”

2. Regulatory Guide 1.6, “Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems,” U.S. Nuclear Regulatory Commission, March 10, 1971.

3. IEEE-308-1971, “IEEE Standard Criteria for Class 1E Power Systems for Nuclear Power Generating Stations,” Institute of Electrical and Electronic Engineers.

4. Watts Bar FSAR, Section 8.3.2, “DC Power System.”

5. IEEE-485-1983, “Recommended Practices for Sizing Large Lead Storage Batteries for Generating Stations and Substations,” Institute of Electrical and Electronic Engineers.

6. Regulatory Guide 1.32, “Criteria for Safety-Related Electric Power Systems for Nuclear Power Plants,” February 1977, U.S. Nuclear Regulatory Commission.

7. Watts Bar FSAR, Section 15, “Accident Analysis” and Section 6 “Engineered Safety Features.”

8. Regulatory Guide 1.93, “Availability of Electric Power Sources,” U.S. Nuclear Regulatory Commission, December 1974.

9. IEEE-450-1980/1995, “IEEE Recommended Practice for Maintenance, Testing and Replacement of Vented Lead - Acid Batteries for Stationary Applications,” Institute of Electrical and Electronics Engineers, Inc.

10. TVA Calculation EDQ00023620070003, “125V DC Vital Battery System Analysis”

11. Regulatory Guide 1.129, “Maintenance Testing and Replacement of Large Lead Storage Batteries for Generating Stations and Subsystems,” U.S. Nuclear Regulatory Commission, February 1978.

12. TVA Calculation WBN EEB-EDQ00023620070003, “125V DC Vital Battery System Analysis.”

13. Watts Bar FSAR, Section 8.3.1, “AC Power System.”

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, Section 6 (Ref. 1) and Section 15 (Ref. 1), assume that Engineered Safety Feature systems are OPERABLE. The vital DC electrical power system provides normal and emergency DC electrical power for the emergency auxiliaries, and control and switching during all MODES of operation. The DG battery systems provide DC power for the DGs.

The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems’ OPERABILITY.

The OPERABILITY of the minimum DC electrical power sources during MODES 5 and 6, and during movement of irradiated fuel assemblies ensures that:

a. The plant 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 plant status; and

c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

The DC sources satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The 125V Vital DC electrical power subsystems, each vital subsystem channel consisting of a battery bank, associated battery charger, and the corresponding control equipment and interconnecting cabling within the channel; and the DG DC electrical power subsystems, each consisting of a battery, a battery charger, and the corresponding control equipment and interconnecting cabling, are required to be OPERABLE to support required trains of the distribution systems required OPERABLE by LCO 3.8.10, “Distribution Systems - Shutdown” and the required DGs required OPERABLE by LCO 3.8.2, “AC Sources - Shutdown.” As a minimum, one vital DC electrical power train (i.e., Channels I and III, or II and IV) and two DG DC electrical power subsystems (i.e., 1A-A and 2A-A or 1B-B and 2B-B) shall be OPERABLE. This ensures the availability of sufficient DC electrical power sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

The LCO is modified by one Note. The Note indicates that Vital Battery V may be substituted for any of the required vital batteries. However, the fifth battery cannot be declared OPERABLE until it is connected electrically in place of another battery and it has satisfied applicable Surveillance Requirements.

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Required features needed to mitigate a fuel handling accident are available;
b. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and
c. Instrumentation and control capability is available for monitoring and maintaining the plant in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4.

BASES (continued)

ACTIONS

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

If two trains are required by LCO 3.8.10, the remaining train with DC power available may be capable of supporting sufficient systems to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features inoperable with the associated vital DC power source(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCO 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, and operations involving positive reactivity additions). The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory, provided the required SDM is maintained.

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 immediately initiate action to restore the required vital 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 vital 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.

B.1

If one or more DG DC electrical power subsystem cannot be restored to OPERABLE status in the associated Completion Time, the associated DG 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 for an inoperable DG, LCO 3.8.2, “AC Sources - Shutdown.”

BASES (continued)

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 3.8.4.14. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. Watts Bar FSAR, Section 15, “Accident Analysis” and Section 6, “Engineered Safety Features.”

2. Watts Bar FSAR, Section 8.0, “Electric Power.”

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND	This LCO delineates the limits on battery float current, electrolyte temperature, electrolyte level, and cell float voltage for the 125V vital DC electrical power subsystem and the diesel generator (DG) 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 the FSAR, Section 6 (Ref. 1) and Section 15 (Ref. 1), assume Engineered Safety Feature systems are OPERABLE. The vital DC electrical power system provides normal and emergency DC electrical power for the emergency auxiliaries, and control and switching during all MODES of operation. The DG battery systems provide DC power for the DGs. 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 plant. This includes maintaining at least one train of DC sources OPERABLE during accident conditions, in the event of: a. An assumed loss of all offsite AC power or all onsite AC power; and b. A worst case single failure. Battery parameters satisfy the Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Battery 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 Category A and B limits not met.
APPLICABILITY	The battery cell parameters are required solely for the support of the associated vital DC and DG DC electrical power subsystems. Therefore, battery electrolyte is only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

BASES (continued)

ACTIONS

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

With 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 in the accompanying LCO, 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 operation is permitted for a limited period.

The pilot cell electrolyte level and float voltage are required to be verified to meet the Category C limits within 1 hour (Required Action A.1). This check will provide 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 cells. 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 operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. With the 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 prior to declaring the battery inoperable.

B.1

With one or more batteries with one or more battery cell parameters outside the Category C limits for any connected cell, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding vital DC or DG DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as not completing the Required Actions of Condition A within the required Completion Time or average electrolyte temperature of

(continued)

BASES (continued)

ACTIONS

B.1 (continued)

representative cells falling below 60°F for the vital batteries or 50°F for DG batteries, are also cause for immediately declaring the associated vital DC or DG DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 2), 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. 2). In addition, within 24 hours of a battery discharge < 110 V (113.5V for Vital Battery V or 106.5 for DG batteries) or a battery overcharge > 150 V (155 V for Vital Battery V or 145 V for DG batteries), 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 (113.5 V for Vital Battery V or 106.5 V for DG batteries), do not constitute a battery discharge provided the battery terminal voltage and float current return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 2), 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 for the vital batteries and ≥ 50°F for the DG batteries, is consistent with a recommendation of IEEE-450 (Ref. 2), that states that the temperature of electrolytes in representative 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 recommendations.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Table 3.8.6-1

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

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

The Category A limits specified for electrolyte level are based on manufacturer recommendations and are consistent with the guidance in IEEE-450 (Ref. 2), 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 above the specified maximum level during equalizing 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. 2) 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 the recommendations of IEEE-450 (Ref. 2), which states that prolonged operation of cells < 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 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. 2), 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 fully charged, nominal specific gravity) with the average of all connected cells > 1.205 (0.010 below the manufacturer fully charged, nominal specific gravity). These values are based on manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell will not mask overall degradation of the battery.

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

The Category C limits 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 limits for float voltage is based on IEEE-450 (Ref. 2), 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 limits of average specific gravity ≥ 1.195 is based on manufacturer recommendations (0.020 below the manufacturer recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery.

The footnotes to Table 3.8.6-1 are applicable to Category A, B, and C specific gravity. Footnote b to 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 for vital batteries and < 1.0 amps for DG batteries. This current provides, in general, an indication of overall battery condition.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS (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 charger current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 2). Footnote c to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity for up to 31 days following a battery recharge. Within 31 days each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements may be made in less than 31 days.

REFERENCES

1. Watts Bar FSAR, Section 15, “Accident Analysis,” and Section 6, “Engineered Safety Features.”

2. IEEE Std 450-1980/1995, “IEEE Recommended Practice for Maintenance, Testing and Replacement of Vented Lead - Acid Batteries for Stationary Applications,” Institute of Electrical and Electronics Engineers, Inc.

3. Watts Bar FSAR, Section 8, “Electric Power.”

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters - Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the AC vital buses because of the stability and reliability they achieve. There are two unit inverters (Unit 1 and Unit 2) and one spare inverter per channel, each of which is capable of supplying its associated AC vital buses, making a total of twelve inverters. The function of the inverter is to provide AC electrical power to the AC vital buses. The inverters can be powered from an internal AC source/rectifier or from the vital battery. The vital battery provides an uninterruptible power source for the instrumentation and controls for the Reactor Protective System (RPS) and the Engineered Safety Feature Actuation System (ESFAS). The spare inverters will be used as spare uninterruptible power sources; however they will not have a regulated transformer bypass source. Specific details on inverters and their operating characteristics are found in the Watts Bar FSAR, Section 8 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Section 6 (Ref. 2) and Section 15 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls 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 3.4, “Reactor Coolant System (RCS);” and Section 3.6, “Containment Systems.”

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the plant. This includes maintaining required AC vital buses OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

Inverters are a part of the distribution systems and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The inverters ensure the availability of AC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (A00) or a postulated DBA.

Maintaining the required inverters OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The twelve inverters (one Unit 1, one Unit 2 and one spare per channel) ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the 6.9 kV shutdown boards are de-energized.

OPERABLE inverters require the associated AC vital bus to be powered by the inverter with output voltage and frequency within tolerances and power input to the inverter from a 125 VDC vital battery. Alternatively, power supply may be from an internal AC source via rectifier as long as the vital battery is available as the uninterruptible power supply. The inverters have an associated bypass supply provided by a regulated transformer that is automatically connected to the associated AC vital bus in the event of inverter failure or overload. The bypass supply is not battery-backed and thus does not meet requirements for inverter operability. The spare inverters do not have an associated bypass supply. Additionally, the inverter channel must not be connected to the cross train 480 V power supply.

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 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.

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, “Inverters - Shutdown.”

BASES (continued)

ACTIONS

A.1

With one inverter in a channel inoperable, its associated AC vital bus becomes inoperable until it is re-energized from its associated regulated transformer bypass source, inverter internal AC source, or spare inverters.

For this reason, a Note has been included in Condition A requiring the entry into the Conditions and Required Actions for LCO 3.8.9, “Distribution Systems - Operating.” This ensures that the vital bus is re-energized within 2 hours.

Required Action A.1 allows 24 hours to fix the inoperable inverter and return it to service. The 24 hour limit is based upon engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the plant is exposed because of the inverter inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the AC vital bus is powered from its associated regulated transformer bypass source it is relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the AC vital buses is the preferred source for powering instrumentation trip setpoint devices. Alternatively, an inverter may be restored to OPERABLE status by substituting its spare inverters and performing the required surveillance.

B.1 and B.2

If the inoperable devices or components cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 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.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed including those from the associated vital battery boards and 480 V shutdown boards, and AC vital buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation of the RPS and ESFAS connected to the AC vital buses. Upon placing a spare inverter in service, the spare inverter is considered inoperable until this surveillance is completed. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

REFERENCES

1. Watts Bar FSAR, Section 8.3.1, “AC Power System.”

2. Watts Bar FSAR, Section 15, “Accident Analysis,” and Section 6, “Engineered Safety Features.”

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters - Shutdown

BASES

BACKGROUND

A description of the inverters is provided in the Bases for LCO 3.8.7, “Inverters - Operating.”

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Section 6 (Ref. 1) and Section 15 (Ref. 1), assume Engineered Safety Feature systems are OPERABLE. The DC to AC inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protective System and Engineered Safety Features Actuation System instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum inverters to each AC vital bus during MODES 5 and 6 ensures that:

a. The plant 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 plant status; and

c. Adequate power is available to mitigate events postulated during shutdown, such as a fuel handling accident.

The inverters were previously identified as part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

The inverters ensure the availability of electrical power for the instrumentation for systems required to shutdown the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. The battery powered inverters provide uninterruptible supply of AC electrical power to the AC vital buses even if the 6.9 kV shutdown boards are de-energized. OPERABILITY of the inverters requires that the AC vital buses required by LCO 3.8.10, “Distribution Systems - Shutdown” be powered by the inverter. As a minimum, either the Channel I and III or II and IV inverters for each unit (or spare inverters) shall be OPERABLE to support the distribution systems required by LCO 3.8.10. The unit inverters have an associated bypass supply provided by a regulated transformer that is automatically connected to the associated AC vital bus in the event of inverter failure or overload. The bypass supply is not battery-backed and thus does not meet requirements for inverter operability. The spare inverters do not have an associated bypass supply. Additionally, the inverter channel must not be connected to the cross-train 480 V power supply. This ensures the availability of sufficient inverter power sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies provide assurance that:

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

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

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

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

BASES (continued)

ACTIONS

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

If two trains are required by LCO 3.8.10, the remaining OPERABLE Inverters may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for positive reactivity additions. By the allowance of the option to declare required features inoperable with the associated inverter(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCOs' 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, and operations involving positive reactivity additions). The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory, provided the required SDM is maintained.

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 inverters and to continue this action until restoration is accomplished in order to provide the necessary inverter 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 inverters should be completed as quickly as possible in order to minimize the time the plant safety systems may be without power or powered from its associated regulated transformer bypass source.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the required inverters are functioning properly with all required circuit breakers closed including those from the associated vital battery boards and 480 V shutdown boards and AC vital buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation connected to the AC vital buses. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions. Upon placing a spare inverter in service, the spare inverter is considered inoperable until this surveillance is completed.

BASES (continued)

REFERENCES

1. Watts Bar FSAR, Section 15, “Accident Analysis,” and Section 6, “Engineered Safety Features.”

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems - Operating

BASES

BACKGROUND

The onsite Class 1E AC electrical power distribution system is divided by train into two redundant and independent AC electrical power distribution subsystems.

The AC electrical power subsystem includes four 6.9 kV shutdown boards. Each 6.9 kV shutdown board has access to the two separate and independent preferred offsite sources of power as well as a dedicated onsite diesel generator (DG) source. Usually, one of the two offsite sources will be the normal power source for a 6.9 kV shutdown board, and the other offsite source will be the alternate power source. Transfers from the normal source to the alternate source may be manual or automatic. Automatic transfers only occur when the relay logic is tripping a transmission line and the associated common station service transformers. Only manual transfers are permitted from alternate to normal. Additionally, the maintenance source to the 6.9kV shutdown board can be used as an offsite power source. Transferring the 6.9 kV shutdown board to the maintenance power source is done manually from the normal or alternate power source. For a loss of offsite power to the 6.9 kV shutdown boards, the onsite emergency power system supplies power to the 6.9 kV shutdown boards. Control power for the 6.9 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 AC Distribution System includes the 480 V shutdown boards and associated supply transformers, load centers, and protective devices shown in Table B 3.8.9-1.

The 120 VAC vital buses are arranged in four load groups and are normally powered from the unit inverters or spare inverters and DC Boards I, II, III, and IV. An alternate power supply for the vital buses is a regulated transformer bypass source powered from the same train as the associated unit inverter, and its use is governed by LCO 3.8.7, “Inverters - Operating.”

There are four independent 125 VDC electrical power distribution buses. Each bus receives normal power from an independent 480 VAC shutdown board via its associated battery charger. Upon loss of 480 VAC shutdown board power, the DC buses are energized by their connected battery banks.

The list of all required distribution buses is presented in Table B 3.8.9-1.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Section 6 (Ref. 1), and in the FSAR, Section 15 (Ref. 1), assume ESF systems are OPERABLE. The AC, vital DC, and AC vital bus 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 3.4, "Reactor Coolant System (RCS);" and Section 3.6, "Containment Systems."

The OPERABILITY of the AC, vital DC, and AC vital bus 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 power distribution systems OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

The distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, vital DC, and AC vital bus 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 AC, vital DC, and AC vital bus electrical power distribution subsystems are required to be OPERABLE.

Maintaining the Train A and Train B AC, four channels of vital DC, and four channels of AC vital bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

OPERABLE AC electrical power distribution subsystems require the associated buses, load centers, motor control centers, and distribution panels 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. OPERABLE vital bus electrical power distribution subsystems

(continued)

BASES

LCO (continued)

require the associated buses to be energized to their proper voltage from the associated unit or spare inverter via inverted DC voltage, unit or spare inverter using internal AC source, or the regulated transformer bypass source.

In addition, tie breakers between redundant safety related AC, vital 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 that 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 are considered inoperable. This applies to the onsite, safety related redundant electrical power distribution subsystems. It does not, however, preclude redundant 6.9 kV shutdown boards from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 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 5 and 6 are covered in the Bases for LCO 3.8.10, “Distribution Systems - Shutdown.”

ACTIONS

A.1

With one or more required AC shutdown boards, load centers, motor control centers, or distribution panels, except AC vital buses, in one train inoperable, the remaining AC electrical power distribution subsystem in the other train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. 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

(continued)

BASES

ACTIONS

A.1 (continued)

supported. Therefore, the required AC shutdown boards, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours.

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

a. The potential for decreased safety if the plant operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the plant to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

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 restored OPERABLE, the LCO may already have been not met for up to 2 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

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

(continued)

BASES

ACTIONS (continued)

B.1

With one or more AC vital buses in one channel inoperable, the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the plant and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated unit or spare inverter via inverted DC, unit or spare inverter using internal AC source, or regulated transformer bypass source.

Condition B represents one or more AC vital buses in one channel without power; potentially both the DC source and the associated AC source are nonfunctioning. In this situation, the plant is significantly more vulnerable to a complete loss of all non-interruptible 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 vital buses and restoring power to the affected vital bus.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate vital AC power. Taking exception to LCO 3.0.2 for components without adequate vital AC power, that would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

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

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate vital AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

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

The 2 hour Completion Time takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

(continued)

BASES

ACTIONS

B.1 (continued)

The second Completion Time for Required Action B.1 establishes a limit on the maximum 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 could lead to a total of 10 hours, since initial failure of the LCO, to restore the vital bus distribution system. At this time, an AC train could again become inoperable, and vital bus distribution 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 will result 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 to fail to meet the LCO indefinitely.

C.1

With one or more vital DC buses 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 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 subsystem could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition C represents one or more trains without adequate DC power; potentially both with 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 train(s) and restoring power to the affected train(s).

(continued)

BASES

ACTIONS

C.1 (continued)

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

a. The potential for decreased safety by requiring a change in plant conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

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

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

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 2).

The second Completion Time for Required Action C.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 C 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 could lead to a total of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution 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 will result in establishing the “time zero” at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 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

With two trains with one or more inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY, and other vital functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required AC, vital DC, and AC vital bus 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 trains is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, vital DC, and AC vital bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. Watts Bar FSAR, Section 6 “Engineering Safety Features,” Section 8 “Electric Power,” and Section 15 “Accident Analysis.”

2. Regulatory Guide 1.93, “Availability of Electric Power Sources,” U.S. Nuclear Regulatory Commission, December 1974.

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	TRAIN A*	TRAIN B*
AC safety buses	6900 V	Shutdown Board 1A-A, 2A-A	Shutdown Board 1B-B, 2B-B
	480 V	Shutdown Board 1A1-A, 1A2-A 2A1-A, 2A2-A Rx MOV Board 1A1-A, 1A2-A 2A1-A**, 2A2-A C & A Vent Board 1A1-A, 1A2-A 2A1-A, 2A2-A Diesel Aux Board 1A1-A, 1A2-A 2A1-A, 2A2-A Rx Vent Board 1A-A, 2A-A**	Shutdown Board 1B1-B, 1B2-B 2B1-B, 2B2-B Rx MOV Board 1B1-B, 1B2-B 2B1-B**, 2B2-B C & A Vent Board 1B1-B, 1B2-B 2B1-B, 2B2-B Diesel Aux Board 1B1-B, 1B2-B 2B1-B, 2B2-B Rx Vent Board 1B-B, 2B-B**
AC vital buses	120 V	Vital channel 1-I Vital channel 2-I Vital channel 1-III Vital channel 2-III	Vital channel 1-II Vital channel 2-II Vital channel 1-IV Vital channel 2-IV
DC buses	125 V	Board I Board III	Board II Board IV

* Each train of the AC and DC electrical power distribution systems is a subsystem.

** For Unit 2, 480V Reactor MOV Boards 2A1-A and 2B1-B and 480V Reactor Vent Boards 2A-A and 2B-B are available for economic and operational convenience. The boards are considered part of the Unit 2 Electrical Power Distribution System and meet Unit 2 TS Requirements and testing only while connected. WBN Unit 2 is designed to be operated, shutdown, and maintained in a safe shutdown status without any of these boards or their loads. As such, the boards may be disconnected from service without entering an LCO provided their loads are not substituting for a T/S required load.

3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems - Shutdown

BASES

BACKGROUND

A description of the AC, vital DC, and AC vital bus electrical power distribution systems is provided in the Bases for LCO 3.8.9, “Distribution Systems - Operating.”

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the FSAR, Section 6 (Ref. 1) and Section 15 (Ref. 1), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, vital DC, and AC vital bus 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, vital DC, and AC vital bus 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, vital DC, and AC vital bus electrical power distribution subsystems during MODES 5 and 6, and during movement of irradiated fuel assemblies ensures that:

a. The plant 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 plant status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

The AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

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

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

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

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

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

c. Instrumentation and control capability is available for monitoring and maintaining the plant in a cold shutdown condition and refueling condition.

The AC, vital DC, and AC vital bus electrical power distribution subsystems requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9.

BASES (continued)

ACTIONS

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 trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, and fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions).

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

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal (RHR) 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 ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR inoperable, which results in taking the appropriate RHR 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.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the AC, vital DC, and AC vital bus electrical power distribution subsystems are functioning properly, with all the required buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the capability of the electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. Watts Bar FSAR, Section 8.0, “Electric Power,” Section 15, “Accident Analysis,” and Section 6, “Engineered Safety Features.”

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentrations of the Reactor Coolant System (RCS), the refueling canal, and the refueling cavity during refueling ensures that the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration limit is specified in the COLR. Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of $k_{eff} \leq 0.95$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures.

GDC 26 of 10 CFR 50, Appendix A, requires that two independent reactivity control systems of different design principles be provided (Ref. 1). One of these systems must be capable of holding the reactor core subcritical under cold conditions. The Chemical and Volume Control System (CVCS) is the system capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration.

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized and the vessel head is unbolted, the head is slowly moved to the refueling cavity. The refueling canal and the refueling cavity are then flooded with borated water from the refueling water storage tank through the open reactor vessel by gravity feeding or by the use of the Residual Heat Removal (RHR) System pumps.

The pumping action of the RHR System in the RCS and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added concentrated boric acid with the water in the refueling canal.

(continued)

BASES

BACKGROUND (continued)

The RHR System is in operation during refueling (see LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level," and LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level") to provide forced circulation in the RCS and to assist in maintaining the boron concentrations in the RCS, the refueling canal, and the refueling cavity above the COLR limit.

APPLICABLE SAFETY ANALYSES

During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident in the accident analysis and is conservative for MODE 6. The boron concentration limit specified in the COLR is based on the core reactivity at the beginning of each fuel cycle (the end of refueling) and includes an uncertainty allowance.

The required boron concentration and the plant refueling procedures that verify the correct fuel loading plan (including full core mapping) ensure that the k_{eff} of the core will remain $\leq$ 0.95 during the refueling operation. Hence, at least a 5% $\Delta k/k$ margin of safety is established during refueling.

During refueling, the water volume in the spent fuel pool, the transfer canal, the refueling canal, the refueling cavity, and the reactor vessel form a single mass. As a result, the soluble boron concentration is relatively the same in each of these volumes.

The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires that a minimum boron concentration be maintained in the RCS, the refueling canal, and the refueling cavity while in MODE 6. The boron concentration limit specified in the COLR ensures that a core k_{eff} of $\leq$ 0.95 is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.

APPLICABILITY

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a $k_{eff} \leq 0.95$. Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM) - T_{avg} > 200 °F," and LCO 3.1.2, "SHUTDOWN MARGIN (SDM) - $T_{avg} \leq$ 200 °F," ensure that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical (Ref. 4).

BASES (continued)

ACTIONS

A.1 and A.2

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of any coolant volume in the RCS, the refueling canal, or the refueling cavity is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately.

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position.

A.3

In addition to immediately suspending CORE ALTERATIONS or positive reactivity additions, boration to restore the concentration must be initiated immediately.

In determining the required combination of boration flow rate and concentration, no unique Design Basis Event must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible, the operator should begin boration with the best source available for unit conditions.

Once actions have been initiated, they must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR ensures that the coolant boron concentration in the RCS, the refueling canal, and the refueling cavity is within the COLR limits. The boron concentration of the coolant in each volume is determined periodically by chemical analysis.

A minimum Frequency of once every 72 hours is a reasonable amount of time to verify the boron concentration of representative samples. The Frequency is based on operating experience, which has shown 72 hours to be adequate.

BASES (continued)

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, Section III, GDC 26, “Reactivity Control System Redundancy and Capability.”

2. Watts Bar FSAR, Section 15, “Accident Analysis.”

3. Not Used.

4. Watts Bar FSAR, Section 4.3.1.6, “Shutdown Margin for Refueling.”

B 3.9 REFUELING OPERATIONS

B 3.9.2 Unborated Water Source Isolation Valves

BASES

BACKGROUND	During MODE 6 operations, all isolation valves for reactor makeup water sources containing unborated water that are connected to the Reactor Coolant System (RCS) must be closed to prevent unplanned boron dilution of the reactor coolant. The isolation valves must be secured in the closed position. The Chemical and Volume Control System is capable of supplying borated and unborated water to the RCS through various flow paths. Since a positive reactivity addition made by reducing the boron concentration is inappropriate during MODE 6, isolation of all unborated water sources prevents an unplanned boron dilution.
APPLICABLE SAFETY ANALYSES	The possibility of an inadvertent boron dilution event (Ref. 1) occurring during MODE 6 refueling operations is precluded by adherence to this LCO, which requires that potential dilution sources be isolated. Closing the required valves during refueling operations prevents the flow of unborated water to the filled portion of the RCS. The valves are used to isolate unborated water sources. These valves have the potential to indirectly allow dilution of the RCS boron concentration in MODE 6. By isolating unborated water sources, a safety analysis for an uncontrolled boron dilution accident in accordance with the Standard Review Plan (Ref. 2) is not required for MODE 6. The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	This LCO requires that flow paths to the RCS from unborated water sources be isolated to prevent unplanned boron dilution during MODE 6 and thus avoid a reduction in SDM.

BASES (continued)

APPLICABILITY

In MODE 6, this LCO is applicable to prevent an inadvertent boron dilution event by ensuring isolation of all sources of unborated water to the RCS.

For all other MODES, the boron dilution accident was analyzed and was found to be capable of being mitigated.

ACTIONS

The ACTIONS table has been modified by a Note that allows separate Condition entry for each unborated water source isolation valve.

A.1

Continuation of CORE ALTERATIONS is contingent upon maintaining the unit in compliance with this LCO. With any valve used to isolate unborated water sources not secured in the closed position, all operations involving CORE ALTERATIONS must be suspended immediately. The Completion Time of “immediately” for performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

Condition A has been modified by a Note to require that Required Action A.3 be completed whenever Condition A is entered.

A.2

Preventing inadvertent dilution of the reactor coolant boron concentration is dependent on maintaining the unborated water isolation valves secured closed. Securing the valves in the closed position ensures that the valves cannot be inadvertently opened. The Completion Time of “immediately” requires an operator to initiate actions to close an open valve and secure the isolation valve in the closed position immediately. Once actions are initiated, they must be continued until the valves are secured in the closed position.

A.3

Due to the potential of having diluted the boron concentration of the reactor coolant, SR 3.9.1.1 (verification of boron concentration) must be performed whenever Condition A is entered to demonstrate that the required boron concentration exists. The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

These valves are to be secured closed to isolate possible dilution paths. The likelihood of a significant reduction in the boron concentration during MODE 6 operations is remote due to the large mass of borated water in the refueling cavity and the fact that all unborated water sources are isolated, precluding a dilution. The boron concentration is checked every 72 hours during MODE 6 under SR 3.9.1.1. This Surveillance demonstrates that the valves are closed through a system walkdown. The 31 day Frequency is based on engineering judgment and is considered reasonable in view of other administrative controls that will ensure that the valve opening is an unlikely possibility.

REFERENCES

1. Watts Bar FSAR, Section 15.2.4, “Uncontrolled Boron Dilution.”

2. NUREG-0800, Standard Review Plan, Section 15.4.6, “Chemical and Volume Control System Malfunction that Results in a Decrease in Boron Concentration in the RCS.”

B 3.9 REFUELING OPERATIONS

B 3.9.3 Nuclear Instrumentation

BASES

BACKGROUND

The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The installed source range neutron flux monitors are part of the Neutron Monitoring System (NMS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core.

The installed primary source range neutron flux monitors are fission chambers. The detectors monitor the neutron flux in counts per second. The instrument range covers six decades of neutron flux (1E+6 cps) with an instrument accuracy of 5% of the countrate. The detectors also provide continuous visual indication in the control room and an audible alarm to alert operators to a possible dilution accident. The NMS is designed in accordance with the criteria presented in Reference 1.

APPLICABLE SAFETY ANALYSES

Two OPERABLE source range neutron flux monitors are required to provide a signal to alert the operator to unexpected changes in core reactivity such as with a boron dilution accident (Ref. 2) or an improperly loaded fuel assembly. The need for a safety analysis for an uncontrolled boron dilution accident is eliminated by isolating all unborated water sources as required by LCO 3.9.2, "Unborated Water Source Isolation Valves."

The source range neutron flux monitors satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

This LCO requires that two source range neutron flux monitors be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity.

BASES (continued)

APPLICABILITY

In MODE 6, the source range neutron flux monitors must be OPERABLE to determine changes in core reactivity. There are no other direct means available to check core reactivity levels. In MODES 2, 3, 4, and 5, these same installed source range detectors and circuitry are also required to be OPERABLE by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."

ACTIONS

A.1 and A.2

With only one source range neutron flux monitor OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and positive reactivity additions must be suspended immediately. Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

B.1

With no source range neutron flux monitor OPERABLE, actions to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, actions shall be continued until a source range neutron flux monitor is restored to OPERABLE status.

B.2

With no source range neutron flux monitor OPERABLE, there are no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are not to be made, the core reactivity condition is stabilized until the source range neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration. The Frequency of once per 12 hours ensures that unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this time period.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

SR 3.9.3.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified similarly for the same instruments in LCO 3.3.1.

SR 3.9.3.2

SR 3.9.3.2 is the performance of a CHANNEL CALIBRATION every 18 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the source range neutron flux monitors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. Title 10, Code of Federal Regulations, Part 50, Appendix A, "General Design Criteria for Nuclear Power Plants:"

   GDC 13, "Instrumentation and Control,"

   GDC 26, "Reactivity Control System Redundancy and Capability,"

   GDC 28, "Reactivity Limits," and

   GDC 29, "Protection Against Anticipated Operational Occurrences."

2. Watts Bar FSAR, Section 15.2.4, "Uncontrolled Boron Dilution."

B 3.9 REFUELING OPERATIONS

B 3.9.4 RESERVED FOR FUTURE ADDITION

B 3.9 REFUELING OPERATIONS

B 3.9.5 Residual Heat Removal (RHR) and Coolant Circulation - High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchanger(s), where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown or decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and the bypass. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200 °F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. One train of the RHR System is required to be operational in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to prevent this challenge. The LCO does permit de-energizing the RHR pump for short durations, under the condition that the boron concentration is not diluted. This conditional de-energizing of the RHR pump does not result in a challenge to the fission product barrier.

Although the RHR System does not meet a specific criterion of 10 CFR 50.36(c)(2)(ii), it was identified in 10CFR 50.36(c)(2)(ii) as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification.

BASES (continued)

LCO

Only one RHR loop is required for decay heat removal in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange. Only one RHR loop is required to be OPERABLE, because the volume of water above the reactor vessel flange provides backup decay heat removal capability. At least one RHR loop must be OPERABLE and in operation to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop includes an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path and to determine the low end temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs. Both RHR pumps may be aligned to the Refueling Water Storage Tank (RWST) to support continued filling of the refueling cavity or for performance of RHR injection testing. During these modes of operation, the wide range RCS temperature indicators are used to indicate RCS temperature since the RHR temperature elements indicate RWST temperature when RHR pump suction is from the RWST. The flow path for these modes of operation starts at the RWST and is supplied to the RCS cold legs (or hot legs for hot leg injection testing). If only one pump is in operation, then hot leg injection testing must be done under the provisions of the NOTE discussed in the following paragraph.

The LCO is modified by a Note that allows the required operating RHR loop to be removed from service for up to 1 hour per 8 hour period provided no operations are permitted that would cause a reduction of the RCS boron concentration. Boron concentration reduction is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles and RCS to RHR isolation valve testing. During this 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling cavity.

BASES (continued)

APPLICABILITY

One RHR loop must be OPERABLE and in operation in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to provide decay heat removal. The 23 ft water level was selected because it corresponds to the 23 ft requirement established for fuel movement in LCO 3.9.7, "Refueling Cavity Water Level." Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, "Reactor Coolant System (RCS)," and Section 3.5, "Emergency Core Cooling Systems (ECCS)." RHR loop requirements in MODE 6 with the water level < 23 ft are located in LCO 3.9.6, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

RHR loop requirements are met by having one RHR loop OPERABLE and in operation, except as permitted in the Note to the LCO.

A.1

If RHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations cannot occur by the addition of water with a lower boron concentration than that contained in the RCS because all of unborated water sources are isolated.

A.2

If RHR loop requirements are not met, actions shall be taken immediately to suspend loading of irradiated fuel assemblies in the core. With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level of 23 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase decay heat load, such as loading a fuel assembly, is a prudent action under this condition.

A.3

If RHR loop requirements are not met, actions shall be initiated and continued in order to satisfy RHR loop requirements. With the unit in MODE 6 and the refueling water level ≥ 23 ft above the top of the reactor vessel flange, corrective actions shall be initiated immediately.

(continued)

BASES

ACTIONS (continued)

A.4

If RHR loop requirements are not met, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This Surveillance demonstrates that the RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator in the control room for monitoring the RHR System.

REFERENCES

1. Watts Bar FSAR, Section 5.5.7, “Residual Heat Removal System.”

B 3.9 REFUELING OPERATIONS

B 3.9.6 Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant, and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchangers where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and the bypass lines. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200 °F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to the boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant will eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Two trains of the RHR System are required to be OPERABLE, and one train in operation, in order to prevent this challenge.

Although the RHR System does not meet a specific criterion of 10 CFR 50.36(c)(2)(ii), it was identified in 10 CFR 50.36(c)(2)(ii) as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification.

BASES (continued)

LCO

In MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, both RHR loops must be OPERABLE.

Additionally, one loop of RHR must be in operation in order to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop consists of an RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path and to determine the low end temperature. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs. Both RHR pumps may be aligned to the Refueling Water Storage Tank (RWST) to support filling the refueling cavity or to perform RHR injection testing. During these modes of operation, the wide range RCS temperature indicators are used to indicate RCS temperature since the RHR temperature elements indicate RWST temperature when RHR pump suction is from the RWST. The flow path for filling the refueling cavity or for performance of RHR cold leg injection testing starts at the RWST and is supplied to the RCS cold legs. During RHR hot leg injection testing with suction from the RWST, the other RHR train must be OPERABLE and in operation with discharge to the RCS cold legs. In this alignment, both RHR trains are OPERABLE provided that the RHR train injecting into the RHR hot legs is capable of being realigned to discharge to the RCS cold legs in the event a failure occurs of the RHR train supplying the cold legs.

APPLICABILITY

Two RHR loops are required to be OPERABLE, and one RHR loop must be in operation in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, to provide decay heat removal. Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, “Reactor Coolant System (RCS),” and Section 3.5, “Emergency Core Cooling Systems (ECCS).” RHR loop requirements in MODE 6 with the water level ≥ 23 ft are located in LCO 3.9.5, “Residual Heat Removal (RHR) and Coolant Circulation - High Water Level.”

BASES (continued)

ACTIONS

A.1 and A.2

If less than the required number of RHR loops are OPERABLE, actions shall be immediately initiated and continued until the RHR loop is restored to OPERABLE status and to operation or until ≥ 23 ft of water level is established above the reactor vessel flange. When the water level is ≥ 23 ft above the reactor vessel flange, the Applicability changes to that of LCO 3.9.5, and only one RHR loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

B.1

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations. Reduced boron concentrations cannot occur by the addition of water with a lower boron concentration than that contained in the RCS, because all of the unborated water sources are isolated.

B.2

If no RHR loop is in operation, actions shall be initiated immediately, and continued, to restore one RHR loop to operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR loops and one operating RHR loop should be accomplished expeditiously.

B.3

If no RHR loop is in operation, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures that dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

This Surveillance demonstrates that one RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. In addition, during operation of the RHR loop with the water level in the vicinity of the reactor vessel nozzles, the RHR pump suction requirements must be met. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator for monitoring the RHR System in the control room.

SR 3.9.6.2

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. Watts Bar FSAR, Section 5.5.7, “Residual Heat Removal System.”

B 3.9 REFUELING OPERATIONS

B 3.9.7 Refueling Cavity Water Level

BASES

BACKGROUND

The movement of irradiated fuel assemblies within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange. During refueling, this maintains sufficient water level in the containment, refueling canal, fuel transfer canal, refueling cavity, and spent fuel pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 5). Sufficient iodine activity would be retained to limit offsite doses from the accident to the limits defined in 10 CFR 50.67 (Ref. 4) and Regulatory Position C.4.4 of Regulatory Guide 1.183 (Ref. 5).

APPLICABLE SAFETY ANALYSES

During movement of irradiated fuel assemblies, the water level in the refueling canal and the refueling cavity is an initial condition design parameter in the analysis of a fuel handling accident in containment. A minimum water level of 23 ft (Regulatory Position 2 of Appendix B to Regulatory Guide 1.183) allows an overall iodine decontamination factor of 200 to be used in the accident analysis. This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 8% of the I-131, 10% of the Kr-85, and 5% of the other noble gases and iodines from the total fission product inventory in accordance with Regulatory Position of Regulatory Guide 1.183.

The fuel handling accident analysis inside containment is described in Reference 1. With a minimum water level of 23 ft in conjunction with a minimum decay time of 100 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses are maintained within allowable limits (Refs. 4 and 5).

Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits, as provided by the guidance of Reference 2.

APPLICABILITY

LCO 3.9.7 is applicable when moving irradiated fuel assemblies within containment. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pool are covered by LCO 3.7.13, "Fuel Storage Pool Water Level."

ACTIONS

A.1

With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of fuel movement shall not preclude completion of movement of a component to a safe position.

A.2

In addition to immediately suspending movement of irradiated fuel, actions to restore refueling cavity water level must be initiated immediately.

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1

Verification of a minimum water level of 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 1).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls of valve positions, which make significant unplanned level changes unlikely.

BASES (continued)

REFERENCES

1. Watts Bar FSAR, Section 15.4.5, “Fuel Handling Accident.”

2. NUREG-0800, “Standard Review Plan,” Section 15.7.4, “Radiological Consequences of Fuel-Handling Accidents,” U.S. Nuclear Regulatory Commission.

3. Title 10, Code of Federal Regulations, Part 20.1201(a), (a)(1), and (2)(2), “Occupational Dose Limits for Adults.”

4. Title 10, Code of Federal Regulations, 10 CFR 50.67, Accident Source Term.”

5. Regulatory Guide 1.183, “Alternate Source Terms for Evaluation Design Basis Accidents at Nuclear Power Reactors,” July 2000.

B 3.9 REFUELING OPERATIONS

B 3.9.8 RESERVED FOR FUTURE ADDITION

B 3.9 REFUELING OPERATIONS

B 3.9.9 Spent Fuel Pool Boron Concentration

BASES

BACKGROUND	The spent fuel storage rack criticality analysis assumes 2000 ppm soluble boron in the fuel pool during a dropped/misplaced fuel assembly event (Ref. 1).
APPLICABLE SAFETY ANALYSES	This requirement ensures the presence of at least 2000 ppm soluble boron in the spent fuel pool water as assumed in the spent fuel rack criticality analysis for dropped/misplaced fuel assembly event. The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The LCO requires that the boron concentration in the spent fuel pool be greater than or equal to 2000 ppm during fuel movement.
APPLICABILITY	This LCO is applicable when the spent fuel pool is flooded and fuel is being moved. Once fuel movement begins, the movement is considered in progress until the configuration of the assemblies in the storage racks is verified to comply with the criticality loading criteria specified in Specification 4.3.1.1.
ACTIONS	A.1 If the spent fuel pool boron concentration does not meet the above requirements, fuel handling in the spent fuel pool must be suspended immediately. This action precludes a fuel handling accident, when conditions are outside those assumed in the accident analysis. Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position.

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.9.1

This SR requires that the spent fuel pool boron concentration be verified greater than or equal to 2000 ppm. This surveillance is to be performed prior to movement of fuel in the spent fuel pool and at least once every 72 hours thereafter during the movement of fuel in the spent fuel pool.

The Frequency of once every 72 hours is a reasonable amount of time to verify the boron concentration of the sample. The Frequency is based on operating experience, which has shown 72 hours to be adequate.

REFERENCES

1. Watts Bar FSAR, Section 9.1.2, “Spent Fuel Storage“ and Section 15, “Accident Analysis.”

B 3.9 REFUELING OPERATIONS

B 3.9.10 Decay Time

BASES

BACKGROUND

Section 15.5.6 of the Watts Bar FSAR (Ref. 1) defines the assumptions of the fuel handling accident radiological analysis, including a minimum decay time for irradiated fuel assemblies prior to movement. This assumption ensures that the inventory of radioactive isotopes is at a level that supports the safety analysis assumptions.

To ensure that irradiated fuel assemblies have decayed for the appropriate period of time, a limitation is established to require the reactor core to be subcritical for a time period at least equivalent to the minimum decay time assumption in the fuel handling analysis prior to allowing irradiated fuel to be moved.

Given that no irradiated fuel assembly will be moved outside of the containment until the minimum decay time requirement is met, this requirement also ensures that any irradiated fuel assemblies that are moved outside of the containment meet the decay time assumption in the radiological analysis of the fuel handling accident.

APPLICABLE SAFETY ANALYSES

The radiological analysis of the fuel handling accident (Ref. 1) assumes a minimum decay time prior to movement of irradiated fuel assemblies. The requirements of LCO 3.3.7, “Control Room Emergency Ventilation System (CREVS) Actuation Instrumentation,” LCO 3.7.10, “Control Room Emergency Ventilation System (CREVS),” LCO 3.7.11, “Control Room Emergency Air Temperature Control System (CREATCS),” and LCO 3.9.7, “Refueling Cavity Water Level,” in conjunction with a minimum decay time of 100 hours prior to irradiated fuel movement ensures that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are within the requirements of 10 CFR 50.67 (Ref. 2) and Regulatory Position C.4.4 of Regulatory Guide 1.183 (Ref. 3).

The decay time satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES (continued)

LCO

A minimum decay time of 100 hours is required prior to moving irradiated fuel assemblies within containment. This preserves an assumption in the fuel handling accident analysis (Ref. 1), and ensures that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits.

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies within the containment, since the potential for a release of fission products exists.

ACTIONS

A.1

When the initial conditions for prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the reactor is subcritical for < 100 hours, movement of irradiated fuel assemblies within containment must be suspended. This action precludes the possibility of a fuel handling accident in containment. This action does not preclude moving a fuel assembly to a safe position.

The immediate Completion Time is consistent with the required times for actions to be performed without delay and in a controlled manner.

SURVEILLANCE REQUIREMENTS

SR 3.9.10.1

This SR verifies that the reactor has been subcritical for at least 100 hours prior to moving irradiated fuel assemblies by confirming the date and time of subcriticality. This ensures that any irradiated fuel assemblies have decayed for at least 100 hours prior to movement. The Frequency of “Prior to movement of irradiated fuel in the containment” is appropriate, because it ensures that the decay time requirement has been met just prior to moving the irradiated fuel.

BASES (continued)

REFERENCES

1. Watts Bar FSAR, Section 15.5.6, “Environmental Consequences of a Postulated Fuel Handling Accident.”

2. Title 10, Code of Federal Regulations, 10 CFR 50.67, “Accident Source Term.”

ENCLOSURE 4

WBN Unit 2 Technical Requirements Manual and Bases

Tennessee Valley Authority

Watts Bar Nuclear Plant Unit 2

Technical Requirements Manual
&
Technical Requirements Manual Bases

TECHNICAL REQUIREMENTS

TECHNICAL REQUIREMENTS

TECHNICAL REQUIREMENTS BASES

TECHNICAL REQUIREMENTS BASES

LIST OF TABLES

LIST OF FIGURES

LIST OF MISCELLANEOUS REPORTS AND PROGRAMS

ACRONYM	TITLE
ABGTS	Auxiliary Building Gas Treatment System
ACRP	Auxiliary Control Room Panel
AFD	Axial Flux Difference
AFW	Auxiliary Feedwater System
ARFS	Air Return Fan System
ARO	All Rods Out
ARV	Atmospheric Relief Valve
ASME	American Society of Mechanical Engineers
BOC	Beginning of Cycle
CCS	Component Cooling Water System
CFR	Code of Federal Regulations
COLR	Core Operating Limits Report
CREVS	Control Room Emergency Ventilation System
CSS	Containment Spray System
CST	Condensate Storage Tank
DNB	Departure from Nucleate Boiling
ECCS	Emergency Core Cooling System
EFPD	Effective Full-Power Days
EGTS	Emergency Gas Treatment System
EOC	End of Cycle
ERCW	Essential Raw Cooling Water
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Features Actuation System
HEPA	High Efficiency Particulate Air
HVAC	Heating, Ventilating, and Air-Conditioning
LCC	Lower Compartment Cooler
LCO	Limiting Condition For Operation
MFIV	Main Feedwater Isolation Valve
MFRV	Main Feedwater Regulation Valve
MSIV	Main Steam Line Isolation Valve
MSSV	Main Steam Safety Valve

(continued)

ACRONYM	TITLE
MTC	Moderator Temperature Coefficient
N/A	Not Applicable
NMS	Neutron Monitoring System
ODCM	Offsite Dose Calculation Manual
PCP	Process Control Program
PDMS	Power Distribution Monitoring System
PIV	Pressure Isolation Valve
PORV	Power-Operated Relief Valve
PTLR	Pressure and Temperature Limits Report
QPTR	Quadrant Power Tilt Ratio
RAOC	Relaxed Axial Offset Control
RCCA	Rod Cluster Control Assembly
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RTP	Rated Thermal Power
RTS	Reactor Trip System
RWST	Refueling Water Storage Tank
SG	Steam Generator
SI	Safety Injection
SL	Safety Limit
SR	Surveillance Requirement
TSR	Technical Surveillance Requirement
UHS	Ultimate Heat Sink

TECHNICAL REQUIREMENTS - LIST OF EFFECTIVE PAGES

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
		1.4-2	0
i	0	1.4-3	0
ii	0	1.4-4	0
iii	0	3.0-1	0
iv	0	3.0-2	0
v	0	3.0-3	0
vi	0	3.0-4	0
vii	0	3.1-1	0
viii	0	3.1-2	0
ix	0	3.1-3	0
x	0	3.1-4	0
xi	0	3.1-5	0
xii	0	3.1-6	0
xiii	0	3.1-7	0
1.1-1	0	3.1-8	0
1.1-2	0	3.1-9	0
1.1-3	0	3.1-10	0
1.1-4	0	3.1-11	0
1.1-5	0	3.1-12	0
1.1-6	0	3.1-13	0
1.2-1	0	3.1-14	0
1.2-2	0	3.3-1	0
1.2-3	0	3.3-2	0
1.3-1	0	3.3-3	0
1.3-2	0	3.3-4	0
1.3-3	0	3.3-5	0
1.3-4	0	3.3-6	0
1.3-5	0	3.3-7	0
1.3-6	0	3.3-8	0
1.3-7	0	3.3-9	0
1.3-8	0	3.3-10	0
1.3-9	0	3.3-11	0
1.3-10	0	3.3-12	0
1.4-1	0	3.3-13	0

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
3.3-14	0	3.7-7	0
3.3-15	0	3.7-8	0
3.3-16	0	3.7-9	0
3.3-17	0	3.7-10	0
3.3-18	0	3.7-11	0
3.3-19	0	3.7-12	0
3.3-20	0	3.7-13	0
3.3-21	0	3.7-14	0
3.3-22	0	3.7-15	0
3.3-23	0	3.7-16	0
3.4-1	0	3.7-17	0
3.4-2	0	3.7-18	0
3.4-3	0	3.7-19	0
3.4-4	0	3.7-20	0
3.4-5	0	3.7-21	0
3.4-6	0	3.7-22	0
3.4-7	0	3.7-23	0
3.4-8	0	3.8-1	0
3.4-9	0	3.8-2	0
3.4-10	0	3.8-3	0
3.4-11	0	3.8-4	0
3.4-12	0	3.8-5	0
3.6-1	0	3.8-6	0
3.6-2	0	3.8-7	0
3.6-3	0	3.8-8	0
3.6-4	0	3.8-9	0
3.6-5	0	3.8-10	0
3.6-6	0	3.8-11	0
3.7-1	0	3.8-12	0
3.7-2	0	3.8-13	0
3.7-3	0	3.8-14	0
3.7-4	0	3.8-15	0
3.7-5	0	3.8-16	0
3.7-6	0	3.8-17	0

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
3.8-18	0	B 3.1-10	0
3.8-19	0	B 3.1-11	0
3.8-20	0	B 3.1-12	0
3.9-1	0	B 3.1-13	0
3.9-2	0	B 3.1-14	0
3.9-3	0	B 3.1-15	0
3.9-4	0	B 3.1-16	0
3.9-5	0	B 3.1-17	0
5.0-1	0	B 3.1-18	0
		B 3.1-19	0
B 3.0-1	0	B 3.1-20	0
B 3.0-2	0	B 3.1-21	0
B 3.0-3	0	B 3.1-22	0
B 3.0-4	0	B 3.1-23	0
B 3.0-5	0	B 3.1-24	0
B 3.0-6	0	B 3.1-25	0
B 3.0-7	0	B 3.1-26	0
B 3.0-8	0	B 3.3-1	0
B 3.0-9	0	B 3.3-2	0
B 3.0-10	0	B 3.3-3	0
B 3.0-11	0	B 3.3-4	0
B 3.0-12	0	B 3.3-5	0
B 3.0-13	0	B 3.3-6	0
B 3.0-14	0	B 3.3-7	0
B 3.0-15	0	B 3.3-8	0
B 3.1-1	0	B 3.3-9	0
B 3.1-2	0	B 3.3-10	0
B 3.1-3	0	B 3.3-11	0
B 3.1-4	0	B 3.3-12	0
B 3.1-5	0	B 3.3-13	0
B 3.1-6	0	B 3.3-14	0
B 3.1-7	0	B 3.3-15	0
B 3.1-8	0	B 3.3-16	0
B 3.1-9	0	B 3.3-17	0

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
B 3.3-18	0	B 3.6-11	0
B 3.3-19	0	B 3.6-12	0
B 3.3-20	0	B 3.7-1	0
B 3.3-21	0	B 3.7-2	0
B 3.3-22	0	B 3.7-3	0
B 3.3-23	0	B 3.7-4	0
B 3.3-24	0	B 3.7-5	0
B 3.3-25	0	B 3.7-6	0
B 3.3-26	0	B 3.7-7	0
B 3.4-1	0	B 3.7-8	0
B 3.4-2	0	B 3.7-9	0
B 3.4-3	0	B 3.7-10	0
B 3.4-4	0	B 3.7-11	0
B 3.4-5	0	B 3.7-12	0
B 3.4-6	0	B 3.7-13	0
B 3.4-7	0	B 3.7-14	0
B 3.4-8	0	B 3.7-15	0
B 3.4-9	0	B 3.7-16	0
B 3.4-10	0	B 3.7-17	0
B 3.4-11	0	B 3.7-18	0
B 3.4-12	0	B 3.7-19	0
B 3.4-13	0	B 3.7-20	0
B 3.4-14	0	B 3.7-21	0
B 3.4-15	0	B 3.7-22	0
B 3.6-1	0	B 3.8-1	0
B 3.6-2	0	B 3.8-2	0
B 3.6-3	0	B 3.8-3	0
B 3.6-4	0	B 3.8-4	0
B 3.6-5	0	B 3.8-5	0
B 3.6-6	0	B 3.8-6	0
B 3.6-7	0	B 3.8-7	0
B 3.6-8	0	B 3.8-8	0
B 3.6-9	0	B 3.8-9	0
B 3.6-10	0	B 3.8-10	0

PAGE NUMBER	AMENDMENT NUMBER	PAGE NUMBER	AMENDMENT NUMBER
B 3.8-11	0		
B 3.8-12	0		
B 3.8-13	0		
B 3.8-14	0		
B 3.8-15	0		
B 3.8-16	0		
B 3.8-17	0		
B 3.8-18	0		
B 3.8-19	0		
B 3.9-1	0		
B 3.9-2	0		
B 3.9-3	0		
B 3.9-4	0		
B 3.9-5	0		
B 3.9-6	0		
B 3.9-7	0		
B 3.9-8	0		

1.0 USE AND APPLICATION

1.1 Definitions

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

Term	Definition
ACTIONS	ACTIONS shall be that part of a Requirement that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel so that it responds within the required range and accuracy to known input. The CHANNEL CALIBRATION shall encompass the entire channel, including the required sensor, alarm, interlock, display, and trip functions. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION shall include an inplace cross calibration that compares the other sensing elements with the recently installed sensing element. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping calibrations or total channel steps so that the entire channel is calibrated.
CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.

1.1 Definitions (continued)

Term	Definition
CHANNEL OPERATIONAL TEST (COT)	A COT shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify the OPERABILITY of required alarm, interlock, display, and trip functions. The COT shall include adjustments, as necessary, of the required alarm, interlock, and trip setpoints so that the setpoints are within the required range and accuracy.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or other reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
ENGINEERED SAFETY FEATURE (ESF) RESPONSE TIME	The ESF RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its ESF actuation setpoint at the channel sensor until the ESF 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. In lieu of measurement, response time may be verified for selected components provided that the components and the methodology for verification have been previously reviewed and approved by the NRC.
LEAKAGE	LEAKAGE shall be: a. <u>Identified LEAKAGE</u> 1. LEAKAGE, such as that from pump seals or valve packing (except reactor coolant pump (RCP) seal water injection or leakoff), that is captured and conducted to collection systems or a sump or collecting tank;

(continued)

1.1 Definitions

Term	Definition
LEAKAGE (continued)	2. LEAKAGE into the containment 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; or 3. Reactor Coolant System (RCS) LEAKAGE through a steam generator (SG) tube to the Secondary System; b. Unidentified LEAKAGE All LEAKAGE (except RCP seal water injection or leakoff) that is not identified LEAKAGE; c. Pressure Boundary LEAKAGE LEAKAGE (except SG tube LEAKAGE) through a non-isolable fault in an RCS component body, pipe wall, or vessel wall.
MODE	A MODE shall correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE – OPERABILITY	A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average lower excore detector calibrated outputs, whichever is greater.

1.1 Definitions (continued)

Term	Definition
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3411 MWt.
REACTOR TRIP SYSTEM (RTS) RESPONSE TIME	The RTS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RTS trip setpoint at the channel sensor until loss of stationary gripper coil voltage. 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. In lieu of measurement, response time may be verified for selected components provided that the components and the methodology for verification have been previously reviewed and approved by the NRC.
SHUTDOWN MARGIN (SDM)	SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming: a. All rod cluster control assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. With any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM; and b. In MODES 1 and 2, the fuel and moderator temperatures are changed to the nominal zero power design level.
STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

1.1 Definitions (continued)

Term	Definition
TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT)	TADOT shall consist of operating the trip actuating device and verifying OPERABILITY of required alarm, interlock, display, and trip functions. The TADOT shall include adjustment, as necessary, of the trip actuating device so that it actuates at the required setpoint within the required accuracy.

Table 1.1-1 (page 1 of 1)
MODES

MODE	TITLE	REACTIVITY CONDITION (k_{eff})	% RATED THERMAL POWER [a]	AVERAGE REACTOR COOLANT TEMPERATURE (°F)
1	Power Operation	≥ 0.99	> 5	NA
2	Startup	≥ 0.99	≤ 5	NA
3	Hot Standby	< 0.99	NA	≥ 350
4	Hot Shutdown [b]	< 0.99	NA	350 > T_{avg} > 200
5	Cold Shutdown [b]	< 0.99	NA	≤ 200
6	Refueling [c]	NA	NA	NA

(a) Excluding decay heat.

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

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

1.0 USE AND APPLICATION

1.2 Logical Connectors

PURPOSE	The purpose of this section is to explain the meaning of logical connectors. Logical connectors are used in Technical Requirements (TRs) to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, Surveillances, and Frequencies. The only logical connectors that appear in TRs are AND and OR. The physical arrangement of these connectors constitutes logical conventions with specific meanings.
BACKGROUND	Several levels of logic may be used to state Required Actions. These levels are identified by the placement (or nesting) of the logical connectors and by the number assigned to each Required Action. The first level of logic is identified by the first digit of the number assigned to a Required Action and the placement of the logical connector in the first level of nesting (i.e., left justified with the number of the Required Action). The successive levels of logic are identified by additional digits of the Required Action number and by successive indentations of the logical connectors. When logical connectors are used to state a Condition, Completion Time, Surveillance, or Frequency, only the first level of logic is used, and the logical connector is left justified with the statement of the Condition, Completion Time, Surveillance, or Frequency.

1.2 Logical Connectors (Continued)

EXAMPLES

The following examples illustrate the use of logical connectors.

EXAMPLE 1.2-1

ACTIONS

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

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

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-2

ACTIONS

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

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

1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE	The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.
BACKGROUND	Technical Requirements (TRs) specify minimum requirements for ensuring safe operation of the unit. The ACTIONS associated with a TR state Conditions that typically describe the ways in which the requirements of the TR can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).
DESCRIPTION	The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the unit is in a MODE or specified condition stated in the Applicability of the TR. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the unit is not within the TR Applicability. If situations are discovered that require entry into more than one Condition at a time within a single TR (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition. Once a Condition has been entered, subsequent trains, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will <u>not</u> result in separate entry into the Condition, unless specifically stated. The Required Actions of the Condition continue to apply to each additional failure, with Completion Times based on initial entry into the Condition.

(continued)

1.3 Completion Times

DESCRIPTION (continued)

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

a. Must exist concurrent with the first inoperability; and

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

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

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

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

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

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

1.3 Completion Times (continued)

EXAMPLES

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

EXAMPLE 1.3-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

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

The Required Actions of Condition B are to be in MODE 3 within 6 hours AND in MODE 5 within 36 hours. A total of 6 hours is allowed for reaching MODE 3 and a total of 36 hours (not 42 hours) is allowed for reaching MODE 5 from the time that Condition B was entered. If MODE 3 is reached within 3 hours, the time allowed for reaching MODE 5 is the next 33 hours because the total time allowed for reaching MODE 5 is 36 hours.

If Condition B is entered while in MODE 3, the time allowed for reaching MODE 5 is the next 36 hours.

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pump inoperable.	A.1 Restore pump to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

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

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

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

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

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-2 (continued)

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

EXAMPLE 1.3-3

ACTIONS

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

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-3 (continued)

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

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

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

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

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

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

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

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-5

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

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

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

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.

(continued)

1.3 Completion Times (continued)

EXAMPLE 1.3-6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One channel inoperable.	A.1 Perform TSR 3.x.x.x. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

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

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

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable	A.1 Verify affected subsystem isolated.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore subsystem to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

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

If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour or any subsequent 8 hour interval from the previous performance (plus the extension allowed by TSR 3.0.2), Condition B is entered. The Completion Time clock for Condition A does not stop after Condition B is entered, but continues from the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

IMMEDIATE COMPLETION TIME

When "Immediately" is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner.

1.0 USE AND APPLICATION

1.4 Frequency

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

DESCRIPTION

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

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

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

1.4 Frequency (Continued)

EXAMPLES

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

EXAMPLE 1.4-1

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of TSR most often encountered in the TRs. The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the interval specified in the Frequency is allowed by TSR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the TSR is not required to be met per TSR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the TR). If the interval specified by TSR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the TR, and the performance of the Surveillance is not otherwise modified (refer to Example 1.4-3), then TSR 3.0.3 becomes applicable.

If the interval as specified by TSR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the TR for which performance of the TSR is required, the Surveillance must be performed within the Frequency requirements of TSR 3.0.2 prior to entry into the MODE or other specified condition. Failure to do so would result in a violation of TSR 3.0.4.

(continued)

EXAMPLES (continued)

EXAMPLE 1.4-2

TECHNICAL SURVEILLANCE REQUIREMENTS

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

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

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the extension allowed by TSR 3.0.2. "Thereafter" indicates future performances must be established per TSR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

(continued)

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-3

TECHNICAL SURVEILLANCE REQUIREMENTS

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

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

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

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

3.0 TECHNICAL REQUIREMENT (TR) APPLICABILITY

TR 3.0.1

TRs shall be met during the MODES or other specified conditions in the Applicability, except as provided in TR 3.0.2.

TR 3.0.2

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

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

TR 3.0.3

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

a. MODE 3 within 7 hours;

b. MODE 4 within 13 hours; and

c. MODE 5 within 37 hours.

Exceptions to this Requirement are stated in the individual Requirements.

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

TR 3.0.3 is only applicable in MODES 1, 2, 3, and 4.

TR 3.0.4

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

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

(continued)

3.0 TECHNICAL REQUIREMENT (TR) APPLICABILITY

TR 3.0.4 (continued)

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

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

This TR 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.

TR 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 TR 3.0.2 for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY.

TR 3.0.6

When a supported system TR or LCO is not met solely due to a support system TR or LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system TR or LCO ACTIONS are required to be entered. This is an exception to TR 3.0.2 and LCO 3.0.2 for the supported system. In this event, additional evaluations and limitations may be required in accordance with Technical Specification 5.7.2.18, "Safety Function Determination Program (SFDP)." If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the TR or LCO in which the loss of safety function exists are required to be entered.

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

3.0 TECHNICAL SURVEILLANCE REQUIREMENT (TSR) APPLICABILITY

TSR 3.0.1

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

TSR 3.0.2

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

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

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

Exceptions to this Requirement are stated in the individual Requirements.

TSR 3.0.3

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

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

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

3.0 TECHNICAL SURVEILLANCE REQUIREMENT (TSR) APPLICABILITY (continued)

TSR 3.0.4

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

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

TR 3.1 REACTIVITY CONTROL SYSTEMS

TR 3.1.1 Boration Systems Flow Paths, Shutdown

TR 3.1.1 One of the following boron injection flow paths shall be OPERABLE and capable of being powered from an OPERABLE emergency power source:

a. A flow path from an OPERABLE boric acid storage system, through the boric acid transfer pump, through a charging pump to the Reactor Coolant System (RCS), or

b. A flow path from an OPERABLE Refueling Water Storage Tank (RWST) through a charging pump to the RCS.

APPLICABILITY: MODES 4, 5, and 6.

----------NOTE----------
For MODE 4, Technical Specification LCO 3.0.4.b is not applicable to Emergency Core Cooling System high head (centrifugal charging) subsystem.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Boration Systems flow path OPERABILITY requirements not met. OR Boration Systems flow path not capable of being powered by an OPERABLE emergency power source.	A.1 Suspend CORE ALTERATIONS. AND A.2 Suspend positive reactivity additions.	Immediately Immediately

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.1.1.1	----------NOTE---------- Only required if the flow path from the boric acid storage tanks (BATs) is required OPERABLE. ---------- Verify temperature of the areas containing flowpath components from the BATs is ≥ 63°F.	12 hours
TSR 3.1.1.2	Verify, for the required OPERABLE flowpath, that each manual, power operated, or automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days

TR 3.1 REACTIVITY CONTROL SYSTEMS

TR 3.1.2 Boration Systems Flow Paths, Operating

TR 3.1.2 Two of the following three boron injection flow paths shall be OPERABLE:

a. One flow path from the boric acid tanks, through a boric acid transfer pump, through a charging pump to the Reactor Coolant System (RCS).

b. Two flow paths from the Refueling Water Storage Tank (RWST), through charging pumps to the RCS.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required flow path inoperable.	A.1	Restore required flow path to OPERABLE status.	72 hours
	OR		
	A.2.1	Be in MODE 3.	78 hours
	AND		
	A.2.2	Borate to a SDM equivalent to ≥ 1% $\Delta k/k$ at 200°F.	78 hours
	AND		
	A.2.3	Restore required path to OPERABLE status.	246 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 4.	6 hours

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.1.2.1	----------NOTE---------- Only required if the flow path from the boric acid tanks is required OPERABLE. ---------- Verify temperature of the areas containing portions of the required flow path from the boric acid tanks is ≥ 63°F.	12 hours
TSR 3.1.2.2	Verify, for the required OPERABLE flow paths, each manual, power operated or automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days
TSR 3.1.2.3	Demonstrate that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal.	18 months
TSR 3.1.2.4	Verify that the flow path from the boric acid tanks delivers ≥ 35 gpm to the RCS.	18 months

TR 3.1 REACTIVITY CONTROL SYSTEMS

TR 3.1.3 Charging Pump, Shutdown

TR 3.1.3 One charging pump in the boron injection flow path required by TR 3.1.1 shall be OPERABLE and capable of being powered from an OPERABLE emergency power source.

APPLICABILITY: MODES 4, 5, and 6.

----------NOTE----------
For MODE 4, Technical Specification LCO 3.0.4.b is not applicable to ECCS high head (centrifugal charging) subsystem.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required charging pump inoperable.	A.1 Suspend CORE ALTERATIONS.	Immediately
OR	AND	
Required charging pump not capable of being powered by an OPERABLE emergency power source.	A.2 Suspend positive reactivity additions.	Immediately

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.1.3.1	Verify required charging pump's developed head at the test flow point is ≥ the required developed head.	In accordance with Inservice Testing Program

TR 3.1 REACTIVITY CONTROL SYSTEMS

TR 3.1.4 Charging Pumps, Operating

TR 3.1.4 Two charging pumps shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required charging pump inoperable.	A.1 Restore required charging pump to OPERABLE status.	72 hours
	OR	
	A.2.1 Be in MODE 3.	78 hours
	AND	
	A.2.2 Borate to a SDM equivalent to ≥ 1% $\Delta k/k$ at 200°F.	78 hours
	AND	
	A.2.3 Restore required charging pump to OPERABLE status.	246 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 4.	6 hours

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.1.4.1	Verify required charging pump's developed head at the test flow point is ≥ the required developed head.	In accordance with Inservice Testing Program

TR 3.1 REACTIVITY CONTROL SYSTEMS

TR 3.1.5 Borated Water Sources, Shutdown

TR 3.1.5 One of the following borated water sources shall be OPERABLE as required by TR 3.1.1:

a. A Boric Acid Storage System, or

b. The Refueling Water Storage Tank (RWST).

APPLICABILITY: MODES 4, 5, and 6.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Required borated water source inoperable.	A.1	Suspend CORE ALTERATIONS.	Immediately
	AND		
	A.2	Suspend positive reactivity additions.	Immediately

TECHNICAL SURVEILLANCE REQUIREMENTS

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

1. TSR 3.1.5.1, TSR 3.1.5.2 and TSR 3.1.5.3 are only required to be met if the RWST is the required borated water source.

2. TSR 3.1.5.4, TSR 3.1.5.5 and TSR 3.1.5.6 are only required to be met if the Boric Acid Storage System is the required borated water source.

SURVEILLANCE		FREQUENCY
TSR 3.1.5.1	----------NOTE---------- Only required when ambient air temperature is < 60°F. ---------- Verify RWST solution temperature is ≥ 60°F.	24 hours
TSR 3.1.5.2	Verify RWST boron concentration is ≥ 3,100 ppm.	7 days
TSR 3.1.5.3	Verify RWST borated water volume is ≥ 62,900 gallons.	7 days
TSR 3.1.5.4	Verify Boric Acid Tank (BAT) solution temperature is ≥ 63°F.	24 hours
TSR 3.1.5.5	Verify BAT boron concentration is ≥ 6,120 ppm and ≤ 6,990 ppm.	7 days
TSR 3.1.5.6	Verify BAT borated water volume is ≥ 5,300 gallons.	7 days

TR 3.1 REACTIVITY CONTROL SYSTEMS

TR 3.1.6 Borated Water Sources, Operating

TR 3.1.6 The following borated water sources shall be OPERABLE as required by TR 3.1.2:

a. A Boric Acid Storage System, and

b. The Refueling Water Storage Tank (RWST).

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Required Boric Acid Storage System inoperable.	A.1	Restore Boric Acid Storage System to OPERABLE status.	72 hours
	OR		
	A.2.1	Be in MODE 3.	78 hours
	AND		
	A.2.2	Borate to a SDM equivalent to ≥ 1% Δk/k at 200°F.	78 hours
	AND		
	A.2.3	Restore Boric Acid Storage System to OPERABLE status.	246 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 4.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. RWST boron concentration not within limits. <u>OR</u> RWST borated water temperature not within limits.	C.1	Restore RWST to OPERABLE status.	8 hours
D. RWST inoperable for reasons other than Condition C.	D.1	Restore RWST to OPERABLE status.	1 hour
E. Required Action and associated Completion Time of Condition C or D not met.	E.1	Be in MODE 3	6 hours
	<u>AND</u>		
	E.2	Be in MODE 4 with one or more RCS cold leg temperatures ≤ 310°F.	12 hours

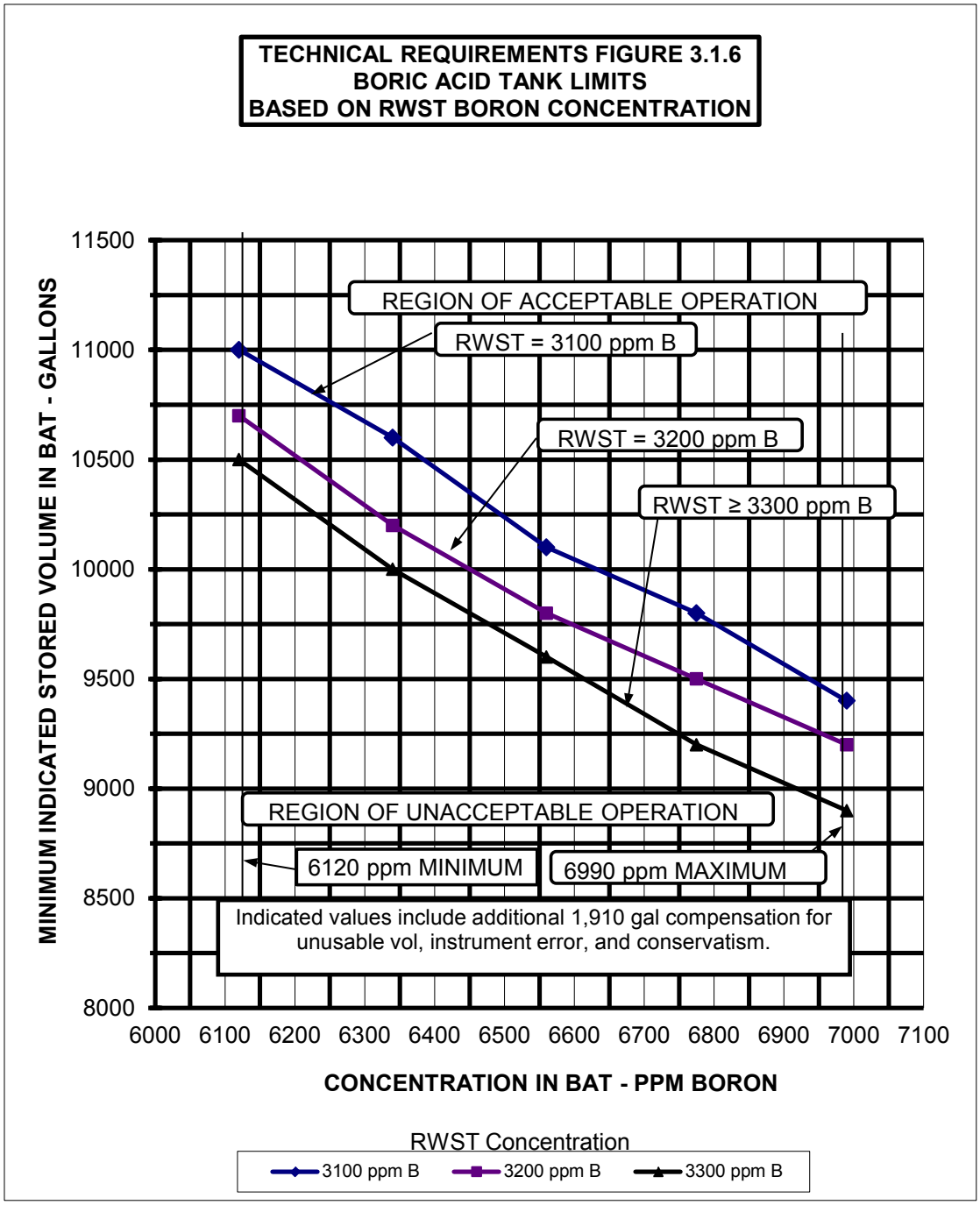
TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.1.6.1	----------NOTE---------- Only required to be performed when outside air temperature is < 60°F or >105°F. ---------- Verify RWST solution temperature is ≥ 60°F and ≤ 105°F.	24 hours
TSR 3.1.6.2	Verify RWST boron concentration is ≥ 3,100 ppm and ≤ 3,300 ppm.	7 days

(continued)

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TSR 3.1.6.3	Verifiy RWST borated water volume is ≥ 370,000 gallons.	7 days
TSR 3.1.6.4	----------NOTE---------- Only required if the BAT is required OPERABLE. ---------- Verify Boric Acid Tank (BAT) solution temperature is ≥ 63°F.	24 hours
TSR 3.1.6.5	----------NOTE---------- Only required if the BAT is required OPERABLE. ---------- Verify BAT boron concentration is in accordance with Figure 3.1.6.	7 days
TSR 3.1.6.6	----------NOTE---------- Only required if the BAT is required OPERABLE. ---------- Verify BAT borated water volume is in accordance with Figure 3.1.6.	7 days


TECHNICAL REQUIREMENTS FIGURE 3.1.6
BORIC ACID TANK LIMITS
BASED ON RWST BORON CONCENTRATION
MINIMUM INDICATED STORED VOLUME IN BAT - GALLONS
11500
11000
10500
10000
9500
9000
8500
8000
6000 6100 6200 6300 6400 6500 6600 6700 6800 6900 7000 7100
CONCENTRATION IN BAT - PPM BORON
REGION OF ACCEPTABLE OPERATION
RWST = 3100 ppm B
RWST = 3200 ppm B
RWST ≥ 3300 ppm B
REGION OF UNACCEPTABLE OPERATION
6120 ppm MINIMUM
6990 ppm MAXIMUM
Indicated values include additional 1,910 gal compensation for unusable vol, instrument error, and conservatism.
RWST Concentration
3100 ppm B
3200 ppm B
3300 ppm B

TR 3.1 REACTIVITY CONTROL SYSTEMS

TR 3.1.7 Position Indication System, Shutdown

TR 3.1.7 The group demand position indicators shall be OPERABLE and capable of determining within ± 2 steps the demand position for each shutdown or control rod that is not fully inserted.

APPLICABILITY: MODES 3, 4, and 5, when the reactor trip breakers are closed.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more group demand position indicators inoperable.	A.1 Open reactor trip breakers.	Immediately

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.1.7.1	Determine that each group demand position indicator is OPERABLE by movement of the associated shutdown or control rod 10 steps in any one direction.	Within 4 hours after closing the reactor trip breakers if not completed within previous 31 days. <u>AND</u> 31 days thereafter

TR 3.3 INSTRUMENTATION

TR 3.3.1 Reactor Trip System (RTS) Instrumentation

TR 3.3.1 The RTS instrumentation channels of Technical Specification (TS) 3.3.1, Table 3.3.1-1 shall be OPERABLE with RESPONSE TIMES as shown in Table 3.3.1-1 of this document.

APPLICABILITY: As shown in TS 3.3.1, Table 3.3.1-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refer to TS 3.3.1, Table 3.3.1-1.	A.1 Refer to TS 3.3.1, Table 3.3.1-1.	Refer to TS 3.3.1, Table 3.3.1-1.

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.1.1	Verify RTS RESPONSE TIME of each reactor trip function is within the limits of Table 3.3.1-1.	18 months on a STAGGERED TEST BASIS

Table 3.3.1-1 (Page 1 of 2)

Reactor Trip System Instrumentation Response Times

FUNCTIONAL UNIT		RESPONSE TIME
1.	Manual Reactor Trip	N/A
2.	Power Range, Neutron Flux	
	a. High	≤ 0.5 second [1]
	b. Low	≤ 0.5 second [1]
3.	Power Range, Neutron Flux	
	a. High Positive Rate	N/A
	b. High Negative Rate	Deleted
4.	Intermediate Range, Neutron Flux	N/A
5.	Source Range, Neutron Flux	≤ 0.5 seconds [1]
6.	Overtemperature ΔT	≤ 8 seconds [1]
7.	Overpower ΔT	≤ 8 seconds [1]
8.	Pressurizer Pressure	
	a. Low	≤ 2 seconds
	b. High	≤ 2 seconds
9.	Pressurizer Water Level--High	N/A

(continued)

[1] Neutron detectors are exempt from response time testing. Response time of the neutron flux signal portion of the channel shall be measured from the detector output or input of first electronic component in channel.

Table 3.3.1-1 (Page 2 of 2)

Reactor Trip System Instrumentation Response Times

FUNCTIONAL UNIT		RESPONSE TIME
10.	Reactor Coolant Flow - Low	≤ 1.2 seconds
11.	Undervoltage-Reactor Coolant Pumps	≤ 1.5 seconds (2)
12.	Underfrequency-Reactor Coolant Pumps	≤ 0.6 second (3)
13.	Steam Generator Water Level-Low-Low	≤ 2 seconds (4)
14.	Turbine Trip	
	a. Low Fluid Oil Pressure	N/A
	b. Turbine Stop Valve Closure	N/A
15.	Safety Injection Input from ESF	N/A
16.	Reactor Trip System Interlocks	N/A
17.	Reactor Trip Breakers	N/A
18.	Reactor Trip Breaker UV and ST	N/A
19.	Automatic Trip and Interlock Logic	N/A

(2) Includes sensor delay time, adjustable time delay, logic and breaker trip times, gripper release (150 msec.) and EMF decay time (250 msec.).

(3) Includes sensor delay time, adjustable time delay, logic and breaker trip times and gripper release time (150 msec.).

(4) With Trip Time Delay (TTD) = 0 seconds.

TR 3.3 INSTRUMENTATION

TR 3.3.2 Engineered Safety Features Actuation System (ESFAS) Instrumentation

TR 3.3.2 The ESFAS instrumentation channels and interlocks as shown in Technical Specification (TS) 3.3.2, Table 3.3.2-1; TS 3.3.5, LCO 3.3.5; TS 3.3.6, Table 3.3.6-1; and TS 3.6.9 shall be OPERABLE with RESPONSE TIMES as shown in Table 3.3.2-1 of this document.

APPLICABILITY: As shown in TS 3.3.2, Table 3.3.2-1; TS 3.3.5 Applicability; TS 3.3.6 Applicability; and TS 3.6.9 Applicability.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refer to TS 3.3.2, Table 3.3.2-1; TS 3.3.5 ACTIONS; TS 3.3.6 ACTIONS; and TS 3.6.9 ACTIONS.	A.1 Refer to TS 3.3.2, Table 3.3.2-1; TS 3.3.5 ACTIONS; TS 3.3.6 ACTIONS; and TS 3.6.9 ACTIONS.	Refer to TS 3.3.2, Table 3.3.2-1; TS 3.3.5 ACTIONS; TS 3.3.6 ACTIONS; and TS 3.6.9 ACTIONS.

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.2.1	Verify ESFAS RESPONSE TIME of each ESFAS function is within the limits of Table 3.3.2-1.	18 months on a STAGGERED TEST BASIS

Table 3.3.2-1 (Page 1 of 6)

Engineered Safety Features Actuation System Response Times

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Manual Initiation	
a. Safety Injection (ECCS)	N.A.
b. Containment Spray	N.A.
c. Phase "A" Isolation	N.A.
d. Phase "B" Isolation	N.A.
e. Containment Ventilation Isolation	N.A.
f. Steam Line Isolation	N.A.
g. Feedwater Isolation	N.A.
h. Auxiliary Feedwater	N.A.
i. Essential Raw Cooling Water	N.A.
j. CREVS Actuation	N.A.
k. Containment Air Return Fan	N.A.
l. Component Cooling System	N.A.
m. Start Diesel Generators	N.A.
n. Reactor Trip	N.A.
2. Containment Pressure - High	
a. Safety Injection (ECCS)	≤ 27 (4) / 32 (14) / 37 (5)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 8 (3)
3) Containment Isolation - Phase “A” (6)	≤ 12 (2) / 22 (1)
4) Containment Ventilation Isolation	≤ 6.0 (2) (11)
5) Auxiliary Feedwater Pumps	≤ 60 (10)
6) Essential Raw Cooling Water	≤ 47 (2) / 57 (1)
7) CREVS Actuation	N.A.

(continued)

Table 3.3.2-1 (Page 2 of 6)

Engineered Safety Features Actuation System Response Times

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
2. Containment Pressure – High (continued)	
8) Component Cooling System	≤ 50 (2) /60 (1)
9) Start Diesel Generators	≤ 12 (12)
3. Pressurizer Pressure - Low	
a. Safety Injection (ECCS)	≤ 27 (4) / 32 (14) / 37 (5)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 8 (3)
3) Containment Isolation - Phase “A” (6)	≤ 12 (2) / 22 (1)
4) Containment Ventilation Isolation	≤ 6.0 (2) (11)
5) Auxiliary Feedwater Pumps	≤ 60 (10)
6) Essential Raw Cooling Water	≤ 47 (2) / 57 (1)
7) CREVS Actuation	N.A.
8) Component Cooling System	≤ 50 (2) / 60 (1)
9) Start Diesel Generators	≤ 12 (12)
4. Steam Line Pressure Negative Rate - High	
a. Steam Line Isolation	≤ 8
5. Steam Line Pressure – Low	
a. Safety Injection (ECCS)	≤ 27 (4) / 32 (14) / 37 (5)
1) Reactor Trip (from SI)	≤ 2
2) Feedwater Isolation	≤ 8 (3)
3) Containment Isolation-Phase "A"(6)	≤ 12(2) / 22(1)
	(continued)

Table 3.3.2-1 (Page 3 of 6)

Engineered Safety Features Actuation System Response Times

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
5. Steam Line Pressure – Low (continued)	
4) Containment Ventilation Isolation	≤ 6.0 (2) (11)
5) Auxiliary Feedwater Pumps	≤ 60 (10)
6) Essential Raw Cooling Water	≤ 47 (2) / 57 (1)
7) CREVS Actuation	N.A.
8) Component Cooling System	≤ 50 (2) / 60 (1)
9) Start Diesel Generators	≤ 12 (12)
b. Steam Line Isolation	≤ 8
6. Containment Pressure - High – High	
a. Containment Spray	≤ 234 (13)
b. Containment Isolation-Phase "B"	≤ 68 (2) / 78 (1)
c. Steam Line Isolation	≤ 8
d. Containment Air Return Fans	480 ≤ RT ≤ 600
7. Steam Generator Water Level - High – High	
a. Turbine Trip	≤ 2.5
b. Feedwater Isolation	≤ 8 (3)
8. Steam Generator Water Level - Low – Low	
a. Motor-driven Auxiliary Feedwater Pumps	≤ 60 (7)
b. Turbine-driven Auxiliary Feedwater Pumps	≤ 60 (8)
9. NOT USED	

(continued)

Table 3.3.2-1 (Page 4 of 6)

Engineered Safety Features Actuation System Response Times

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
10. RWST Level-Low Coincident with Containment Sump Level - High and Safety Injection	
Automatic Switchover to Containment Sump	≤ 250
11. Loss-of-Offsite Power	
Auxiliary Feedwater Pumps	≤ 60
12. Trip of All Main Feedwater Pumps	
Auxiliary Feedwater Pumps	≤ 60
13. Auxiliary Feedwater Pump Suction Transfer on Suction Pressure – Low	
a. Motor-driven Auxiliary Feedwater Pumps	≤ 47
b. Turbine-driven Auxiliary Feedwater Pumps	≤ 42
14. Loss of Voltage/Degraded Voltage	
6.9 kV Shutdown Board	≤ 12 (9)
15. MSV Vault Room Water Level – High	
a. North MSV Vault Room	≤ 8.5 (15)
b. South MSV Vault Room	≤ 8.5 (15)

Table 3.3.2-1 (Page 5 of 6)

Engineered Safety Features Actuation System Response Times

TABLE NOTATIONS

(1) Diesel generator starting and sequence loading delays included.

(2) Diesel generator starting and sequence loading delay not included. Offsite power available.

(3) Air operated valves.

(4) Offsite power available - diesel generator starting and sequence loading delays not included. Response time limit includes the opening of valves to establish flowpath and bringing the pumps to full speed. The additional sequential transfer of CCP suction from the VCT to the RWST (RWST valves open, then the VCT valves close) is included.

(5) Diesel generator starting and sequence loading delays included. Response time limit includes the opening of valves to establish flow path and bringing the pumps up to full speed. The additional sequential transfer of suction from the VCT to the RWST (RWST valves open, then VCT valves close) is included.

(6) The following equipment are exceptions to the response time shown in the table and will have the following response times for the initiating signals and functions:

A. Fire Protection CIVs	≤ 22 (2) / 32 (1)
B. Ice Condenser CIVs	≤ 32
C. Excess Letdown Hx Supply CIV	≤ 68 (2)/ 78 (1)
D. EGTS Fans	≤ 20 (2) / 30 (1)
E. Required for EGTS OPERABILITY	
1. Fire Protection Secondary CIVs	≤ 20 (2) / 30 (1)
2. Secondary Containment Purge Isolation Valves	≤ 12.7 (2) / 22.7 (1)
F. Steam Generator Blowdown CIVs	≤ 17 (2) / 27 (1)

(7) On 2/3 any steam generator and Trip Time Delay = 0 seconds.

(8) On 2/3 in 2/4 steam generators and Trip Time Delay = 0 seconds.

(continued)

Table 3.3.2-1 (Page 6 of 6)

Engineered Safety Features Actuation System Response Times

TABLE NOTATIONS

(9) The response time is measured from the time the 6.9 kV shutdown boards voltage exceeds the Setpoint until the time full voltage is returned for the loss of voltage sensors; or from the time the degraded voltage timers generate a signal to trip the feeder breakers and shed loads until the time full voltage is returned for the degraded voltage sensors.

(10) The Response Time for motor-driven AFW pumps includes the diesel generator starting and sequence loading delays. The Response Time for (steam) turbine driven AFW pumps does not include diesel generator starting and sequence loading delays.

(11) Containment purge valves only. Containment radiation monitor valves have a response time of 6.5 seconds.

(12) Diesel generator start time includes a reactor trip response time of 2 seconds.

(13) Includes diesel generator starting, containment spray pump sequence loading-delay/breaker closure, plus stroke time of 2-FCV-72-2 and 2-FCV-72-39.*

* The containment integrity analysis of record was performed using 221 seconds for initiation of spray. However, Westinghouse document WAT-D-11264 has evaluated the initiation of spray at 234 seconds with the conclusion that the increase will have no effect on the results or conclusions of the Watts Bar LOCA and MSLB containment integrity analysis.

(14) Diesel generator starting and sequence loading delays included. Response time limit includes the opening of valves to establish flowpath and bring pumps to full speed. The additional sequential transfer of ECCS pump suction from the VCT to the RWST (RWST valves open) is included.

(15) Feedwater Isolation Valve (motor) and Feedwater Regulating Valve (air operated) response time includes an ESFAS signal response time of 2 seconds.

TR 3.3 INSTRUMENTATION

TR 3.3.3 RESERVED FOR FUTURE ADDITION

TR 3.3 INSTRUMENTATION

TR 3.3.4 Seismic Instrumentation

TR 3.3.4 The seismic monitoring instrumentation shown in Table 3.3.4-1 shall be OPERABLE.

APPLICABILITY: At all times.

----------NOTE----------
TR 3.0.3 is not applicable.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more seismic monitoring instruments in Panel 0-R-113 or foundation instrument 0-XT-52-75A in the Containment annulus inoperable for > 30 days, <u>OR</u> One or more remaining seismic monitoring instruments inoperable for > 60 days.	A.1 Document in accordance with the Corrective Action Program.	In accordance with the Corrective Action Program.

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. ----------NOTE---------- All Required Actions must be completed whenever this Condition is entered. ----------	B.1	Document in accordance with the Corrective Action Program.	In accordance with the Corrective Action Program.
	AND		
One or more seismic monitoring instruments actuated during a seismic event.	B.2	Analyze data retrieved from 0-XT-52-75A to determine the magnitude of the vibratory ground motion.	4 hours
	AND		
	B.3	If OBE exceedance is verified, perform walkdowns of key plant equipment and structures to determine extent of damage.	8 hours
	AND		
	B.4	Restore each actuated monitoring instrument to OPERABLE status.	24 hours
	AND		
	B.5	Perform a CHANNEL CALIBRATION on each actuated monitoring instrument.	10 days
	AND		
	B.6	Analyze data retrieved from remaining seismic monitoring instruments.	14 days

TECHNICAL SURVEILLANCE REQUIREMENTS

----------NOTE----------
Refer to Table 3.3.4-1 to determine which Technical Surveillance Requirements apply for each seismic monitoring instrument.

SURVEILLANCE		FREQUENCY
TSR 3.3.4.1	Perform CHANNEL CHECK.	31 days
TSR 3.3.4.2	Perform CHANNEL OPERATIONAL TEST.	184 days
TSR 3.3.4.3	Perform CHANNEL CALIBRATION.	18 months

Table 3.3.4-1 (Page 1 of 1)

Seismic Monitoring Instrumentation

INSTRUMENTS AND SENSOR LOCATIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	MEASUREMENT RANGE
1. Strong Motion Triaxial Accelerometers (1) (5)			
a. 0-XT-52-75A (Annulus El. 703)	1	TSR 3.3.4.1 (2) TSR 3.3.4.2 (4) TSR 3.3.4.3 (3)	0 - 1.0 g
b. 0-XT-52-75B (Reactor Bldg. El. 757)	1	TSR 3.3.4.1 (2) TSR 3.3.4.2 (4) TSR 3.3.4.3 (3)	0 - 1.0 g
c. 0-XT-52-75D (D/G Bldg. El. 742)	1	TSR 3.3.4.1 (2) TSR 3.3.4.2 (4) TSR 3.3.4.3 (3)	0 - 1.0 g
2. Triaxial Strong Motion Accelerograph			
a. 0-XR-52-80 (Aux. Cont. Room. El. 757)	1	TSR 3.3.4.1 (2) TSR 3.3.4.2 (4) TSR 3.3.4.3 (3)	0 - 2.0 g

(1) With associated acceleration triggers, and control room indication on 0-XR-52-82A, -82B, -83.

(2) Except acceleration trigger.

(3) Includes acceleration trigger.

(4) Except setpoint verification.

(5) Includes recording and analyzing components on 0-R-113.

TR 3.3 INSTRUMENTATION

TR 3.3.5 RESERVED FOR FUTURE ADDITION

TR 3.3 INSTRUMENTATION

TR 3.3.6 Loose-Part Detection System

TR 3.3.6 The Loose-Part Detection System shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

----------NOTE----------
TR 3.0.3 is not applicable.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Loose-Part Detection System channels inoperable > 30 days.	A.1 Document in accordance with the Corrective Action Program.	In accordance with the Corrective Action Program.

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.6.1	Perform CHANNEL CHECK.	24 hours
TSR 3.3.6.2	Perform CHANNEL OPERATIONAL TEST.	31 days
TSR 3.3.6.3	Perform CHANNEL CALIBRATION.	18 months

TR 3.3 INSTRUMENTATION

TR 3.3.7 RESERVED FOR FUTURE ADDITION

TR 3.3 INSTRUMENTATION

3.3.8 Hydrogen Monitor

TR 3.3.8 The Hydrogen Monitor shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Hydrogen Monitor inoperable.	A.1	Restore monitor to OPERABLE status.	7 days
B. Required Action and associated Completion Time of Condition A not met.		Initiate a Corrective Actions Program (CAP) document to develop plans and schedule for restoring the monitor to OPERABLE status.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.8.1	Perform CHANNEL CALIBRATION.	18 months

TR 3.3 INSTRUMENTATION

TR 3.3.9 Power Distribution Monitoring System (PDMS)

TR 3.3.9 The PDMS shall be OPERABLE with:

a. THERMAL POWER ≥25% RTP, and

b. The required channel inputs from the plant computer for each function OPERABLE as defined in Table 3.3.9-1

APPLICABILITY: When the PDMS is used for:

a. Calibration of the Excore Neutron Flux Detection System, or

b. Monitoring the QUADRANT POWER TILT RATIO, or

c. Measurement of $F^N_{\Delta H}$ and $F_Q(Z)$, or

d. Verifying the position of a rod with inoperable position indicators.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. PDMS inoperable.	A.1 ----------NOTE---------- TR 3.0.3 is not applicable. ---------- Restore the inoperable system to OPERABLE status.	Prior to using the system for incore power distribution measurement purposes.

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.3.9.1	Perform CHANNEL CHECK for each required instrumentation channel specified in Table 3.3.9-1.	24 hours
TSR 3.3.9.2	Verify by administrative means that the surveillance requirements for each required channel specified in Table 3.3.9-1 are satisfied.	24 hours

Table 3.3.9-1 (Page 1 of 1)

Power Distribution Monitoring System (PDMS) Instrumentation

FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	SURVEILLANCE DESCRIPTION
1. RCS Cold Leg Temperature	2[7]	SR 3.3.1.10[5] SR 3.3.3.2[6]	CHANNEL CALIBRATION CHANNEL CALIBRATION
2. Reactor Power	1[1]	SR 3.3.1.2[4] SR 3.3.1.10[3]	NIS Adjustment CHANNEL CALIBRATION
3. Control Bank Position (per bank)	1[2]	SR 3.1.8.1	RPI Calibration
4. Self-Powered Detector Segments	≥ 218 total[8] and ≥ 10 per core quadrant and ≥ 4 per top core quadrant and ≥ 4 per bottom core quadrant		

(1) Either secondary calorimetric power, average power range neutron flux power, or average RCS Loop ΔT power
(2) Either the Demand Position Indication or the average of the individual Rod Position Indications
(3) Applies to average RCS Loop ΔT power only
(4) Not applicable to average RCS Loop ΔT power
(5) Applies to Narrow Range RTDs only.
(6) Applies to Wide Range RTDs only.
(7) Either Narrow Range or Wide Range RTDs.
(8) ≥ 145 Self-Powered Detector Segments are sufficient for incore power distribution measurements generated by the PDMS subsequent to the initial incore power distribution measurement in each operating cycle.

TR 3.4 REACTOR COOLANT SYSTEM (RCS)

TR 3.4.1 Safety Valves, Shutdown

TR 3.4.1 One pressurizer Code safety valve shall be OPERABLE with a lift setting of ≥ 2410 psig and ≤ 2560 psig.

----------NOTE----------
The lift setting is not required to be within the TR limit during MODES 4 and 5 for the purpose of setting the pressurizer safety valves under ambient (hot) conditions. This exception is allowed for entry and operation into and exit from MODES 4 and 5 provided a preliminary cold setting was made prior to heatup.

APPLICABILITY: MODES 4 and 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. No pressurizer Code safety valve OPERABLE.	A.1 Suspend all operations involving positive reactivity changes.	Immediately
	AND	
	A.2 Place an OPERABLE Residual Heat Removal (RHR) loop into operation in the shutdown cooling mode.	Immediately

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.4.1.1	Verify the required pressurizer safety valve OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be within ± 1% of the nominal lift setting of 2485 psig.	In accordance with the Inservice Testing Program.

TR 3.4 REACTOR COOLANT SYSTEM (RCS)

TR 3.4.2 Pressurizer Temperature Limits

TR 3.4.2 The pressurizer temperature shall be limited to:

a. Heatup of ≤ 100°F in any 1-hour period, and

b. Cooldown of ≤ 200°F in any 1-hour period.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. ----------NOTE---------- All Required Actions must be completed whenever this Condition is entered. ----------			
Pressurizer temperature not within limits.	A.1	Restore pressurizer temperature to within limits.	30 minutes
	AND		
	A.2	Perform engineering evaluation to determine effects of the out-of-limit condition on the structural integrity of the pressurizer.	72 hours
	AND		
	A.3	Determine that the pressurizer remains acceptable for continued operation.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Reduce pressurizer pressure to < 500 psig.	36 hours

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.4.2.1	----------NOTE---------- Only required during system heatup or cooldown operations. ---------- Determine that pressurizer temperatures are within limits.	30 minutes

TR 3.4 REACTOR COOLANT SYSTEM (RCS)

TR 3.4.3 Reactor Vessel Head Vent System

TR 3.4.3 Two Reactor Vessel Head Vent System (RVHVS) paths shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RVHVS path inoperable.	A.1	Initiate action to maintain the affected RVHVS path closed with power removed from the valve actuators.	Immediately
	AND		
	A.2	Restore the inoperable path to OPERABLE status.	30 days
B. Two RVHVS paths inoperable.	B.1	Restore one RVHVS path to OPERABLE status.	72 hours
C. Required Action and associated Completion Time of Condition A or B not met.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 5.	36 hours

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.4.3.1	Verify that the upstream manual RVHVS isolation valve is locked in the open position.	18 months
TSR 3.4.3.2	Operate each remotely controlled valve through at least one complete cycle of full travel from the control room.	In accordance with the Inservice Testing Program
TSR 3.4.3.3	Verify flow through the RVHVS paths during venting.	18 months

TR 3.4 REACTOR COOLANT SYSTEM (RCS)

TR 3.4.4 Chemistry

TR 3.4.4 The RCS Chemistry shall be maintained within the limits specified below:

PARAMETER	STEADY STATE LIMIT	TRANSIENT LIMIT
DISSOLVED OXYGEN	≤ 0.10 ppm	≤ 1.00 ppm
CHLORIDE	≤ 0.15 ppm	≤ 1.50 ppm
FLUORIDE	≤ 0.15 ppm	≤ 1.50 ppm

APPLICABILITY: At all times.

----------NOTE----------
With T_{avg} ≤ 250°F, the dissolved oxygen limit is not applicable.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more chemistry parameters not within Steady State Limits, in MODE 1, 2, 3, or 4.	A.1 Restore the parameter to within its Steady State Limit.	24 hours
B. One or more chemistry parameters not within the Transient Limits in MODES 1, 2, 3 and 4. OR Required Action and associated Completion Time of Condition A not met.	B.1. Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. ----------NOTE---------- All Required Actions must be completed whenever this Condition is entered. ----------			
RCS chloride or fluoride concentration not within the Steady State Limits for more than 24 hours in any condition other than MODES 1, 2, 3 and 4.	C.1	Initiate action to reduce the pressurizer pressure to ≤ 500 psig.	Immediately
	AND		
OR	C.2	Perform an engineering evaluation to determine the effects of the out-of-limit condition on the structural integrity of the RCS.	Prior to increasing the pressurizer pressure > 500 psig OR Prior to entry to MODE 4
RCS chloride or fluoride concentration not within Transient Limits in any condition other than MODES 1, 2, 3 and 4.			
	AND		
	C.3	Determine that the RCS remains acceptable for continued operation.	Prior to increasing the pressurizer pressure > 500 psig OR Prior to entry to MODE 4

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.4.4.1	----------NOTE---------- Not required with T_{avg} ≤ 250°F. ---------- Demonstrate by analysis that RCS dissolved oxygen concentration is ≤ 0.10 ppm.	72 hours
TSR 3.4.4.2	Demonstrate by analysis that RCS chloride concentration is ≤ 0.15 ppm.	72 hours
TSR 3.4.4.3	Demonstrate by analysis that RCS fluoride concentration is ≤ 0.15 ppm.	72 hours

TR 3.4 REACTOR COOLANT SYSTEM (RCS)

TR 3.4.5 Piping System Structural Integrity

TR 3.4.5 The structural integrity of ASME Code Class 1, 2, and 3 components in all systems shall be maintained in accordance with TSR 3.4.5.1 and TSR 3.4.5.2.

APPLICABILITY: All MODES.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Structural integrity of any ASME Code Class 1 component(s) not within limits.	A.1 Restore structural integrity of affected component(s) to within limit.	Prior to increasing Reactor Coolant System temperature > 50°F above the minimum temperature required by NDT considerations
	OR	
	A.2 Isolate affected component(s).	Prior to increasing Reactor Coolant System temperature > 50°F above the minimum temperature required by NDT considerations.

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Structural integrity of any ASME Code Class 2 component(s) not within limits.	B.1	Restore structural integrity of affected component(s) to within limit.	Prior to increasing Reactor Coolant System temperature to > 200°F.
	OR		
	B.2	Isolate affected component(s).	Prior to increasing Reactor Coolant System temperature to > 200°F.
C. Structural integrity of any ASME Code Class 3 component(s) not within limits.	C.1	Enter applicable Conditions and Required Actions for the affected component.	Immediately
	AND		
	C.2.1	Restore structural integrity of affected component(s) to within limit.	Within the Completion Time specified in the affected component LCO or TR.
	OR		
	C.2.2	Isolate affected component(s) from remaining system.	Within the Completion Time specified in the affected component LCO or TR.

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.4.5.1	Inspect each reactor coolant pump flywheel according to the recommendations of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, August 1975.	According to the recommendations of Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1
TSR 3.4.5.2	Verify the structural integrity of ASME Code Class 1, 2, and 3 components in all systems are in accordance with the Inservice Inspection Program.	In accordance with the Inservice Inspection Program

TR 3.6 CONTAINMENT SYSTEMS

TR 3.6.1 Ice Bed Temperature Monitoring System

TR 3.6.1 The Ice Bed Temperature Monitoring System shall be OPERABLE with at least two OPERABLE RTD channels in the ice bed at each of three basic elevations: 10' 6", 30' 9" and 55' above the floor of the ice condenser for each one-third of the ice condenser.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Ice Bed temperature not available in the main control room (Satellite Display System (SDS).	A.1 Monitor ice bed temperature at the local ice condenser temperature recorder (indicator) located in the Incore Instrumentation Room.	Once per 12 hours
B. Ice Bed Temperature Monitoring System inoperable (Integrated Computer System (ICS) - Satellite Display System (SDS)). AND Local ice condenser temperature monitoring inoperable - indicator located in the Incore Instrumentation Room.	B.1.1 Verify ice compartment lower inlet doors, intermediate deck doors, and top deck doors are closed. AND B.1.2 Verify last recorded mean ice bed temperature was ≤ 20°F and steady. AND B.1.3 Verify Ice Condenser Cooling System is OPERABLE with at least 21 air handling units, two glycol circulating pumps and three refrigerant units OPERABLE. AND	1 hour AND 12 hours thereafter 1 hour 1 hour AND 12 hours thereafter (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2.1 Restore Ice Bed Temperature Monitoring System to OPERABLE status.	30 days
	OR	
	B.2.2 Restore local temperature monitoring recorder (indicator) located in the Incore Instrumentation Room to OPERABLE status.	30 days
C. Ice Bed Temperature Monitoring System inoperable. AND Local ice condenser temperature monitoring recorder (indicator) located in the Incore Instrumentation Room inoperable. AND Ice Condenser Cooling System inoperable.	C.1.1 Verify ice compartment lower inlet doors, intermediate deck doors, and top deck doors are closed.	1 hour AND 12 hours thereafter
	AND	
	C.1.2 Verify last recorded mean ice bed temperature was ≤15°F and steady.	1 hour
	AND	
	C.2.1 Restore the Ice Condenser Cooling System to OPERABLE status.	6 days
	OR	
	C.2.2 Restore Ice Bed Temperature Monitoring System to OPERABLE status.	6 days
	OR	(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2.3 Restore local temperature monitoring recorder (indicator) located in the Incore Instrumentation Room to OPERABLE status.	6 days
D. Required Action and associated Completion Time of Condition A, B or C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.6.1.1	Perform CHANNEL CHECK on the Ice Bed Temperature Monitoring System.	12 hours

TR 3.6 CONTAINMENT SYSTEMS

TR 3.6.2 Inlet Door Position Monitoring System

TR 3.6.2 The Inlet Door Position Monitoring System shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Inlet Door Position Monitoring System inoperable due to inability to complete channel check.	A.1 Confirm the Ice Bed Temperature Monitoring System is OPERABLE with the ice bed temperature ≤ 27°F.	4 hours AND Each 4 hours thereafter
	AND	
	A.2 Document condition in accordance with the Corrective Action program and complete analysis to demonstrate the ice condenser inlet doors are shut.	14 days
B. Inlet Door position Monitoring System inoperable due to reasons other than Condition A.	B.1 Restore the Inlet Door Monitoring System to OPERABLE status.	48 hours
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Enter Technical Specification LCO 3.6.12, Condition D.	IMMEDIATELY

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.6.2.1	Perform CHANNEL CHECK.	12 hours
TSR 3.6.2.2	Perform TADOT.	18 months
TSR 3.6.2.3	Verify that the monitoring system correctly indicates the status of each inlet door as the door is opened and reclosed during its testing per TS SR 3.6.12.1, TS SR 3.6.12.3, TS SR 3.6.12.4, and TS SR 3.6.12.5.	In accordance with Technical Specification Surveillance Requirements.

TR 3.6 CONTAINMENT SYSTEMS

TR 3.6.3 Lower Compartment Cooling (LCC) System

TR 3.6.3 Two LCC trains with two fans in each train shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One LCC fan inoperable.	A.1 Restore LCC fan to OPERABLE status.	7 days
B. Two LCC fans inoperable.	B.1 Restore at least one LCC fan to OPERABLE status.	72 hours
C. Required action and associated Completion Time of Conditions A or B not met. OR More than two LCC fans inoperable.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.6.3.1	Verify that each fan can be started from the control room and operates for ≥ 15 minutes.	31 days

TR 3.7 PLANT SYSTEMS

TR 3.7.1 Steam Generator Pressure/Temperature Limitations

TR 3.7.1 The pressure of the primary and secondary side of each Steam Generator shall be ≤ 200 psig.

APPLICABILITY: Whenever the temperature of the reactor coolant or secondary side fluid in any Steam Generator ≤ 70°F.

----------NOTE----------
While this TR is not met, decreasing the temperature of the fluid in the primary or secondary side of any steam generator to ≤ 70°F is not permitted.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. ----------NOTE---------- All Required Actions must be completed whenever this Condition is entered. ----------			
Steam Generator pressure not within limits.	A.1	Reduce pressure to ≤ 200 psig.	30 minutes
	AND		
	A.2	Perform an engineering evaluation to determine the effect of the over-pressurization on the structural integrity of the Steam Generator.	Prior to increasing Steam Generator coolant temperatures to > 200°F
	AND		
	A.3	Determine that the Steam Generator remains acceptable for continued operation.	Prior to increasing Steam Generator coolant temperatures to > 200°F

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.1.1	Determine that the pressure of the primary and the secondary side of each Steam Generator is ≤ 200 psig.	1 hour

TR 3.7 PLANT SYSTEMS

TR 3.7.2 Flood Protection Plan

TR 3.7.2 The flood protection plan shall be ready for implementation to maintain the plant in a safe condition.

APPLICABILITY: When one or more of the following conditions exist:

a. Extreme flood-producing rainfall conditions in the east Tennessee watershed, or

b. Receipt of notification from River Operations (RO) that predicted flood levels based on rainfall on the ground or potential failure problems with one or more dams combined with critical headwater elevations and flood-producing rainfall may result in subsequent issuance of a Stage I flood warning.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Stage I flood warning issued.	A.1	Be in at least MODE 3.	6 hours
	AND		
	A.2	Initiate and complete the Stage I flood protection plan. Completion not required if flood warning is retracted by RO.	10 hours
	AND		
	A.3	Establish a SDM $\geq$ 5% $\Delta k/k$ and $T_{avg} \leq 350°F$.	10 hours
	AND		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.4.1 Verify that communications between the TVA RO and the Watts Bar Nuclear Plant have been established.	10 hours
	OR	
	A.4.2 Initiate and complete the Stage II flood protection procedure. Completion is not required if flood warning is retracted by RO.	27 hours
B. Stage II flood warning issued.	B.1 Initiate and complete the Stage II flood protection plan. Completion is not required if flood warning is retracted by RO.	17 hours OR Prior to flooding of the site

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.2.1	----------NOTE---------- Only required when one of the applicability criteria is met. ---------- Establish and maintain communications between Watts Bar Nuclear Plant and TVA RO Group.	3 hours

TR 3.7 PLANT SYSTEMS

TR 3.7.3 Snubbers

TR 3.7.3 All required* snubbers shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.
MODES 5 and 6 for snubbers located on systems required OPERABLE in those MODES.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required* snubber(s) removed from service.	A.1 Declare the supported system inoperable.	Immediately
B. One or more required* snubber(s) found inoperable.	B.1 Declare the supported system inoperable and enter the applicable LCO action statement for the supported system. AND B.2 Perform an engineering evaluation per Table 3.7.3-5 Note 3 on the attached component.	Immediately 72 hours
C. Required Action(s) and associated Completion Time(s) not met.	C.1 Initiate a CR.	Immediately

*Required means the snubber performs a support function that is necessary for the supported TS system to perform its specified safety function.

TECHNICAL SURVEILLANCE REQUIREMENTS

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

1. Each snubber shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program.

2. Snubbers which fail the visual inspection or the functional test acceptance criteria shall be repaired or replaced. Replacement snubbers and snubbers which have repairs which might affect the functional test results shall be tested to meet the functional test criteria before installation in the unit. Mechanical snubbers shall have met the acceptance criteria subsequent to their most recent service, and the freedom-of-motion test must have been performed within 12 months before being installed in the unit.

3. As used herein, type of snubber shall mean snubbers of the same design and manufacturer, irrespective of capacity.

SURVEILLANCE		FREQUENCY
TSR 3.7.3.1	Visually inspect each snubber in accordance with the acceptance criteria in Table 3.7.3-1.	In accordance with Table 3.7.3-2
TSR 3.7.3.2	Perform a transient event inspection of all hydraulic and mechanical snubbers in accordance with Table 3.7.3-3.	6 months following transient event
TSR 3.7.3.3	Perform a functional test on a representative sample of snubbers in accordance with Table 3.7.3-4 to determine acceptance with criteria in Table 3.7.3-5.	Each refueling outage

(continued)

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TSR 3.7.3.4	----------NOTES---------- 1. The maximum expected service life for various seals, springs, and other critical parts shall be determined and established based on engineering information and shall be extended or shortened based on monitored test results and failure history. 2. Critical parts shall be replaced so that the maximum service life will not be exceeded during a period when the snubber is required to be OPERABLE. 3. The parts replacement shall be documented and the documentation shall be retained for the duration of the unit operating license. ----------	
	Verify that the service life of hydraulic and mechanical snubbers has not been exceeded or will not be exceeded prior to the next scheduled surveillance inspection.	Each refueling outage

Table 3.7.3-1 (Page 1 of 1)

Snubber Visual Inspection Acceptance Criteria

1. Visual inspection shall verify that:

   a. There are no visible indications of damage or impaired OPERABILITY (See Note 6);

   b. Attachments to the foundation or supporting structure are functional; and

   c. Fasteners for attachment of the snubber to the component and to the snubber anchorage are functional.

2. Snubbers which appear inoperable as a result of visual inspections shall be classified as unacceptable and may be reclassified acceptable for the purpose of establishing the next visual inspection interval, provided that:

   a. The cause of the rejection is clearly established and remedied for that particular snubber and for other snubbers irrespective of type that may be generically susceptible; and

   b. The affected snubber is functionally tested in the as-found condition and determined OPERABLE per Table 3.7.3-5, Snubber Functional Testing Acceptance Criteria.

3. All snubbers connected to an inoperable common hydraulic fluid reservoir shall be counted as unacceptable for determining the next inspection interval.

4. Snubbers which have been made inoperable as the result of unexpected transients, isolated damage or other such random events, when the provisions of Table 3.7.3-3 have been met and any other appropriate corrective action implemented, shall not be counted in determining the next visual inspection interval.

5. A review and evaluation shall be performed and documented to justify continued operation with an unacceptable snubber. If continued operation cannot be justified, the snubber shall be declared inoperable and the ACTION requirements shall be met.

6. Mechanical and hydraulic snubbers are considered OPERABLE (until proven otherwise by functional testing), unless they are disconnected at either end, experienced gross deformation of the snubber or structural support, or the hydraulic fluid level is empty for hydraulic snubbers.

Table 3.7.3-2 (Page 1 of 2)

Snubber Visual Inspection Surveillance Frequency

Population or Category (Notes 1 and 2)	NUMBER OF UNACCEPTABLE SNUBBERS		
	Column A Extended Interval (Notes 3 and 6)	Column B Repeat Interval (Notes 4 and 6)	Column C Reduce Interval (Notes 5 and 6)
1	0	0	1
80	0	0	2
100	0	1	4
150	0	3	8
200	2	5	13
300	5	12	25
400	8	18	36
500	12	24	48
750	20	40	78
1000 or greater	29	56	109

Note 1: The next visual inspection interval for a snubber population or category size shall be determined based upon the previous inspection interval and the number of unacceptable snubbers found during that interval. Snubbers may be categorized, based upon their accessibility during power operation, as accessible or inaccessible. These categories may be examined separately or jointly. However, the licensee must make and document that decision before any inspection and shall use that decision as the basis upon which to determine the next inspection interval for that category.

Note 2: Interpolation between population or category size and the number of unacceptable snubbers is permissible. Use next lower integer for the value of the limit for Columns A, B, or C if that integer includes a fractional value of unacceptable snubbers as described by interpolation.

(continued)

Table 3.7.3-2 (Page 2 of 2)

Snubber Visual Inspection Surveillance Frequency

Note 3: If the number of unacceptable snubbers is equal to or less than the number in Column A, the next inspection interval may be twice the previous interval but not greater than 48 months.

Note 4: If the number of unacceptable snubbers is equal to or less than the number in Column B but greater than the number in Column A, the next inspection interval shall be the same as the previous interval.

Note 5: If the number of unacceptable snubbers is equal to or greater than the number in Column C, the next inspection interval shall be two-thirds of the previous interval. However, if the number of unacceptable snubbers is less than the number in Column C but greater than the number in Column B, the next interval shall be reduced proportionally by interpolation, that is, the previous interval shall be reduced by a factor that is one third of the ratio of the difference between the number of unacceptable snubbers found during the previous interval and the number in Column B to the difference in the numbers in Columns B and C.

Note 6: The provisions of TSR 3.0.2 are applicable for all inspection intervals up to and including 48 months.

Table 3.7.3-3 (Page 1 of 1)

Snubber Transient Event Inspection

1. An inspection shall be performed of all hydraulic and mechanical snubbers attached to sections of systems that have experienced unexpected, potentially damaging transients as determined from a review of operational data and a visual inspection of the systems within six months following such an event.

2. In addition to satisfying the visual inspection acceptance criteria, freedom-of-motion of mechanical snubbers shall be verified using one of the following:

   a. Manually induced snubber movement;

   b. Evaluation of in-place snubber piston setting; or

   c. Stroking the mechanical snubber through its full range of travel.

Table 3.7.3-4 (Page 1 of 2)

Snubber Functional Testing Plan

1. The representative sample of snubbers shall include each type and shall be tested using Sample Plan A for hydraulic snubbers and Sample Plan B for mechanical snubbers.

2. The NRC Regional Administrator shall be notified in writing of any changes to the sample plan prior to the test period.

SAMPLE PLAN A

1. At least 10% of the total hydraulic snubber population shall be functionally tested either in-place or in a bench test.

2. For each hydraulic snubber of a type that does not meet the functional test acceptance criteria of Table 3.7.3-5, an additional 10% of hydraulic snubbers shall be functionally tested until no more failures are found or until all hydraulic snubbers have been functionally tested.

SAMPLE PLAN B

1. An initial representative sample of 37 mechanical snubbers shall be functionally tested in accordance with Figure 3.7.3-1. For each mechanical snubber type which does not meet the functional test acceptance criteria of Table 3.7.3-5, another sample of at least 19 snubbers shall be tested. The results from this sample plan shall be plotted using an "Accept" line which follows the equation N = 36.49 + 18.18C where “C” is the number of snubbers which do not meet functional test acceptance criteria. If the point plotted falls on or below the "Accept" line, testing of that type of snubber may be terminated. If the point plotted falls above the "Accept" line, testing must continue until the point falls in the "Accept" region or all mechanical snubbers have been tested.

Table 3.7.3-4 (Page 2 of 2)

Snubber Functional Testing Plan

TABLE NOTES

1. Testing equipment failure during functional testing may invalidate that day's testing and allow that day's testing to resume anew at a later time provided all snubbers tested with the failed equipment during the day of equipment failure are retested.

2. The representative sample selected for the functional test sample plans shall be randomly selected from the snubbers of each type and reviewed before beginning the testing. The review shall ensure, as far as practicable, that they are representative of the various configurations, operating environments, range of size, and capacity of snubbers of each type.

3. Snubbers placed in the same location as snubbers which failed the previous functional test shall be retested at the time of the next functional test but shall not be included in the sample plan.

4. If during the functional testing, additional sampling is required due to failure of only one type of snubber, the functional test results shall be reviewed at that time to determine if additional samples should be limited to the type of snubber which has failed the functional testing.

5. Administrative controls are required for snubber removal for functional surveillance testing during plant operating MODES 1 through 4.

Table 3.7.3-5 (Page 1 of 1)

Snubber Functional Testing Acceptance Criteria

The snubber functional test shall verify that:

a. Activation (restraining action) is achieved within the specified range in both tension and compression.

b. Snubber bleed, or release rate where required, is present in both tension and compression, within the specified range (Hydraulic Snubbers).

c. The force required to initiate or maintain motion of the snubber is within the specified range in both directions of travel (Mechanical Snubbers).

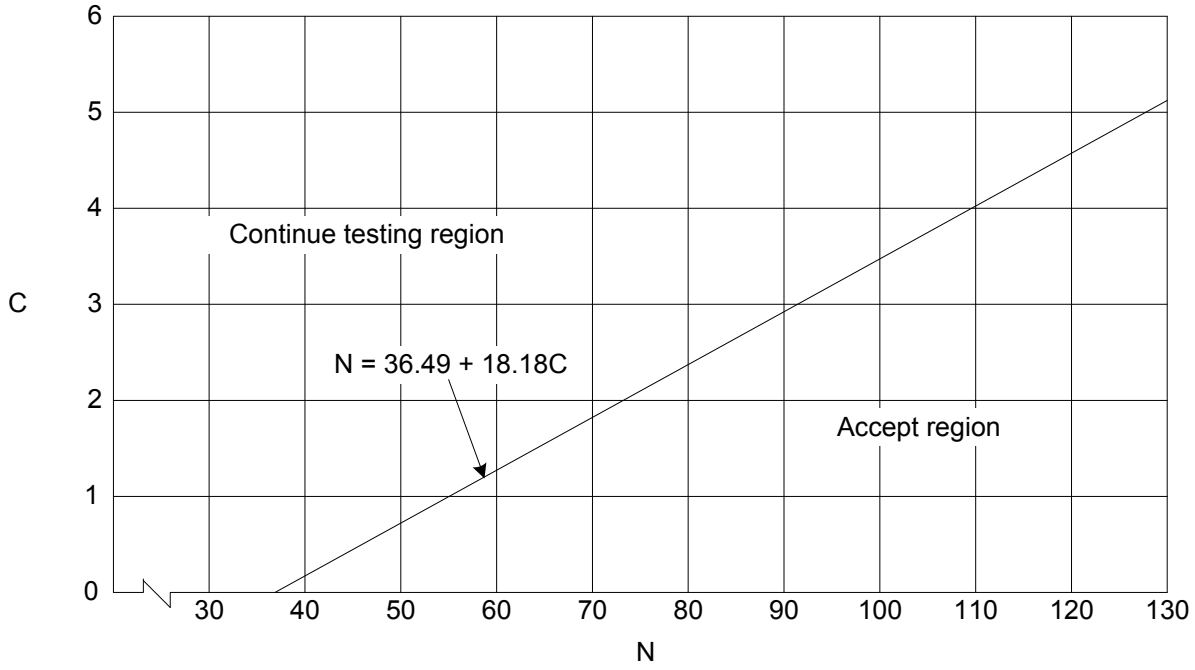
TABLE NOTES

1. Testing methods may be used to measure parameters indirectly or parameters other than those specified if those results can be correlated to the specified parameters through established methods.

2. An engineering evaluation shall be made of each failure to meet the functional test criteria to determine the cause of the failure. The results of this evaluation shall be used, if applicable, in selecting snubbers to be tested in an effort to determine the OPERABILITY of other snubbers irrespective of the type which may be subject to the same failure mode.

3. For snubbers found inoperable, an engineering evaluation shall be performed on the components to which the inoperable snubbers are attached. The purpose of this engineering evaluation shall be to determine if the components to which the inoperable snubbers are attached were adversely affected by the inoperability of the snubbers in order to ensure that the component remains capable of meeting the designed service.

4. If any snubber selected for functional testing either fails to lock up or fails to move, i.e., frozen-in-place, the cause will be evaluated and, if caused by manufacturer or design deficiency, all snubbers of the same type subject to the same defect shall be functionally tested. This testing requirement shall be independent of the requirements stated in Table 3.7.3-4 for snubbers not meeting the functional test acceptance criteria.



N = Total number of snubbers tested

C = Number of snubbers which do not meet functional test acceptance criteria

FIGURE 3.7.3-1

Sample Plan B for Snubber Functional Test

TR 3.7 PLANT SYSTEMS

TR 3.7.4. Sealed Source Contamination

TR 3.7.4. The removable contamination shall be < 0.005 microcuries for each sealed source containing radioactive material > 100 microcuries of beta and/or gamma emitting material or > 5 microcuries of alpha emitting material.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Sealed source contamination not within limit.	----------NOTE---------- TR 3.0.3 is not applicable. ----------	
	A.1 Remove sealed source from use.	Immediately
	AND	
	A.2.1 Decontaminate and repair sealed source.	Prior to returning the sealed source to use.
	OR	
	A.2.2 Dispose of sealed source in accordance with NRC regulations.	In accordance with NRC regulations.

TECHNICAL SURVEILLANCE REQUIREMENTS

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

1. The licensee, other persons specifically authorized by the NRC, or an Agreement State shall perform the Technical Surveillance Requirements.

2. The test methods shall have a detection sensitivity of ≤ 0.005 microcuries per test sample.

SURVEILLANCE		FREQUENCY
TSR 3.7.4.1	----------NOTES---------- 1. Only applicable to sources in use. 2. Only applicable to sources with half-lives > 30 days, excluding Hydrogen 3. 3. Not applicable to startup sources and fission detectors previously subjected to core flux. 4. Only applicable to sources in any form other than gas. ---------- Determine that the removable contamination is < 0.005 microcuries for each sealed source.	6 months
TSR 3.7.4.2	----------NOTES---------- 1. Only applicable to sources not in use. 2. Sealed sources and fission detector transferred without a certificate indicating the last test date shall be tested prior to being placed in use. ---------- Determine that the removable contamination is < 0.005 microcuries for each sealed source and fission detector.	Within 6 months prior to use or transfer to another licensee

(continued)

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TSR 3.7.4.3	----------NOTE---------- Only applicable to startup sources and incore fission detectors not in use. ---------- Determine that the removable contamination is < 0.005 microcuries for each startup source and incore fission detector.	Within 31 days prior to being installed <u>AND</u> Following repair or maintenance to the source
TSR 3.7.4.4	----------NOTE---------- Only applicable to excore fission detectors. ---------- Determine that the removable contamination is < 0.005 microcuries for each excore fission detector.	Within 31 days prior to being installed <u>AND</u> Following repair or maintenance to the source

TR 3.7 PLANT SYSTEMS

TR 3.7.5 Area Temperature Monitoring

TR 3.7.5 The normal temperature limit of each area shown in Table 3.7.5-1 shall not be exceeded for > 8 hours and the abnormal temperature limits shall not be exceeded.

APPLICABILITY: Whenever the affected equipment in an area is required to be OPERABLE.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more areas exceeding normal temperature limits for > 8 hours.	A.1 ----------NOTE---------- TR 3.0.3 is not applicable. ----------	
	Document in accordance with the Corrective Action Program and include a record of the cumulative time and the amount by which the temperature in the affected area(s) exceeded the limit(s) and an analysis to demonstrate OPERABILITY of the affected equipment.	In accordance with the Corrective Action Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One or more areas exceeding abnormal temperature limits except for the IPS Mechanical or Electrical Equipment Rooms (Areas 31, 32, or 34).	B.1.1	Restore the area(s) to within normal temperature limits.	4 hours
	OR		
	B.1.2	Declare the affected equipment in the affected area(s) inoperable.	4 hours
	AND		
	B.2	Document in accordance with the Corrective Action Program and include a record of the cumulative time and the amount by which the temperature in the affected area(s) exceeded the limit(s) and an analysis to demonstrate OPERABILITY of the affected equipment.	In accordance with the Corrective Action Program
C. Mechanical or Electrical Equipment Rooms in Intake Pumping Station (Areas 31, 32, or 34) less than 40°F and greater than 32°F.	C.1	Initiate action to maintain temperatures greater than 32°F.	24 hours
	AND		
	C.2	Restore temperatures to within normal limits.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Mechanical or Electrical Equipment Rooms in Intake Pumping Station (Areas 31, 32, or 34) 32°F or less.	D.1 Declare the affected equipment in the affected area(s) inoperable.	Immediately
	AND	
	D.2 Document in accordance with the Corrective Action Program and include a record of the cumulative time and the amount by which the temperature in the affected area(s) exceeded the limit(s) and an analysis to demonstrate OPERABILITY of the affected equipment.	In accordance with the Corrective Action Program

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.7.5.1	Verify each area temperature is within limits.	12 hours

Table 3.7.5-1 (Page 1 of 2)

Area Temperature Monitoring

	AREA	NORMAL LIMIT (°F)	ABNORMAL LIMIT (°F)
1.	Aux Bldg el 772 next to 480V Sd Bd transformer 1A2-A.	≤ 104	≤ 110
2.	Aux Bldg el 772 next to 480V Sd Bd transformer 1B1-B.	≤ 104	≤ 110
3.	Aux Bldg el 772 next to 480V Sd Bd transformer 2A2-A.	≤ 104	≤ 110
4.	Aux Bldg el 772 next to 480V Sd Bd transformer 2B2-B.	≤ 104	≤ 110
5.	Aux Bldg el 772 next to 480V Rx MOV Bd 1A2-A.	≤ 83	≤ 104
6.	Aux Bldg el 772 next to 480V Rx MOV Bd 2A2-A.	≤ 83	≤ 104
7.	Aux Bldg el 772 next to 480V Rx MOV Bd 2B2-B.	≤ 83	≤ 104
8.	Aux Bldg el 772 across from spare 125V vital battery charger 1-S.	≤ 83	≤ 104
9.	Aux Bldg el 772 U1 Mech Equip Room.	≤ 91	≤ 104
10.	Aux Bldg el 757 U1 Sd Bd room behind stairs S-A3.	≤ 85	≤ 104
11.	Aux Bldg el 757 U2 Sd Bd room behind stairs S-A13.	≤ 85	≤ 104
12.	Aux Bldg el 757 U1 Refueling beside Aux boration makeup tk.	≤ 104	≤ 115
13.	Aux Bldg el 737 U2 outside supply fan room.	≤ 104	≤ 110
14.	Aux Bldg el 713 U2 across from AFW pumps.	≤ 104	≤ 110
15.	Aux Bldg el 692 U2 outside AFW pump room door.	≤ 104	≤ 110
16.	Aux Bldg el 692 U2 near boric acid concentrate filter vault.	≤ 104	≤ 110
17.	Aux Bldg el 676 next to O-L-629.	≤ 104	≤ 110
18.	North steam valve vault room U2. (at affected MSSVs)	≥ 50	≥ 50
19.	South steam valve vault room U2. (at affected MSSVs)	≥ 50	≥ 50

(continued)

Table 3.7.5-1 (Page 2 of 2)

Area Temperature Monitoring

AREA	NORMAL LIMIT (°F)	ABNORMAL LIMIT (°F)
20. Add Equip Bldg U2 el 729 between UHI accumulators.	≤ 92	≤ 110
21. CB Main Control Room south wall.	≤ 80	≤ 104
22. CB Main Control Room across from 1-M-9.	≤ 80	≤ 104
23. CB Computer room el 708 center of room.	≤ 74	≤ 104
24. CB Aux. Instrument Room el 708.	≤ 90	≤ 104
25. D/G Bldg el 742 2B-B D/G room on wall by battery charger.	≤ 104	≤ 120
26. D/G Bldg el 742 1A-A D/G Room near D/G set.	≥ 50	≥ 50
27. D/G Bldg el 742 1B-B D/G Room near D/G set.	≥ 50	≥ 50
28. D/G Bldg el 742 2A-A D/G Room near D/G set.	≥ 50	≥ 50
29. D/G Bldg el 742 2B-B D/G Room near D/G set.	≥ 50	≥ 50
30. D/G Bldg el 760.5 next to 480V diesel Aux Bd 2B1-B.	≤ 104	≤ 120
31. IPS Mechanical Equipment Room 1 el 722 near ERCW and HPFP Instruments and sense lines.	≥50 ≤104	≥40 ≤115
32. IPS Mechanical Equipment Room 2 el 722 near ERCW and HPFP Instruments and sense lines.	≥50 ≤104	≥40 ≤115
33. IPS el 741 in B train ERCW pump room.	≤ 120	≤ 120
34. IPS el 711 next to 480V IPS board and transformer (A bus).	≥50 ≤104	≥40 ≤115
35. IPS el 711 next to 480V IPS board and transformer (B bus).	≤ 104	≤ 115

TR 3.8 ELECTRICAL POWER SYSTEMS

TR 3.8.1 Isolation Devices

TR 3.8.1 All circuit breakers actuated by fault currents that are used as isolation devices protecting 1E busses from non-qualified loads shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required circuit breakers inoperable.	A.1	Restore the inoperable circuit breaker(s) to OPERABLE status.	8 hours
	OR		
	A.2.1	Trip or remove the inoperable circuit breaker(s).	8 hours
	AND		
	A.2.2	Verify that inoperable circuit breaker(s) are tripped or removed.	Once per 7 days thereafter
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.8.1.1	----------NOTES---------- 1. Molded case circuit breakers selected for functional testing shall be selected on a rotating basis. 2. The functional test shall be conducted by simulating a fault current with an approved test set and verifying that the molded case circuit breaker functions as designed. 3. For each molded-case circuit breaker found inoperable during functional tests, an additional representative sample of 10% of the defective type shall be functionally tested until no more failures are found or all of that type has been functionally tested. ---------- Perform functional test on representative sample of ≥ 10% of each type of molded-case circuit breaker.	18 months
TSR 3.8.1.2	----------NOTES---------- 1. Electrically-operated circuit breakers selected for functional testing shall be selected on a rotating basis. 2. The functional test shall be conducted by simulating a fault current with an approved test set and verifying that each electrically-operated circuit breaker functions as designed. 3. For each electrically-operated circuit breaker found inoperable during functional tests, an additional representative sample of 10% of the defective type shall be functionally tested until no more failures are found or all of that type has been functionally tested. ---------- Perform functional test on representative sample of ≥ 10% of each type of electrically-operated circuit breaker.	18 months

(continued)

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TSR 3.8.1.3	Perform a CHANNEL CALIBRATION of associated protective relays for medium voltage circuits (6.9 kV).	18 months
TSR 3.8.1.4	----------NOTE---------- For each circuit breaker found inoperable during functional tests, an additional representative sample of 10% of the defective type shall be functionally tested until no more failures are found or all of that type has been functionally tested. ---------- Perform an integrated system functional test on each medium voltage (6.9 kV) breaker which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and control circuits function as designed.	18 months
TSR 3.8.1.5	Inspect each circuit breaker and perform preventive maintenance in accordance with procedures prepared in conjunction with the manufacturers and EPRI NP-7410-V3, Rev. 1 recommendations for electrically operated breakers and Class 1E MCCB.	72 months

TR 3.8 ELECTRICAL POWER SYSTEMS

TR 3.8.2. Containment Penetration Conductor Overcurrent Protection Devices

TR 3.8.2. All containment penetration conductor overcurrent protection devices shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment penetration conductor overcurrent protection devices inoperable.	A.1 Restore the protective device(s) to OPERABLE status.	72 hours
	OR	
	A.2.1 De-energize the circuit(s) by tripping the associated backup circuit breaker or removing the inoperable circuit breaker.	72 hours
	AND	
	A.2.2 Declare the affected system or component inoperable.	72 hours
	AND	
	A.2.3 Verify the backup circuit breaker to be tripped or the inoperable circuit breaker removed.	Once per 7 days thereafter

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

TECHNICAL SURVEILLANCE REQUIREMENTS

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

1. All containment penetration conductor overcurrent protection devices listed in Drawing Series 45A710 (excluding fuses) shall be demonstrated OPERABLE by performance of the following Technical Surveillance Requirements.

2. Technical Surveillance Requirements 3.8.2.1 and 3.8.2.2 apply to at least one 6900-volt reactor coolant pump circuit such that all reactor coolant pump circuits are demonstrated OPERABLE at least once per 72 months.

SURVEILLANCE		FREQUENCY
TSR 3.8.2.1	Perform a CHANNEL CALIBRATION of associated protective relays for medium voltage circuits (6.9 kV).	18 months

(continued)

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TSR 3.8.2.2	----------NOTE---------- For each circuit breaker found inoperable during functional tests, an additional representative sample of 10% of the defective type shall be functionally tested until no more failures are found, or all of that type has been functionally tested. ---------- Perform an integrated system functional test on each medium voltage (6.9 kV) breaker which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and control circuits function as designed.	18 months
TSR 3.8.2.3	----------NOTES---------- 1. Molded case circuit breakers selected for functional testing shall be selected on a rotating basis. 2. The functional test shall be conducted by simulating a fault current with an approved test set and verifying that each circuit breaker functions as designed. 3. For each molded case circuit breaker found inoperable during functional tests, an additional representative sample of 10% of all the defective type shall be functionally tested until no more failures are found or all of that type has been functionally tested. ---------- Select and functionally test a representative sample of ≥10% of each type of molded case circuit breaker.	18 months

(continued)

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TSR 3.8.2.4	----------NOTES---------- 1. Electrically-operated circuit breakers selected for functional testing shall be selected on a rotating basis. 2. The functional test shall be conducted by simulating a fault current with an approved test set and verifying that each electrically-operated circuit breaker functions as designed. 3. For each electrically-operated circuit breaker found inoperable during functional tests, an additional representative sample of 10% of the defective type shall be functionally tested until no more failures are found or all of that type has been functionally tested. ---------- Perform functional test on representative sample of ≥ 10% of each type of electrically-operated circuit breaker.	18 months
TSR 3.8.2.5	Inspect each circuit breaker and perform preventive maintenance in accordance with procedures prepared in conjunction with the manufacturer's and EPRI NP-7410-V3, Rev. 1 recommendations:	
	1. For electrically operated breakers and Class 1E MCCB	72 months
	2. For non-Class 1E MCCB.	96 months

TR 3.8 ELECTRICAL POWER SYSTEMS

TR 3.8.3 Motor-Operated Valves Thermal Overload Bypass Devices

TR 3.8.3 The thermal overload bypass devices integral with the motor starter of each valve listed in Table 3.8.3-1 shall be OPERABLE.

APPLICABILITY: Whenever the motor-operated valve is required to be OPERABLE.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Thermal overload protection not bypassed when required for one or more of the valves listed in Table 3.8.3-1.	A.1 Restore inoperable device to OPERABLE status.	8 hours
	OR	
	A.2 Provide a means to bypass the thermal overload.	8 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Declare the affected valve(s) inoperable.	Immediately
	AND	
	B.2 Apply the appropriate ACTION statement(s) of the affected system(s).	Immediately

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
TSR 3.8.3.1 Perform TADOT of the bypass circuitry.	18 months

Table 3.8.3-1 (Page 1 of 6)

Motor-Operated Valves Thermal Overload Devices
Which Are Bypassed Under Accident Conditions

VALVE NO.	FUNCTION
2-FCV-62-63	Isolation for Seal Water Filter
2-FCV-62-90	ECCS Operation
2-FCV-62-91	ECCS Operation
2-FCV-62-61	Containment Isolation
2-LCV-62-132	ECCS Operation
2-LCV-62-133	ECCS Operation
2-LCV-62-135	ECCS Operation
2-LCV-62-136	ECCS Operation
2-FCV-74-1	Open for Normal Plant Cooldown
2-FCV-74-2	Open for Normal Plant Cooldown
2-FCV-74-3	ECCS Operation
2-FCV-74-21	ECCS Operation
2-FCV-74-12	RHR Pump, Minimum flow -- Protects Pump
2-FCV-74-24	RHR Pump, Minimum flow -- Protects Pump
2-FCV-74-33	ECCS Operation
2-FCV-74-35	ECCS Operation
2-FCV-63-7	ECCS Operation
2-FCV-63-6	ECCS Operation
2-FCV-63-156	ECCS Flow Path
2-FCV-63-157	ECCS Flow Path
2-FCV-63-25	BIT Injection
2-FCV-63-26	BIT Injection
2-FCV-63-1	ECCS Operation
2-FCV-63-72	ECCS Flow Path from Containment Sump
2-FCV-63-73	ECCS Flow Path from Containment Sump
2-FCV-63-8	ECCS Flow Path
2-FCV-63-11	ECCS Flow Path

(continued)

Table 3.8.3-1 (Page 2 of 6)

Motor-Operated Valves Thermal Overload Devices
Which Are Bypassed Under Accident Conditions

VALVE NO.	FUNCTION
2-FCV-63-93	ECCS Cooldown Flow Path
2-FCV-63-94	ECCS Cooldown Flow Path
2-FCV-63-172	ECCS Flow Path
2-FCV-63-5	ECCS Flow Path
2-FCV-63-47	Train Isolation
2-FCV-63-48	Train Isolation
2-FCV-63-4	SI Pump Minimum Flow
2-FCV-63-175	SI Pump Minimum Flow
2-FCV-63-3	SI Pump Minimum Flow
2-FCV-63-152	ECCS Recirculation
2-FCV-63-153	ECCS Recirculation
2-FCV-3-33	Quick Closing Isolation
2-FCV-3-47	Quick Closing Isolation
2-FCV-3-87	Quick Closing Isolation
2-FCV-3-100	Quick Closing Isolation
2-FCV-1-15	Steam Supply to Auxiliary FWP Turbine
2-FCV-1-16	Steam Supply to Auxiliary FWP Turbine
2-FCV-3-179A	ERCW System Supply to Pump
2-FCV-3-179B	ERCW System Supply to Pump
2-FCV-3-136A	ERCW System Supply to Pump
2-FCV-3-136B	ERCW System Supply to Pump
2-FCV-3-116A	ERCW System Supply to Pump
2-FCV-3-116B	ERCW System Supply to Pump
2-FCV-3-126A	ERCW System Supply to Pump
2-FCV-3-126B	ERCW System Supply to Pump
2-FCV-70-143	Isolation for Excess Letdown Heat Exchanger

(continued)

Table 3.8.3-1 (Page 3 of 6)

Motor-Operated Valves Thermal Overload Devices
Which Are Bypassed Under Accident Conditions

VALVE NO.	FUNCTION
2-FCV-70-92	Isolation for RCP Oil Coolers & Therm B
2-FCV-70-90	Isolation for RCP Oil Coolers & Therm B
2-FCV-70-87	Isolation for RCP Oil Coolers & Therm B
2-FCV-70-89	Isolation for RCP Oil Coolers & Therm B
2-FCV-70-140	Isolation for RCP Oil Coolers & Therm B
2-FCV-70-134	Isolation for RCP Oil Coolers & Therm B
2-FCV-67-123	CS Heat Exchanger Supply
2-FCV-67-125	CS Heat Exchanger Supply
2-FCV-67-124	CS Heat Exchanger Discharge
2-FCV-67-126	CS Heat Exchanger Discharge
2-FCV-67-146	CCS Heat Exchanger Throttling
2-FCV-67-83	Containment Isolation Lower Comp Clr
2-FCV-67-88	Containment Isolation Lower Comp Clr
2-FCV-67-87	Containment Isolation Lower Comp Clr
2-FCV-1-51	AFPT Trip and Throttle Valve Comp Clr
2-FCV-67-95	Containment Isolation Lower Comp Clr
2-FCV-67-96	Containment Isolation Lower Comp Clr
2-FCV-67-91	Containment Isolation Lower Comp Clr
2-FCV-67-103	Containment Isolation Lower Comp Clr
2-FCV-67-104	Containment Isolation Lower Comp Clr
2-FCV-67-99	Containment Isolation Lower Comp Clr
2-FCV-67-111	Containment Isolation Lower Comp Clr
2-FCV-67-112	Containment Isolation Lower Comp Clr
2-FCV-67-107	Containment Isolation Lower Comp Clr
2-FCV-67-130	Containment Isolation Upper Comp Clr
2-FCV-67-131	Containment Isolation Upper Comp Clr
2-FCV-67-295	Containment Isolation Upper Comp Clr

(continued)

Table 3.8.3-1 (Page 4 of 6)

Motor-Operated Valves Thermal Overload Devices
Which Are Bypassed Under Accident Conditions

VALVE NO.	FUNCTION
2-FCV-67-134	Containment Isolation Upper Comp Clr
2-FCV-67-296	Containment Isolation Upper Comp Clr
2-FCV-67-133	Containment Isolation Upper Comp Clr
2-FCV-67-139	Containment Isolation Upper Comp Clr
2-FCV-67-297	Containment Isolation Upper Comp Clr
2-FCV-67-138	Containment Isolation Upper Comp Clr
2-FCV-67-142	Containment Isolation Upper Comp Clr
2-FCV-67-298	Containment Isolation Upper Comp Clr
2-FCV-67-141	Containment Isolation Upper Comp Clr
2-FCV-72-21	Containment Spray Pump Suction
2-FCV-72-22	Containment Spray Pump Suction
2-FCV-72-2	Containment Spray Isolation
2-FCV-72-39	Containment Spray Isolation
2-FCV-72-40	RHR Containment Spray Isolation
2-FCV-72-41	RHR Containment Spray Isolation
2-FCV-72-44	Containment Sump to Header A - Containment Spray
2-FCV-72-45	Containment Sump to Header B - Containment Spray
2-FCV-26-240	Containment Isolation
2-FCV-26-243	RCP Containment Spray Isolation
2-FCV-68-332	RCS PRZR Relief
2-FCV-68-333	RCS PRZR Relief
2-FCV-70-153	Unit 2 RHR Heat Exchanger B-B Outlet
2-FCV-70-156	Unit 2 RHR Heat Exchanger A-A Outlet
1-FCV-67-9A	ERCW Strainer Backwash
2-FCV-67-9A	ERCW Strainer Backwash
1-FCV-67-9B	ERCW Strainer Flush
2-FCV-67-9B	ERCW Strainer Flush

(continued)

Table 3.8.3-1 (Page 5 of 6)

Motor-Operated Valves Thermal Overload Devices
Which Are Bypassed Under Accident Conditions

VALVE NO.	FUNCTION
1-FCV-67-10A	ERCW Strainer Backwash
2-FCV-67-10A	ERCW Strainer Backwash
1-FCV-67-10B	ERCW Strainer Flush
2-FCV-67-10B	ERCW Strainer Flush
2-FCV-67-89	Containment Isolation Lower Comp Clr
2-FCV-67-97	Containment Isolation Lower Comp Clr
2-FCV-67-105	Lower Containment Isolation Lower Comp Clr
2-FCV-67-113	Lower Containment Isolation Lower Comp Clr
2-FCV-67-143	CCS Heat Exchanger Discharge
0-FCV-67-144	CCS Heat Exchanger Bypass
0-FCV-67-152	CCS Heat Exchanger Discharge
0-FCV-67-205	Nonessential Equipment Isolation
0-FCV-67-208	Station Service/Control Air Supply
2-FCV-70-183	Sample Heat Exchanger Header Outlet
2-FCV-70-100	RCP Oil Cooler Supply Containment Isolation
2-FCV-70-215	Sample Heat Exchanger Header Inlet
2-FCV-74-8	RHR Isolation Bypass
2-FCV-74-9	RHR Isolation Bypass
1-FCV-70-153	Unit 1 RHR Heat Exchanger B-B Outlet
0-FCV-70-194	SFPCS Heat Exchanger Supply Header
1-FCV-67-66	DG Heat Exchanger 1A1 & 1A2 Supply
2-FCV-67-66	DG Heat Exchanger 2A1 & 2A2 Supply
1-FCV-67-67	DG Heat Exchanger 1B1 & 1B2 Supply
2-FCV-67-67	DG Heat Exchanger 2B1 & 2B2 Supply
1-FCV-67-143	CCS Heat Exchanger Discharge
1-FCV-67-146	CCS Heat Exchanger Throttling

(continued)

Table 3.8.3-1 (Page 6 of 6)

Motor-Operated Valves Thermal Overload Devices
Which Are Bypassed Under Accident Conditions

VALVE NO.	FUNCTION
1-FCV-67-65	DG Heat Exchanger Discharge 1B1 & 1B2 Supply
1-FCV-67-68	DG Heat Exchanger Discharge 1A1 & 1A2 Supply
2-FCV-67-65	DG Heat Exchanger Discharge 2B1 & 2B2 Supply
2-FCV-67-68	DG Heat Exchanger Discharge 2A1 & 2A2 Supply
1-FCV-70-156	RHR Heat Exchanger A-A Outlet

TR 3.8 ELECTRICAL POWER SYSTEMS

TR 3.8.4 Submerged Component Circuit Protection

TR 3.8.4 The submerged component circuits associated with valves 2-FCV-74-1, 2-FCV-74-2, 2-FCV-74-8 and 2-FCV-74-9 shall be de-energized and the submerged components circuits associated with each component as shown in Table 3.8.4-1 shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more submerged components circuits associated with valves 2-FCV-74-1, 2-FCV-74-2, 2-FCV-74-8, and 2-FCV-74-9 energized with RCS pressure ≥ 425 psig or one or more submerged components circuits inoperable for components listed in Table 3.8.4-1.	A.1 Restore the inoperable circuit to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.8.4.1	Verify that valves 2-FCV-74-1, 2-FCV-74-2, 2-FCV-74-8, and 2-FCV-74-9 are de-energized.	31 days
TSR 3.8.4.2	Verify that the components as shown in Table 3.8.4-1 are automatically de-energized on a simulated accident signal and that the components remain de-energized when the accident signal is reset.	18 months

Table 3.8.4-1 (Page 1 of 4)

Submerged Components With Automatic De-energization Under Accident Conditions

BOARD	COMPT	LOAD	FCTN
6.9kV SHUTDOWN BOARD 2A-A	20	2-DPL-68-341A-A	SI
	21	2-DPL-68-341F	SI
6.9kV SHUTDOWN BOARD 2B-B	20	2-DPL-68-341D-B	SI
	21	2-DPL-68-341H*	SI
480V SHUTDOWN BOARD 2A1-A	7B	2-MTR-30-83/1-A	CIB
	7D	2-MTR-30-83/2-A	CIB
	7C	2-MTR-30-74-A	CIB
480V SHUTDOWN BOARD 2B1-B	7C	2-MTR-30-92/1-B	CIB
	10D	2-MTR-30-92/2-B	CIB
	7D	2-MTR-30-75-B	CIB
480V SHUTDOWN BOARD 2A2-A	7A	2-MTR-30-88/1-A	CIB
	8A	2-MTR-30-88/2-A	CIB
	7D	2-MTR-30-77-A	CIB
480V SHUTDOWN BOARD 2B2-B	7B	2-MTR-30-80/1-B	CIB
	10C	2-MTR-30-80/2-B	CIB
	7D	2-MTR-30-78-B	CIB
480V REACTOR MOV BOARD 2A1-A	16A	2-MTR-31-265	CIA
	17E	2-PO-213-A1/(1-5)	SI
	18F2	2-PO-213-A1/(6-10)	SI
480V REACTOR MOV BOARD 2B1-B	16A	2-MTR-31-266	CIA
	16E	2-PO-213-B1/(1-5)	SI
	17E	2-PO-213-B1/(6-10)	SI

(continued)

Table 3.8.4-1 (Page 2 of 4)

Submerged Components With Automatic De-energization Under Accident Conditions

BOARD	COMPT	LOAD	FCTN
480V REACTOR VENT BOARD 2A-A	2A	2-MTR-77-125A	SI
	9B	2-MTR-30-95	CIB
	10B	2-MTR-30-99	CIB
	11D	2-MTR-77-4	CIA
480V REACTOR VENT BOARD 2B-B	2A	2-MTR-77-125B	SI
	9B	2-MTR-30-97	CIB
	10B	2-MTR-30-100	CIB
	11D	2-MTR-77-6	CIA
125VDC VITAL BATTERY BOARD III	A6	2-FCV-62-72-A	CIA
	A7	2-FCV-62-73-A	CIA
	A8	2-FCV-62-74-A	CIA
	A17	2-FCV-62-76-A	CIA
	A31	2-FCV-63-71-A	CIA
	B30	2-FSV-30-56-A	CVI
	B32	2-FSV-30-20-A	CVI
	B36	2-FSV-30-40-A	CVI
	C3	2-FCV-31-306-A	CIA
	C4	2-FCV-31-308-A	CIA
	C22	2-FCV-1-181-A	CIA
	C38	2-FCV-1-183-A	CIA
	C46	2-FCV-30-17-A	CVI

(continued)

Table 3.8.4-1 (Page 3 of 4)

Submerged Components With Automatic De-energization Under Accident Conditions

BOARD	COMPT	LOAD	FCTN
125VDC VITAL BATTERY BOARD IV	A20	2-FCV-43-2-B	CIA
	A21	2-FCV-43-11-B	CIA
	A22	2-FCV-43-22-B	CIA
	A23	2-FCV-43-34-B	CIA
	A24	2-FCV-77-16-B	CIA
	A43	2-FCV-77-127-B	CIA
	A44	2-FCV-77-9-B	CIA
	A45	2-FCV-77-18-B	CIA
	B26	2-FCV-30-8/50-B	CVI
	B27	2-FCV-90-108-B	CVI
	B28	2-FCV-90-110-B	CVI
	B32	2-FCV-30-15/57-B	CVI
	B33	2-FCV-90-114-B	CVI
	B34	2-FCV-30-58-B	CVI
	B36	2-FCV-90-116-B	CVI
	C5	2-FCV-31-327-B	CIA
	C6	2-FCV-30-329-B	CIA
	C21	2-FCV-43-75-B	CIA
	C26	2-FCV-61-122-B	CIA
	C34	2-FCV-90-109-B	CVI
	C35	2-FCV-90-115-B	CVI
	C41	2-FCV-43-54D-B	CIA
	C42	2-FCV-43-56D-B	CIA
	C43	2-FCV-43-59D-B	CIA
	C44	2-FCV-43-63D-B	CIA

Table 3.8.4-1 (Page 4 of 4)

Submerged Components With Automatic De-energization Under Accident Conditions

CIA: CONTAINMENT ISOLATION PHASE A

CIB: CONTAINMENT ISOLATION PHASE B

CVI: CONTAINMENT VENT ISOLATION

SI: SAFETY INJECTION

*: No adverse impact on power supplies if energized after accident signal reset.

TR 3.9 REFUELING OPERATIONS

TR 3.9.1 RESERVED FOR FUTURE ADDITION

TR 3.9 REFUELING OPERATIONS

TR 3.9.2 Communications

TR 3.9.2 Direct communications shall be maintained between the control room and personnel at the refueling station.

APPLICABILITY: During CORE ALTERATIONS.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Direct communications between the control room and personnel at the refueling station cannot be maintained.	A.1 Suspend all CORE ALTERATIONS.	Immediately

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.9.2.1	Demonstrate that direct communications between the control room and personnel at the refueling station are established.	1 hour prior to the start of CORE ALTERATIONS <u>AND</u> Each 12 hours during CORE ALTERATIONS

TR 3.9 REFUELING OPERATIONS

TR 3.9.3 Refueling Machine

TR 3.9.3 The Refueling Machine and Auxiliary Hoist shall be used for movement of fuel assemblies or drive shafts and shall be OPERABLE as follows:

a. The Refueling Machine shall have a capacity of ≥ 3150 pounds, and two electrical overload cutoff limits of ≤ 2650 pounds and ≤ 2800 pounds, respectively.

b. The Auxiliary Hoist shall have a capacity of ≥ 1200 pounds and a load indicator shall be used to indicate the lifting of loads > 1190 pounds.

APPLICABILITY: During movement of fuel assemblies or drive shafts within the reactor pressure vessel.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refueling Machine inoperable.	A.1 Suspend use of Refueling Machine from operations involving the movement of fuel assemblies within the reactor pressure vessel.	Immediately
B. Auxiliary Hoist inoperable.	B.1 Suspend use of Auxiliary Hoist from operations involving the movement of drive shafts within the reactor pressure vessel.	Immediately

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.9.3.1	For each required Refueling Machine, perform a load test of ≥ 3150 pounds and demonstrate an automatic electrical load cutoff before the crane load is > 2650 pounds. Demonstrate a second automatic electrical load cutoff before the crane load is > 2800 pounds.	18 months
TSR 3.9.3.2	For each required Auxiliary Hoist and associated load indicator, perform a load test of ≥ 1200 pounds.	Within 100 hours prior to start of drive shaft movements within the reactor pressure vessel

TR 3.9 REFUELING OPERATIONS

TR 3.9.4 Crane Travel - Spent Fuel Storage Pool Building

TR 3.9.4 Loads > 2059 pounds shall be prohibited from travel over fuel assemblies in the spent fuel pool.

APPLICABILITY: With fuel assemblies in the spent fuel pool.

----------NOTE----------
TR 3.0.3 is not applicable.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Technical Requirement not met.	A.1 Place the crane load in a safe condition.	Immediately

TECHNICAL SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.9.4.1	Demonstrate crane interlocks and physical stops which prevent crane travel over fuel assemblies to be OPERABLE.	Within 7 days prior to crane use <u>AND</u> At least once per 7 days thereafter during crane operation

5.0 ADMINISTRATIVE CONTROLS

5.1 Technical Requirements Control Program

This Program provides a means for controlling changes or additions to the Technical Requirements and their Bases.

5.1.1 Changes or additions to the Technical Requirements Manual (TRM) shall be made under appropriate administrative controls and reviews.

5.1.2 Licensees may make changes or additions to the TRM without prior NRC approval provided the changes have been determined not to be candidates for inclusion in the Technical Specifications (TS) and not to require NRC approval pursuant to 10 CFR 50.59. The changes to the TRM shall include the following:

a. Include screening the change against the criteria contained in 10 CFR 50.36(c)(2)(ii).

b. The change does not require NRC approval pursuant to 10 CFR 50.59.

5.1.3 The Technical Requirements Control Program shall contain provisions to ensure that changes or additions to the TRM are accurately reflected in the FSAR as appropriate.

5.1.4 Proposed changes or additions that do not meet the criteria of 5.1.2 shall be reviewed and approved by the NRC prior to implementation. Changes or additions to the TRM implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

B 3.0 TECHNICAL REQUIREMENT (TR) AND TECHNICAL SURVEILLANCE REQUIREMENT (TSR) APPLICABILITY

BASES

TRs

TR 3.0.1 through TR 3.0.6 establish the general requirements applicable to all Requirements and apply at all times, unless otherwise stated.

TR 3.0.1

TR 3.0.1 establishes the Applicability statement within each individual Requirement as the requirements for when the TR is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Requirement).

TR 3.0.2

TR 3.0.2 establishes that upon discovery of a failure to meet a TR, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of a TR are not met. This Requirement establishes that:

a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Requirement; and

b. Completion of the Required Actions is not required when a TR is met within the specified Completion Time, unless otherwise specified.

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the TR must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Requirement is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action 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.

(continued)

BASES

TRs

TR 3.0.2 (continued)

Completing the Required Actions is not required when a TR is met or is no longer applicable, unless otherwise stated in the individual Technical Requirements.

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 exist. The individual TR's ACTIONS specify the Required Actions where this is the case. An example of this is in TR 3.4.2, "Pressurizer Temperature Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Alternatives that would not result in redundant equipment being inoperable should be used instead. Doing so limits the time both subsystems/trains of a safety function are inoperable and limits the time other conditions exist which result in TR 3.0.3 being entered. Individual Requirements may specify a time limit for performing a TSR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Requirement becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Requirement becomes applicable, and the ACTIONS Condition(s) are entered.

BASES

TRs (continued)

TR 3.0.3

TR 3.0.3 establishes the actions that must be implemented when a TR is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering TR 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that TR 3.0.3 be entered immediately.

This Requirement delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the TR and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

Upon entering TR 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Requirement applies. The use and interpretation of specified times to complete the actions of TR 3.0.3 are consistent with the discussion of Section 1.3, Completion Times.

(continued)

BASES

TRs

TR 3.0.3 (continued)

A unit shutdown required in accordance with TR 3.0.3 may be terminated and TR 3.0.3 exited if any of the following occurs:

a. The TR is now met.

b. A Condition exists for which the Required Actions have now been performed.

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time TR 3.0.3 is exited.

The time limits of TR 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is reached in 2 hours, then the time allowed for reaching MODE 4 is the next 11 hours, because the total time for reaching MODE 4 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, TR 3.0.3 provides actions for Conditions not covered in other Requirements. The requirements of TR 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive Condition required by TR 3.0.3. The requirements of TR 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Requirements sufficiently define the remedial measures to be taken.

Exceptions to TR 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with TR 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in TR 3.3.4, "Seismic Instrumentation". TR 3.3.4 has an Applicability of "At all times". Therefore, this TR can be applicable in any or all MODES. If the TR and the Required Actions of TR 3.3.4 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Actions are the appropriate Required Actions to complete in lieu of the actions of TR 3.0.3. These exceptions are addressed in the individual Requirements.

BASES

TRs (continued)

TR 3.0.4

TR 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when a TR is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the TR would not be met, in accordance with TR 3.0.4.a, TR 3.0.4.b, or TR 3.0.4.c.

TR 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the TR not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

TR 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the TR not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities be assessed and managed. The risk assessment, for the purposes of TR 3.0.4.b, must take into account all inoperable Technical Specification or TRM equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” Revision 3. Regulatory Guide 1.160 Revision 3 endorses the guidance in Section 11 of NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” Revision 4A. These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased

(continued)

BASES

TRs

TR 3.0.4 (continued)

risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the TR would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

TR 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The TR 3.0.4.b risk assessments do not have to be documented.

TRs allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the TR, the use of the TR 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, a small subset of systems and components may be determined to be more important to risk and therefore, the use of the TR 3.0.4.b allowance will be prohibited. The TRs governing these system and components will contain Notes prohibiting the use of TR 3.0.4.b by stating that TR 3.0.4.b is not applicable.

TR 3.0.5

TR 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 Requirement is to provide an exception to TR 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of TSRs to demonstrate:

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

b. The OPERABILITY of other equipment.

(continued)

BASES

TRs

TR 3.0.5 (continued)

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the allowed TSRs. This requirement 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 TSRs.

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 a TSR 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 a TSR on another channel in the same trip system.

TR 3.0.6

TR 3.0.6 establishes an exception to TR 3.0.2 for support systems that have a TR specified in the Technical Requirements. This exception is provided because TR 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system TR be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the unit is maintained in a safe condition are specified in the support system TR's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is a TR specified for it in the Technical Requirements, the supported system(s) is required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported system’s Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' TRs' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the unit is maintained in a safe condition in the support system's Required Actions.

(continued)

BASES

TRs

TR 3.0.6 (continued)

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with TR 3.0.2.

Technical Specification 5.7.2.18, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into TR 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of TR 3.0.6.

Cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required. The cross train check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the TR in which the loss of safety function exists are required to be entered.

BASES

TSRs

TSR 3.0.1 through TSR 3.0.4 establish the general requirements applicable to all Technical Surveillance Requirements and apply at all times, unless otherwise stated.

TSR 3.0.1

TSR 3.0.1 establishes the requirement that TSRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the TR apply, unless otherwise specified in the individual TSRs. This Requirement is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with TSR 3.0.2, constitutes a failure to meet a TR.

Systems and components are assumed to be OPERABLE when the associated TSRs have been met. Nothing in this Requirement, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the TSRs; or

b. The requirements of the Surveillance(s) are known not to be met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated TR are not applicable, unless otherwise specified.

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with TSR 3.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with TSR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be

(continued)

BASES

TSRs

TSR 3.0.1 (continued)

incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

TSR 3.0.2

TSR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per . . ." interval.

TSR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the TSRs. The exceptions to TSR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Requirements. An example of where TSR 3.0.2 does not apply is a Surveillance with a Frequency of "in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions." The requirements of regulations take precedence over the TRs. The TRs cannot in and of themselves extend a test interval specified in the regulations. Therefore, there is a Note in the Frequency stating, "TSR 3.0.2 is not applicable."

As stated in TSR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per . . ." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

(continued)

BASES

TSRs

TSR 3.0.2 (continued)

The provisions of TSR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified, with the exception of surveillance required to be performed on a 31-day frequency. For surveillance performed in a 31-day frequency, the normal surveillance interval may be extended in accordance with Technical Requirement 3.0.2 cyclically as required to remain synchronized to the 13-week maintenance work schedules. This practice is acceptable based on the results of an evaluation of 31-day frequency surveillance test histories that demonstrate that no adverse failure rate changes have occurred nor would be expected to develop as a result of cyclical use of surveillance interval extensions and the fact that the total number of 31-day frequency surveillances performed in any one-year period remains unchanged.

TSR 3.0.3

TSR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with TSR 3.0.2, and not at the time that the specified Frequency was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

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

(continued)

TSR 3.0.3 (continued)

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, TSR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

TSR 3.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

(continued)

BASES

TSRs

TSR 3.0.3 (continued)

Failure to comply with specified Frequencies for TSRs is expected to be an infrequent occurrence. Use of the delay period established by TSR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, NRC Regulatory Guide 1.160, “Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” Revision 3. This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the Required Actions for the applicable TR Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable TR Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Requirement, or within the Completion Time of the ACTIONS, restores compliance with TSR 3.0.1.

(continued)

BASES

TSRs (continued)

TSR 3.0.4

TSR 3.0.4 establishes the requirement that all applicable TSRs must be met before entry into a MODE or other specified condition in the Applicability.

This TSR ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of the TR should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified condition in the Applicability when a TR is not met due to Surveillance not being met in accordance with TR 3.0.4.

However, in certain circumstances, failing to meet a TSR will not result in TSR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, train, component, device, or variable is inoperable or outside its specified limits, the associated TSR(s) are not required to be performed, per TSR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, TSR 3.0.4 does not apply to the associated TSR(s) since the requirement for the TSR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in a TSR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the TR is not met in this instance, TR 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. TSR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a TSR has not been performed within the specified Frequency, provided the requirement to declare the TR not met has been delayed in accordance with TSR 3.0.3.

The provisions of TSR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of TSR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

(continued)

BASES

TSRs

TSR 3.0.4 (continued)

The precise requirements for performance of SRs are specified such that exceptions to TSR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated TR prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the TR's Applicability, would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, "Frequency."

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 Boration Systems Flow Paths, Shutdown

BASES

BACKGROUND

The boration injection system is a subsystem of the Chemical and Volume Control System (CVCS). The CVCS regulates the concentration of chemical neutron absorber (boron) in the reactor coolant to control reactivity changes. The boration system ensures that negative reactivity control is available during each mode of facility operation. The amount of boric acid stored in the borated water sources always exceeds the amount required to borate the Reactor Coolant System (RCS) to cold shutdown concentration assuming that the control assembly with the highest reactivity worth is stuck in its fully withdrawn position. This amount of boric acid also exceeds the amount required to bring the reactor to hot shutdown and to compensate for subsequent xenon decay.

The components required to perform this function include: (1) borated water sources, (2) charging pumps, (3) safety injection pumps, (4) separate flow paths, (5) boric acid transfer pumps, and (6) an emergency power supply from OPERABLE diesel generators. The boration system Technical Requirements place limitations on the contained water volume, boron concentration, and temperature of both the Refueling Water Storage Tank (RWST) and Boric Acid Storage System. For MODES 4, 5 and 6, the boron capability is necessary to provide a sufficient SDM to compensate for xenon decay and cooldown from 350°F to 140°F. For MODES 1, 2, and 3, the boron capability is necessary to provide a sufficient SDM to compensate for xenon decay and cooldown to 200°F.

During reactor operation, changes are made in the reactor coolant boron concentration for the following conditions:

1. Reactor Startup - boron concentration must be decreased from shutdown concentration to achieve criticality.

2. Load Follow - boron concentration must be either increased or decreased to compensate for the xenon transient following a change in load.

3. Fuel Burnup - boron concentration must be decreased to compensate for fuel burnup and the buildup of fission products in the fuel.

4. Cold Shutdown - boron concentration must be increased to the cold shutdown concentration.

(continued)

BASES

BACKGROUND (continued)

Boric acid is stored in three boric acid tanks. Two boric acid transfer pumps are provided for each unit with one pump normally aligned with one boric acid tank and continuously running at low speed to provide recirculation for the boric acid system and the boric acid tank. On a demand signal by the reactor makeup control system, the boric acid transfer pumps are shifted to high speed and the pump aligned to the makeup system delivers boric acid to the suction header of the charging pumps (Ref. 1).

APPLICABLE SAFETY ANALYSES

The boration subsystem is not assumed to be OPERABLE to mitigate the consequences of a DBA or transient. In the case of a malfunction of the CVCS, which causes a boron dilution event, the response required by the operator is to close the appropriate valves in the reactor makeup system and/or stop the primary water pumps. This action is required before the shutdown margin is lost. Operation of the boration subsystem is not assumed to mitigate this event (Ref. 2). OPERABILITY of the charging pumps, the RWST, and the appropriate flow paths is required as part of the Emergency Core Cooling System (ECCS). The Technical Specifications for the ECCS address the requirements of these components.

TR

TR 3.1.1 requires at least one boron injection flow path to be OPERABLE and capable of being powered from an OPERABLE emergency power source during MODES 4, 5, and 6 in order to provide a path to accomplish (1) normal makeup, (2) chemical shim reactivity control, and (3) miscellaneous fill and transfer operations. This requirement may be achieved by meeting one of the following two conditions:

a. A flow path from an OPERABLE boric acid storage tank, through the boric acid transfer pump, through a charging pump to the RCS, or

b. A flow path from an OPERABLE RWST through a charging pump to the RCS.

BASES (continued)

APPLICABILITY

The OPERABILITY of one boron injection flow path ensures that this system is available for reactivity control while in MODES 4, 5, and 6. The APPLICABILITY statement is modified by the following Note to ensure the restrictions imposed by Technical Specification LCO 3.0.4.b are considered:

> For Mode 4, Technical Specification LCO 3.0.4.b is not applicable to ECCS high head (centrifugal charging) subsystem.

Boron injection flow paths for MODES 1, 2, and 3 are covered in Technical Requirement 3.1.2, “Boration Systems Flow Paths, Operating”.

ACTIONS

A.1 and A.2

With the Boration Systems flow path OPERABILITY requirements not met, or the Boration Systems flow path not capable of being powered by an OPERABLE emergency power source, the plant must be placed in a condition where negative reactivity addition is not required. This is accomplished by suspending all CORE ALTERATIONS and positive reactivity additions immediately. One boron injection flow path is required to meet the TR and to ensure that negative reactivity control is available during MODES 4, 5, and 6. Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition.

The immediate Completion Time is consistent with the required times for actions to be performed without delay and in a controlled manner.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.1.1.1

This surveillance verifies the temperature of the areas containing portions of the flow path from the boric acid tanks is ≥ 63°F (value does not account for instrument error). This ensures that the high concentration of boric acid in the storage tanks is not allowed to precipitate due to cooling.

The Surveillance is modified by a note stating that the surveillance is required only if a flow path from the boric acid storage tanks is required OPERABLE. The 12 hour Frequency is based on engineering experience and is reasonable considering the time required for performing the surveillance and the probability for changes in the area temperatures.

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.1.1.2

Verifying the correct alignment for manual, power operated, and automatic valves in the Boration System flow path provides assurance that the proper flow paths exist for Boration System operation. This TSR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. This TSR 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 TSR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

REFERENCES

1. Watts Bar FSAR, Section 9.3.4, “Chemical and Volume Control System.”

2. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Boration Systems Flow Paths, Operating

BASES

BACKGROUND	A description of the Boration Systems Flow Paths is provided in the Bases for Technical Requirement 3.1.1, "Boration Systems Flow Paths, Shutdown."
APPLICABLE SAFETY ANALYSES	The boration subsystem is not assumed to be OPERABLE to mitigate the consequences of a DBA or Transient. In the case of a malfunction of the Chemical and Volume Control System, which causes a boron dilution event, the response required by the operator is to close the appropriate valves in the reactor makeup system and/or stop the primary water pumps. This action is required before the shutdown margin is lost. Operation of the boration subsystem is not assumed to mitigate this event (Ref. 1). OPERABILITY of the charging pumps, the Refueling Water Storage Tank (RWST), and the appropriate flow paths is required as part of the Emergency Core Cooling System (ECCS). The Technical Specifications for the ECCS address the requirements of these components.
TR	TR 3.1.2 requires at least two boron injection flow paths to be OPERABLE during MODES 1, 2, and 3, in order to provide two redundant paths to accomplish (1) normal makeup, (2) chemical shim reactivity control, and (3) miscellaneous fill and transfer operations. This requirement may be achieved by having two of the following three flow paths OPERABLE: a. One flow path from the boric acid storage tanks, through a boric acid transfer pump, through a charging pump to the Reactor Coolant System (RCS). b. Two flow paths from the RWST, through a charging pump to the RCS.

BASES (continued)

APPLICABILITY

The OPERABILITY of two boron injection flow paths ensures that this system is available for reactivity control while in MODES 1, 2, and 3. Two flow paths are required to ensure single functional capability in the event an assumed failure renders one of the flow paths inoperable.

Boron injection flow paths for MODES 4, 5, and 6 are covered in Technical Requirement 3.1.1, "Boration Systems Flow Paths, Shutdown."

ACTIONS

A.1

If one of the required boron injection flow paths is inoperable, action must be taken to restore the required flow path to OPERABLE status. The 72 hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE flow path and reasonable time for repairs. The Completion Time is consistent with the time allowed to restore an ECCS train to OPERABLE status (See Technical Specification 3.5.2, "ECCS - Operating.").

A.2.1, A.2.2, and A.2.3

An alternative to Required Action A.1 is to place the plant in MODE 3 and borate to a SDM equivalent to $\geq$ 1% Δk/k at 200°F within 78 hours, and restore the required flow path to OPERABLE status within 246 hours. This precludes the need for a flow path for load follow and fuel burnup compensation, allowing the additional 7 days to restore two flow paths to OPERABLE status. An additional 6 hours (78 hours total) are allowed to reach MODE 3 from full power in an orderly manner and without challenging plant systems. The allowed Completion Time to reach MODE 3 is reasonable, based on operating experience.

B.1

If the required flow path cannot be restored to OPERABLE status or the Required Actions of Condition A are not met within the associated Completion Times, the unit must be placed in a MODE in which the TR does not apply. This is done by placing the unit in at least MODE 4 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, to reach required plant conditions in an orderly manner and without challenging plant systems.

BASES (continued)

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.1.2.1

This surveillance verifies the temperature of the required flow path from the boric acid tanks to be at least 63°F (value does not account for instrument error). This ensures that the high concentration of boric acid in the storage tanks is not allowed to precipitate due to cooling.

The surveillance is modified by a Note stating that the surveillance is required only if the flow path from the boric acid storage tanks is used as one of the two required flow paths. The 12 hour Frequency is based on engineering experience and is reasonable considering the time required for performing the surveillance and the probability for changes in the area temperatures.

TSR 3.1.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in the Boration System flow path provides assurance that the proper flow paths exist for Boration System operation. This TSR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. This TSR 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 TSR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

TSR 3.1.2.3

This surveillance demonstrates that each automatic valve in the flow path actuates to its required position on an actual or simulated actuation signal. The 18 month Frequency was developed considering it is prudent that this surveillance only be performed during a plant outage. This is due to the plant conditions needed to perform the TSR and the potential for unplanned plant transients if the TSR is performed with the reactor at power.

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.1.2.4

Verification that the flow path from the boric acid tanks delivers at least 35 gpm (value does not account for instrument error) to the RCS demonstrates that gross degradation of the boric acid transfer pumps, crystallization of boric acid in the system, and other hydraulic component problems have not occurred.

The 18 month Frequency was developed considering it is prudent that this surveillance only be performed during a plant outage. This is due to the plant conditions needed to perform the TSR and the potential for unplanned plant transients if the TSR is performed with the reactor at power.

REFERENCES

1. WCAP-11618, "MERITS Program-Phase II, Task 5, Criteria Application," including Addendum 1 dated April, 1989.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Charging Pump, Shutdown

BASES

BACKGROUND	A description of the Boration Systems Flow Paths, which include charging pumps, is provided in the Bases for Technical Requirement 3.1.1, "Boration Systems Flow Paths, Shutdown."
APPLICABLE SAFETY ANALYSES	The boration subsystem is not assumed to be OPERABLE to mitigate the consequences of a DBA or Transient. In the case of a malfunction of the Chemical and Volume Control System, which causes a boron dilution event, the response required by the operator is to close the appropriate valves in the reactor makeup system and/or stop the primary water pumps. This action is required before the SDM is lost. Operation of the boration subsystem is not assumed to mitigate this event (Ref. 1). OPERABILITY of the charging pumps, the refueling water storage tank, and the appropriate flow paths is required as part of the Emergency Core Cooling System (ECCS). The Technical Specifications for the ECCS address the requirements of these components. Technical Specification 3.4.12, "Cold Overpressure Mitigation System," places restrictions on maximum number of charging pumps allowed OPERABLE for overpressure concerns.
TR	TR 3.1.3 requires one charging pump in the required boron injection flow path to be OPERABLE and capable of being powered from an OPERABLE emergency power source during MODES 4, 5, and 6 in order to provide the driving force to accomplish (1) normal makeup, (2) chemical shim reactivity control, and (3) miscellaneous fill and transfer operations.

BASES (continued)

APPLICABILITY

The OPERABILITY of one charging pump in the required boron injection flow path ensures that this system is available for reactivity control while in MODES 4, 5, and 6. The APPLICABILITY statement is modified by the following Note to ensure the restrictions imposed by Technical Specification LCO 3.0.4.b are considered:

> For MODE 4, Technical Specification LCO 3.0.4.b is not applicable to ECCS high head (centrifugal charging) subsystem.

Charging pump OPERABILITY requirements for MODES 1, 2, and 3 are covered in Technical Requirement 3.1.4, "Charging Pumps, Operating."

ACTIONS

A.1 and A.2

With the required charging pump inoperable or not capable of being powered by an OPERABLE emergency power source, the plant must be placed in a condition where negative reactivity addition is not required. This is accomplished by suspending all CORE ALTERATIONS and positive reactivity additions immediately. One OPERABLE charging pump in the required boron injection flow path is required to meet the TR and to ensure that negative reactivity control is available during MODES 4, 5, and 6. Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.1.3.1

Periodic surveillance testing of charging pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is performed in accordance with the American Society of Mechanical Engineers (ASME) OM Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. SRs are specified in the Inservice Testing Program, which encompasses the ASME OM Code. The ASME OM Code provides the activities and Frequencies necessary to satisfy the requirements.

BASES (continued)

REFERENCES

1. WCAP-11618, "MERITS Program-Phase II, Task 5, Criteria Application," including Addendum 1 dated April, 1989.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Charging Pumps, Operating

BASES

BACKGROUND	A description of the Boration Systems Flow Paths is provided in the Bases for Technical Requirement 3.1.1, “Boration Systems Flow Paths, Shutdown.”
APPLICABLE SAFETY ANALYSES	The boration subsystem is not assumed to be OPERABLE to mitigate the consequences of a DBA or transient. In the case of a malfunction of the Chemical and Volume Control System (CVCS), which causes a boron dilution event, the response required by the operator is to close the appropriate valves in the reactor makeup system and/or stop the primary water pumps. This action is required before the shutdown margin is lost. Operation of the boration subsystem is not assumed to mitigate this event (Ref. 1). OPERABILITY of the charging pumps, the refueling water storage tank, and the appropriate flow paths is required as part of the Emergency Core Cooling System (ECCS). The Technical Specifications for the ECCS address the requirements of these components.
TR	TR 3.1.4 requires at least two charging pumps to be OPERABLE during MODES 1, 2, and 3 in order to assure redundant pumps to the two redundant flow paths to accomplish (1) normal makeup, (2) chemical shim reactivity control, and (3) miscellaneous fill and transfer operations.
APPLICABILITY	The OPERABILITY of two charging pumps ensures that the CVCS system is available for reactivity control while in MODES 1, 2, and 3. Two charging pumps are required to ensure single functional capability in the event an assumed failure renders one of the pumps inoperable. Charging pump OPERABILITY requirements for MODES 4, 5, and 6 are covered in Technical Requirement 3.1.3, “Charging Pumps, Shutdown.”

BASES (continued)

ACTIONS

A.1

If one of the required charging pumps is inoperable, action must be taken to restore a required charging pump to OPERABLE status. The 72-hour Completion Time was developed taking into account the redundant capabilities afforded by the OPERABLE charging pump and reasonable time for repairs. The Completion Time is consistent with the time allowed to restore an ECCS train or to restore a boron injection flow path to OPERABLE status (See Technical Specification 3.5.2, "ECCS - Operating" and Technical Requirement 3.1.2, "Boration Systems Flow Paths, Operating.").

A.2.1, A.2.2, and A.2.3

An alternative to Required Action A.1 is to place the plant in MODE 3 and borate to a SDM equivalent to $\geq$ 1% $\Delta k/k$ at 200°F within 78 hours, and restore the required charging pump to OPERABLE status within 246 hours. This precludes the need for a flow path/charging pump for load follow and fuel burnup compensation, allowing the additional 7 days to restore two charging pumps to OPERABLE status. An additional 6 hours (78 hours total) are allowed to reach MODE 3 from full power in an orderly manner and without challenging plant systems. The allowed Completion Time to reach MODE 3 is reasonable, based on operating experience.

B.1

If two charging pumps cannot be restored to OPERABLE status or the Required Actions of Condition A are not met within the associated Completion Times, the plant must be placed in a MODE in which the TR does not apply. This is done by placing the plant in at least MODE 4 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions in an orderly manner and without challenging plant systems.

BASES (continued)

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.1.4.1

Periodic surveillance testing of charging pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is performed in accordance with the American Society of Mechanical Engineers (ASME) OM Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. SRs are specified in the Inservice Testing Program, which encompasses the ASME OM Code. The ASME OM Code provides the activities and Frequencies necessary to satisfy the requirements.

REFERENCES

1. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Borated Water Sources, Shutdown

BASES

BACKGROUND	A description of the Boration System Flow Paths, which include borated water sources is provided in the Bases for Technical Requirement 3.1.1, "Boration System Flow Paths, Shutdown."
APPLICABLE SAFETY ANALYSES	The boration subsystem is not assumed to be OPERABLE to mitigate the consequences of a DBA or transient. In the case of a malfunction of the Chemical and Volume Control System which causes a boron dilution event, the response required by the operator is to close the appropriate valves in the reactor makeup system and/or stop the primary water pumps. This action is required before the SDM is lost. Operation of the boration subsystem is not assumed to mitigate this event (Ref. 1). OPERABILITY of the charging pumps, the Refueling Water Storage Tank (RWST), and the appropriate flow paths is required as part of the Emergency Core Cooling System (ECCS). The Technical Specifications for the ECCS address the requirements of these components.
TR	TR 3.1.5 requires at least one borated water source to be OPERABLE during MODES 4, 5, and 6 to accomplish (1) normal makeup, (2) chemical shim reactivity control, and (3) miscellaneous fill and transfer operations. This requirement may be achieved by one of the following being OPERABLE as required by TR 3.1.1: a. A Boric Acid Storage System (BASS); or b. The RWST.
APPLICABILITY	The OPERABILITY of one borated water source in the required boron injection flow path ensures that this system is available for reactivity control while in MODES 4, 5, and 6. Borated water source OPERABILITY requirements for MODES 1, 2, and 3 are covered in Technical Requirement 3.1.6, "Borated Water Sources, Operating."

BASES (continued)

ACTIONS

A.1 and A.2

If the required borated water source is inoperable, the plant must be placed in a condition where negative reactivity addition is not required. This is accomplished by suspending all CORE ALTERATIONS and positive reactivity additions immediately. One borated water source is required to meet the TR and to ensure that negative reactivity control is available during MODES 4, 5, and 6. Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition.

The immediate Completion Time is consistent with the required times for actions requiring prompt attention.

TECHNICAL SURVEILLANCE REQUIREMENTS

The Notes in the Technical Surveillance Requirements state that TSR 3.1.5.1, TSR 3.1.5.2, and TSR 3.1.5.3 are only required to be performed if the RWST is the required borated water source, and TSR 3.1.5.4, TSR 3.1.5.5, and TSR 3.1.5.6 are only required to be performed if the BASS is the required borated water source.

TSR 3.1.5.1

This surveillance requires verification every 24 hours that the RWST temperature is greater than or equal to 60°F (value does not account for instrument error). The Frequency of 24 hours for performance of the surveillance is frequent enough to identify a temperature change that would approach the 60°F temperature limit and has been shown to be acceptable through operating experience. The TSR is modified by a Note which eliminates the requirement to perform this surveillance when ambient air temperature is greater than or equal to 60°F. With ambient air temperature greater than 60°F, the RWST solution temperature should not decrease below this limit, therefore, monitoring is not required.

TSR 3.1.5.2

This surveillance requires verification every 7 days that the boron concentration of the RWST is ≥ 3,100 ppm. This boron concentration is sufficient to provide an adequate SDM and also ensure a pH value between 7.5 and 10.0. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components. Since the RWST volume is normally stable, a 7-day Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.1.5.3

This surveillance requires verification every 7 days that the RWST borated water volume is ≥ 62,900 gallons (value does not account for instrument error). This borated water volume is sufficient to provide an adequate SDM and also ensure a pH value between 7.5 and 10.0. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components. Since the RWST volume is normally stable, a 7-day Frequency to verify borated water volume is appropriate and has been shown to be acceptable through operating experience. The 62,900 gallon volume requirement includes 11,400 gallons for shutdown margin and adjustments for minimum safety limit level in the RWST.

TSR 3.1.5.4

This surveillance requires verification every 24 hours that the Boric Acid Tank (BAT) solution temperature is ≥ 63°F (value does not account for instrument error). This ensures that the concentration of boric acid in the BAT is not allowed to precipitate due to cooling. The frequency of 24 hours for performance of the surveillance is frequent enough to identify a temperature change that would approach the 63°F temperature limit.

TSR 3.1.5.5

This surveillance requires verification every 7 days that the boron concentration of the BAT is between 6,120 ppm and 6,990 ppm. This boron concentration is sufficient to provide an adequate SDM and also ensure a pH value between 7.5 and 10.0. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components. Since the BAT volume is normally stable, a 7-day Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.

TSR 3.1.5.6

This surveillance requires verification every 7 days that the BAT borated water volume is ≥ 5,300 gallons (value does account for instrument error). This borated water volume is sufficient to provide an adequate SDM and also ensure a pH value between 7.5 and 10.0. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components. Since the BAT volume is normally stable, a 7-day Frequency to verify borated water volume is appropriate and has been shown to be acceptable through operating experience.

BASES (continued)

REFERENCES

1. WCAP-11618, "MERITS Program-Phase II, Task 5, Criteria Application," including Addendum 1 dated April, 1989.

2. TVA Calculation, EPM-PDM-071197, Revision 6, “Boric Acid Concentration Analysis for BAT and RWST.”

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Borated Water Sources, Operating

BASES

BACKGROUND	A description of the Boration System Flow Paths, which include borated water sources is provided in the Bases for Technical Requirement 3.1.1, "Boration System Flow Paths, Shutdown."
APPLICABLE SAFETY ANALYSES	The boration subsystem is not assumed to be OPERABLE to mitigate the consequences of a DBA or transient. In the case of a malfunction of the Chemical and Volume Control System, which causes a boron dilution event, the automatic response, or that required by the operator, is to close the appropriate valves in the reactor makeup system. This action is required before the SDM is lost. Operation of the boration subsystem is not assumed to mitigate this event (Ref. 1). OPERABILITY of the charging pumps, the RWST, and the appropriate flow paths is required as part of the Emergency Core Cooling System (ECCS). The Technical Specifications for the ECCS address the requirements of these components.
TR	TR 3.1.6 requires a Boric Acid Storage System (BASS) and the Refueling Water Storage Tank (RWST) to be OPERABLE as required by TR 3.1.2. This is a requirement during MODES 1, 2, and 3 to accomplish (1) normal makeup, (2) chemical shim reactivity control, and (3) miscellaneous fill and transfer operations.
APPLICABILITY	The OPERABILITY of borated water sources (as required by TR 3.1.2) in the required boron injection flow paths ensures that this system is available for reactivity control while in MODES 1, 2, and 3. Borated water source OPERABILITY requirements for MODES 4, 5 and 6 are covered in Technical Requirement 3.1.5, "Borated Water Sources, Shutdown."

BASES (continued)

ACTIONS

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

With the BASS inoperable, action must be taken to restore the BASS to OPERABLE status within 72 hours. The Completion Time of 72 hours to perform Required Action A.1 is reasonable based upon the typical time necessary to effect repairs and the redundant capabilities afforded by the OPERABLE borated water source.

If the BASS cannot be restored to OPERABLE status the plant must be placed in a MODE in which the requirement does not apply. This is done by placing the plant in at least MODE 3 and by borating to a SDM equivalent to at least 1% $\Delta k/k$ at 200°F in 6 additional hours (78 hours total time). It is also required that the BASS be restored to OPERABLE status in an additional 7 days (246 hours total time).

The 6 additional hours to perform Required Actions A.2.1 and A.2.2 are reasonable and based on operating experience to reach MODE 3 and the required SDM from full power operation in an orderly manner and without challenging plant systems. The 7 day Completion Time per Required Action A.2.3 is based on the low probability of an event occurring during this time period, and the consideration that the remaining borated water sources can provide the required capability.

B.1

If the Required Actions and associated Completion Times of Condition A are not met, the plant must be placed in a MODE in which the TR does not apply. This is done by placing the plant in MODE 4 within 6 hours. The allowed Completion Time is reasonable and based on operating experience to reach required plant conditions in an orderly manner and without challenging plant systems.

C.1

With the RWST boron concentration or borated water temperature not within limits, action must be taken within 8 hours to restore the RWST to OPERABLE status. This 8 hour limit was developed considering the time required to change either the boron concentration or water temperature. The Completion Time is consistent with Technical Specification 3.5.4, “Refueling Water Storage Tank.”

(continued)

BASES

ACTIONS (continued)

D.1

With the RWST inoperable for reasons other than Condition C (e.g., water volume), it must be restored to OPERABLE status within 1 hour. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting two of the boration system flow paths. The Completion Time is consistent with Technical Specification 3.5.4, "Refueling Water Storage Tank."

E.1 and E.2

If the Required Actions and associated Completion Times of Condition C or D are not met, the plant must be placed in a MODE in which the TR does not apply. This is done by placing the plant in MODE 3 within 6 hours and in MODE 4 within 12 hours. The allowed Completion Time is reasonable and based on operating experience to reach required plant conditions in an orderly manner and without challenging plant systems.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.1.6.1

The limits assumed in the accident analysis band for the RWST borated water temperature are ≥ 60°F and ≤ 105°F (values do not account for instrument error). This surveillance requires verification of the water temperature limits every 24 hours. This is frequent enough to identify a temperature change that would approach either temperature limit and has been shown to be acceptable through operating experience.

The TSR is modified by a Note which eliminates the requirement to perform this surveillance when ambient air temperatures are within the operating limits of the RWST. With ambient air temperatures within the band, the RWST solution temperature should not exceed the limits.

TSR 3.1.6.2

This surveillance requires verification every 7 days that the boron concentration of the RWST is within the required band. This ensures the reactor will remain subcritical following a LOCA. Further, it assures that the resulting sump pH will be maintained in an acceptable range so that boron precipitation in the core will not occur and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. Since the RWST volume is normally stable, a 7 day Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.1.6.3

This surveillance requires verification every 7 days that the RWST borated water volume is within the required limit of ≥ 370,000 gallons (value does not account for instrument error). This will ensure that a sufficient initial supply is available for injection and to support continued ECCS and Containment Spray System pump operation on recirculation. Since the RWST volume is normally stable, a 7 day Frequency to verify borated water volume is appropriate and has been shown to be acceptable through operating experience.

TSR 3.1.6.4

This surveillance requires verification every 24 hours that the Boric Acid Tank (BAT) solution temperature is ≥ 63°F (value does not account for instrument error). This ensures that the concentration of boric acid in the BAT is not allowed to precipitate due to cooling. The Frequency of 24 hours for performance of the surveillance is frequent enough to identify a temperature change that would approach the 63°F temperature limit and has been shown to be acceptable through operating experience.

This surveillance has been modified by a NOTE stating that the surveillance is only required if the BAT is used as one of the required borated water sources for TR 3.1.2.

TSR 3.1.6.5

This surveillance requires verification every 7 days that the boron concentration of the BAT is in accordance with Figure 3.1.6 of TR 3.1.6. This boron concentration is sufficient to provide an adequate SDM and also ensure a pH value between 7.5 and 10.0. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components. Since the BAT volume is normally stable, a 7 day sampling Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.

This surveillance has been modified by a NOTE stating that the surveillance is only required if the BAT is used as one of the required borated water sources for TR 3.1.2.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.1.6.6

This surveillance requires verification every 7 days that the BAT borated water volume is in accordance with Figure 3.1.6 (the values listed on the figure do not account for instrument error). This borated water volume at the boron concentration specified in TSR 3.1.6.5 is sufficient to provide an adequate SDM. Since the BAT volume is normally stable, a 7 day Frequency to verify borated water volume is appropriate and has been shown to be acceptable through operating experience.

This surveillance has been modified by a NOTE stating that the surveillance is only required if the BAT is used as one of the required borated water sources for TR 3.1.2.

The maximum expected boration capability requirement occurs near EOL from full power peak xenon conditions and requires borated water from a boric acid tank in accordance with Figure 3.1.6, and additional makeup from either (1) the common boric acid tank and/or batching tank, or (2) a maximum of 23,000 gallons of 3,100 ppm borated water from the refueling water storage tank. With the refueling water storage tank as the only borated water source, a maximum of 62,000 gallons of 3,100 ppm borated water is required.

REFERENCES

1. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989.

2. TVA Calculation, EPM-PDM-071197, Revision 6, “Boric Acid Concentration Analysis For BAT and RWST.”

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Position Indication System, Shutdown

BASES

BACKGROUND

Instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. TR 3.1.7 is required to ensure OPERABILITY of the control rod group demand position indicators to determine control rod positions of rod groups not fully inserted with the Reactor Trip System breakers in the closed position.

The OPERABILITY, including group demand position indication, of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. Rod position indication is required to assess OPERABILITY and misalignment. These safety analyses are not applicable to shutdown conditions. Rod Drop Times and other tests requiring control rod operability, however, are performed at shutdown. Additionally, positive reactivity addition due to rod withdrawal must be compensated for by boron addition. Rod positions are monitored and controlled when withdrawn during shutdown conditions to ensure shutdown margin is maintained. The axial position of shutdown rods and control rods is determined by the group demand position indicators.

The group demand position indicators count the pulses generated in the Rod Control System to provide a readout of the demand bank position (Ref. 1). There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The group demand position indicators are considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move 1 step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

APPLICABLE SAFETY ANALYSES

The rod Position Indication System is a system which provides information to the operator which could be used to initiate operator action. However, no DBA or transient assumes operator action to manually trip the reactor, or to take some alternative action if an automatic reactor trip does not occur (Ref. 2). Hence, the shutdown and control rods, including position indication, are not assumed to be OPERABLE to mitigate the consequences of a DBA or transient during shutdown conditions. Positive reactivity addition due to withdrawal of control rods is compensated for by boron concentration.

BASES (continued)

TR

TR 3.1.7 specifies that the group demand position indicators be OPERABLE and capable of determining within ± 2 steps the demand position for each shutdown or control rod not fully inserted. For the control rod position indicators to be OPERABLE requires meeting the surveillance requirement of the TR. This requirement provides adequate assurance that control rod position indication during shutdown conditions and rod testing is accurate, and that design assumptions are not challenged. OPERABILITY of the required position indicators ensures that inoperable, misaligned, or mispositioned control rods can be detected.

APPLICABILITY

This TR covers only the requirements on Rod Position Indication during MODES 3, 4, and 5 with the reactor trip breakers closed. Rod Position Indication during MODES 1 and 2 are covered by Technical Specification 3.1.8. In MODE 6 and in MODES 3, 4, and 5 with trip breakers open or all rods on the bottom, Rod Position Indication is not required to be OPERABLE. Rod Position Indication OPERABILITY is required only when rods are withdrawn from fully inserted.

ACTIONS

A.1

With one or more group demand position indicators inoperable, the plant must be placed in a condition where the demand position indicators are not required. This is accomplished by opening the reactor trip breakers immediately.

The immediate Completion Time is consistent with the required time for actions to be pursued without delay and in a controlled manner.

BASES (continued)

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.1.7.1

Exercising rods at a Frequency of 31 days allows the operator to determine that all withdrawn rods, including the group step counter demand position indicator, continue to be OPERABLE. A movement of 10 steps is adequate to demonstrate motion and verify a corresponding step change in the group step counter demand position indicator.
Four hours is provided to perform the first surveillance after closing the reactor trip breakers if the surveillance has not been performed within the previous 31 days. The 31-day Frequency takes into consideration other information available to the operator in the control room and the remote likelihood that rods would be withdrawn from fully inserted for extended periods of time during shutdown conditions.

REFERENCES

1. Watts Bar FSAR, Section 4.2.3 "Reactivity Control System."

2. WCAP-11618, "MERITS Program-Phase II, Task 5, Criteria Application," including Addendum 1 dated April, 1989.

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Trip System (RTS) Instrumentation

BASES

BACKGROUND

A reactor trip signal acts to open two trip breakers connected in series, feeding power to the control rod drive mechanisms. The loss of power to the mechanism coils causes the mechanisms to release the rod cluster control assemblies which then fall by gravity into the core. There are various instrumentation delays associated with each trip function, including delays in signal actuation, in opening the trip breakers, and in the release of the rods by the mechanisms. The total delay to trip is defined as the time delay from the time that trip conditions are reached to the time the rods are free and begin to fall (Ref. 1). Furthermore, RTS RESPONSE TIME is defined as the time required for the reactor trip (i.e., the time the rods are free and begin to fall) to be initiated following a step change in the variable being monitored from at least five percent below (or above) to at least five percent above (or below) the trip setpoint (Ref. 2). This definition has been clarified in the Technical Specifications. Limiting trip setpoints assumed for each trip function are given in Reference 1.

The difference between the limiting trip setpoint assumed for the analysis and the nominal trip point represents an allowance for instrumentation channel error and setpoint error. During plant startup tests, it is demonstrated that actual instrument time delays are equal to or less than the assumed values. Additionally, protection system channels are calibrated and instrument response times determined periodically in accordance with the plant Technical Specifications and this Technical Requirement.

APPLICABLE SAFETY ANALYSES

The RTS functions to maintain the SLs during all Anticipated Operational Occurrences (AOOs) and mitigates the consequences of DBAs in all MODES in which the Reactor Trip Breakers are closed.

Each of the analyzed accidents and transients can be detected by one or more RTS functions. The accident analyses described in Reference 3 take credit for most RTS trip functions. RTS trip functions not specifically credited in the accident analyses have an N.A. (Not Applicable) response time requirement in Table 3.3.1-1. They are qualitatively credited in the safety analyses and the NRC staff-approved licensing basis for the plant.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	These RTS trip functions may provide protection for conditions which do not require dynamic transient analysis to demonstrate function performance. These RTS trip functions may also serve as backups to RTS trip functions that were credited in the accident analysis. The safety analyses applicable to each RTS function are discussed in the bases for the Technical Specifications, B.3.3.1 (Ref. 4).
TR	OPERABILITY requirements for the RTS Instrumentation and interlocks are specified in Technical Specifications, section 3.3.1. TR 3.3.1 requires the RTS Instrumentation and interlocks of Table 3.3.1-1 of the TR to be OPERABLE with RESPONSE TIMES as shown in the table. RESPONSE TIMES must be within the specified limits for the affected instruments to be considered OPERABLE.
APPLICABILITY	Applicable MODES for the specific RTS Instrumentation and interlocks are delineated in Table 3.3.1-1 of Reference 4. The bases for Applicability of each function is included in Reference 4.
ACTIONS	A.1 The Required Actions for inoperable instruments are found in Reference 4. With one or more RESPONSE TIMES outside the specified limits, the affected instrument(s) must be considered inoperable and the appropriate Action referenced in Table 3.3.1-1 of Reference 4 must be taken. The bases for these actions is found in Reference 4.

BASES (continued)

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.3.1.1

TSR 3.3.1.1 demonstrates that the RTS RESPONSE TIME of each reactor trip function is within the limits listed in Table 3.3.1-1 of the TR. This ensures that the time delays assumed in the safety analyses are not exceeded. Each train's response must be verified every 18 months on a STAGGERED TEST BASIS (e.g., Train A at 18 months after initial startup, Train B at 36 months, and then Train A again). Response times cannot be determined during plant operation because equipment operation is required to measure response times. Experience has shown that these components usually pass this surveillance when performed on the 18-month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

Table 3.3.1-1 of this TR specifies the RESPONSE TIMES for the RTS.

REFERENCES

1. Watts Bar FSAR, Section 15.1.3. “Trip Points and Time Delays To Trip Assumed in Accident Analyses.”

2. Watts Bar FSAR, Section 7.0 “Instrumentation and Controls.”

3. Watts Bar FSAR, Section 15.0 “Accident Analyses.”

4. Watts Bar Technical Specifications (Unit 2), Section 3.3.1, “Reactor Trip Instrumentation,” and Bases for 3.3.1.

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Features Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based upon the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents. A detailed Background for ESFAS is given in Reference 1. This TR covers only RESPONSE TIME testing.

The ESFAS RESPONSE TIME is defined as the interval required for the ESF sequence to be initiated subsequent to the time that the appropriate variables exceed the setpoints. This definition is augmented in the Standard Technical Specifications to include automatic system lineups and diesel generator starting and sequence loading delays. The ESF sequence is initiated by the output of the ESFAS, which is by the operation of the dry contacts of the slave relays (600 series relays) in the output cabinets of the Solid State Protection System (SSPS). The RESPONSE TIMES listed in Table 3.3.2-1 of this TR include the interval of time which will elapse between the time the parameter as sensed by the sensor exceeds the safety setpoint and the time the SSPS slave relay dry contacts are operated. The values listed are maximum allowable values consistent with the safety analyses and this Technical Requirement and are systematically verified during plant preoperational startup tests. For channels that include dynamic transfer functions (e.g., lag, lead/lag, rate/lag, etc.), the response time test may be performed with the transfer functions set to one with the resulting measured response time compared to the appropriate FSAR response time. Alternately, the response time test can be performed with the time constants set to their nominal value provided the required response time is analytically calculated assuming the time constants are set at their nominal values. The response time may be measured by a series of sequential tests such that the entire response time is measured. The overall ESFAS RESPONSE TIMES are listed in this TR.

The ESFAS is always capable of having response time tests performed using the same methods as those tests performed during the preoperational test program or following significant component changes (Ref. 2).

BASES (continued)

APPLICABLE SAFETY ANALYSES	The required channels of ESFAS Instrumentation provide plant protection in the event of any of the analyzed accidents. The accident analyses described in Reference 3 take credit for operation of ESF systems during DBAs. The safety analyses applicable to each ESFAS function are discussed in the bases for the Technical Specifications, B 3.3.2 (Ref. 1), B 3.3.5 (Ref. 4) and B 3.3.6 (Ref. 5).
TR	OPERABILITY requirements for ESFAS Instrumentation are specified in Technical Specifications, LCOs 3.3.2, 3.3.5 and 3.3.6. TR 3.3.2 requires the ESFAS Instrumentation of Table 3.3.2-1 of the TR to be OPERABLE with RESPONSE TIMES as shown in the table. RESPONSE TIMES must be within the specified limits for the affected instruments to be considered OPERABLE.
APPLICABILITY	Applicable MODES for the specific ESFAS Instrumentation are delineated in Table 3.3.2-1 of Reference 1; in the Applicability of Reference 4; and in Table 3.3.6-1 of Reference 5. The bases for Applicability of each function are included in References 1, 4, 5, and 6.
ACTIONS	A.1 The required Actions for inoperable instruments are found in Reference 1. With one or more RESPONSE TIMES outside the specified limits, the affected instrument(s) must be considered inoperable and the appropriate Action referenced in Table 3.3.2-1 of Reference 1; the Actions of Reference 4; or the appropriate Action of Table 3.3.6-1, must be taken. The bases for these actions are found in References 1, 4, 5, and 6.

BASES (continued)

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.3.2.1

TSR 3.3.2.1 demonstrates that the ESFAS RESPONSE TIME of each ESFAS function is within the limits listed in Table 3.3.2-1 of the TR. This ensures that the time delays assumed in the safety analyses are not exceeded. Response time tests are conducted on an 18 month STAGGERED TEST BASIS. The 18 month Frequency was developed considering it was prudent that these Surveillances only be performed during a plant outage. This was due to the plant conditions needed to perform the Surveillance and the potential for unplanned plant transients if the Surveillance is performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed on the 18 month Frequency.

Table 3.3.2-1 of this TR specifies the RESPONSE TIMES for the ESFAS Instrumentation.

REFERENCES

1. Watts Bar Technical Specifications (Unit 2), Section 3.3.2, “Engineered Safety Features Actuation System Instrumentation,” and Bases for 3.3.2.

2. Watts Bar FSAR, Section 7.3.1.2.6, “Minimum Performance Requirements.”

3. Watts Bar FSAR, Section 15.0 “Accident Analyses.”

4. Watts Bar Technical Specifications (Unit 2), Section 3.3.5, “LOP Diesel Generator Start Instrumentation,” and Bases for 3.3.5.

5. Watts Bar Technical Specifications (Unit 2), Section 3.3.6, “Containment Vent Isolation Instrumentation,” and Bases for 3.3.6.

6. Westinghouse Letter, WAT-D-11264, “Tennessee Valley Authority Watts Bar Nuclear Plant Containment Spray Delay Time Increase,” dated August 13, 2004.

B 3.3 INSTRUMENTATION

B 3.3.3 RESERVED FOR FUTURE ADDITION

B 3.3 INSTRUMENTATION

B 3.3.4 Seismic Instrumentation

BASES

BACKGROUND

The seismic instrumentation is common to both units and is made up of several instruments such as accelerometers, an accelerograph, recorders, etc. These instruments are placed in several appropriate locations throughout the plant in order to provide data on the seismic input to containment, data on the frequency, amplitude and phase relationship of the seismic response of the containment structure, and data on the seismic input to other Seismic Category I structures (Ref. 1).

The seismic instrumentation is used to promptly determine the nature and severity of a seismic event and to predict the impact (i.e., potential for damage) on nuclear power plant features which are important to safety. This is required to permit comparison of the measured response to that used in the design basis for the unit to determine if plant shutdown is required pursuant to Appendix A of 10 CFR Part 100. The instrumentation is consistent with the recommendations of Reference 1.

The original seismic instrumentation was replaced with state of the art digital instrumentation in order to permit application of EPRI OBE exceedance criteria delineated in References 4 and 5. Use of these criteria is permitted by Reference 6 provided that upgraded instrumentation is used. The replacement instrumentation is capable of recording a seismic event and performing appropriate analyses of the recorded data to provide an immediate basis for determining whether an OBE exceedance has occurred. Reference 6 directs that this information must be evaluated within 4 hours after an event and a walkdown of critical plant features must be accomplished within 8 hours after an event in order to make a determination as to whether a plant shutdown is warranted.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the seismic instrumentation ensures that sufficient capability is available to promptly determine the magnitude of a seismic event and to determine the impact on those features important to safety. This capability is required to permit comparison of the measured response to that used in the design basis for the unit to determine if plant equipment inspection is required pursuant to Appendix A of 10 CFR Part 100 prior to restart. Seismic risks which appear as dominant sequences in PRAs occur for very severe earthquakes with magnitudes which are a factor of two or three above the Safe Shutdown Earthquake and Design Basis Earthquake. The Seismic Instrumentation System was not designed to function or to provide comparative information for such severe earthquakes. This instrumentation is more pertinent to determining the need to shut down following a seismic event and the ability to restart the plant after seismic events which are not risk contributors, and is therefore not of prime importance in risk dominant sequences (Refs. 2 & 8).

TR

TR 3.3.4 requires that the seismic monitoring instrumentation which is shown in Table 3.3.4-1 shall be OPERABLE. This requirement ensures that an assessment can be made of the effects on the plant of earthquakes which may occur that exceed the design basis spectra for the Operating Basis Earthquake (Ref. 3).

APPLICABILITY

Since the possibility of earthquakes is not MODE dependent, OPERABILITY of the seismic instrumentation is required at all times. The Applicability has been modified by a Note stating that the provisions of TR 3.0.3 do not apply.

ACTIONS

A.1

The determination as to whether an OBE exceedance has occurred is made by comparing the calculated spectra for the event with the applicable design basis spectra for that building and location. Reference 6 requires that this determination be made considering the data from instruments located on the Containment foundation. Therefore, the exceedance determination for WBN will be made using event data from 0-XT-52-75A in the Containment annulus. Data from this instrument is recorded at panel 0-R-113, which also contains the computer used to calculate the spectral content and the alarm panel used to annunciate in the control room. These devices are the key components used to detect

(continued)

BASES

ACTIONS

A.1 (continued)

the event and make a shutdown determination. With one or more of these required seismic monitoring instruments inoperable for more than 30 days, the inoperability of the instruments must be documented in accordance with the Corrective Action Program.

With one or more of the remaining seismic instruments inoperable for more than 60 days, the inoperability of the instruments must be documented in accordance with the Corrective Action Program. A longer period of inoperability is allowed for these instruments since they are used only for evaluating plant condition following an event and not for input to the shutdown decision.

B.1, B.2, and B.3

When one or more seismic monitoring instruments actuate during a seismic event with greater than or equal to 0.01g ground acceleration, all of the Required Actions under Condition B must be completed. The data retrieved from the actuated instruments must be analyzed to determine the magnitude of the vibratory ground motion. The replacement digital instrumentation provides the capability to analyze the event data onsite and generate event spectra to be used in determining whether an OBE exceedance has occurred. If an OBE exceedance has occurred, Reference 6 directs that this evaluation should occur within 4 hours after the event. Reference 6 also requires performance of a limited scope walkdown per Reference 7 to determine the extent of actual damage within 8 hours following the event. The information provided by this walkdown and the spectral analysis are to be used in making a determination as to whether to proceed with plant shutdown. In addition, the seismic event must be documented in accordance with the Corrective Action Program.

B.4 and B.5

Each actuated monitoring instrument must be restored to OPERABLE status within 24 hours. Within 10 days of the actuation, a CHANNEL CALIBRATION must be performed on each actuated monitoring instrument. The Completion Time of 10 days to perform Required Action B.2 is reasonable and is based on engineering judgment.

(continued)

BASES

ACTIONS (continued)

B.6

Subsequent analysis must then be performed using data from the remaining seismic monitoring instruments to evaluate the plant response in comparison with previously generated design basis spectra at the locations of those instruments. The Completion Time of 14 days to perform Required Action B.6 is reasonable and based upon the typical time necessary to analyze data.

TECHNICAL SURVEILLANCE REQUIREMENTS

The TSRs for each seismic monitoring Function are identified by the SRs column of Table 3.3.4-1.

A Note has been added to the TSRs to clarify that Table 3.3.4-1 determines which SRs apply to which seismic monitoring instruments.

TSR 3.3.4.1

Performance of a CHANNEL CHECK on the seismic instrumentation once every 31 days ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is a check of external system status indications that the seismic monitoring equipment is in a state of readiness to properly function should an earthquake occur. A CHANNEL CHECK will detect gross system failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL OPERATIONAL TEST.

The Surveillance Frequency of 31 days is based on operating experience related to instrumentation systems, which demonstrates that gross instrumentation system failure in any 31 day interval is a rare event. The CHANNEL CHECK supplements the loss of power annunciation for the equipment in the auxiliary instrument room. The equipment in the auxiliary control room does not have a loss of power alarm but only provides supplemental data.

TSR 3.3.4.2

A CHANNEL OPERATIONAL TEST is to be performed on each required channel to ensure the entire channel will perform the intended function. A CHANNEL OPERATIONAL TEST is the comparison of the response of the instrumentation, including all components of the instrument, to a known signal. Although the seismic trigger is functionally checked, its setpoint is not verified. The 184 day Surveillance Frequency is based upon the known reliability of the monitoring instrumentation and has been shown to be acceptable through operating experience.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.3.4.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor by comparing the response of the instrument to a known input on the sensor. This test verifies the capability of the seismic instrumentation to correctly determine the magnitude of a seismic event and evaluate the response of those features important to safety. The 18 month Surveillance Frequency is based upon operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. Regulatory Guide 1.12, “Instrumentation for Earthquakes,” Revision 1, April 1974.

2. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 8.

3. Watts Bar FSAR, Section 3.7.4, “Seismic Instrumentation Program.”

4. EPRI NO-5930, July 1988, “A Criterion for Determining Exceedance of the Operating Basis Earthquake.”

5. EPRI TR-104239, June 1994, “Seismic Instrumentation in Nuclear Power Plants for Response to OBE Exceedance: Guideline for Implementation.”

6. Regulatory Guide 1.166, “Pre-Earthquate Planning And Immediate Nuclear Power Plant Operator Post-Earthquake Actions,” Revision 0, March 1997.

7. EPRI NP-6695, December 1989, “Guidelines for Nuclear Plant Response to an Earthquake.”

8. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM),” dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.3 INSTRUMENTATION

B 3.3.5 RESERVED FOR FUTURE ADDITION

B 3.3 INSTRUMENTATION

B 3.3.6 Loose-Part Detection System

BASES

BACKGROUND

The Loose-Part Detection System consists of 12 sensors, a system cabinet, alarm units, and an audio monitor. The sensors are located in the six natural collection regions. These regions consist of the top and bottom plenums of the reactor vessel and the primary coolant inlet plenum to each steam generator. The entire system is described in Reference 1.

The Loose-Part Detection System provides the capability to detect acoustic disturbances indicative of loose parts within the Reactor Coolant System (RCS) pressure boundary. This system is provided to avoid or mitigate damage to RCS components that could occur from these loose parts. The Loose-Part Detection System Technical Requirement is consistent with the recommendations of Reference 2.

APPLICABLE SAFETY ANALYSES

The presence of a loose part in the RCS can be indicative of degraded reactor safety resulting from failure or weakening of a safety-related component. A loose part, whether it is from a failed or weakened component, or from an item inadvertently left in the primary system during construction, refueling, or maintenance, can contribute to component damage and material wear by frequent impacting with other parts in the system. Also, a loose part increases the potential for control-rod jamming and for accumulation of increased levels of radioactive crud in the primary system (Ref. 2).

The Loose-Part Detection System provides the capability to detect loose parts in the RCS which could cause damage to some component in the RCS. Loose parts are not assumed to initiate any DBA, and the detection of a loose part is not required for mitigation of any DBA (Refs. 3 & 4).

TR

TR 3.3.6 requires the Loose-Part Detection System to be OPERABLE. This is necessary to ensure that sufficient capability is available to detect loose metallic parts in the RCS and avoid or mitigate damage to the RCS components. This requirement is provided in Reference 2.

BASES (continued)

APPLICABILITY

TR 3.3.6 is required to be met in MODES 1 and 2 as stated in Reference 2. These MODES of applicability are provided in Reference 2.

The Applicability has been modified by a Note stating that the provisions of TR 3.0.3 do not apply.

ACTIONS

A.1

With one or more Loose-Part Detection System channels inoperable for more than 30 days, document the inoperability of the channel in accordance with the Corrective Action Program.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.3.6.1

Performance of a CHANNEL CHECK for the Loose-Part Detection System once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or of even something more serious. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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

The Surveillance and the Surveillance Frequency are provided in Reference 2.

TSR 3.3.6.2

A CHANNEL OPERATIONAL TEST is to be performed every 31 days on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the Loose-Part Detection System to detect impact signals which would indicate a loose part in the RCS. The Surveillance and the Surveillance Frequency are provided in Reference 2.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.3.6.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The 18 month Surveillance Frequency is based upon operating experience and is consistent with the typical industry refueling cycle. The Surveillance and the Surveillance Frequency are provided in Reference 2. Reference 1 describes the use of a computer-based analytical system to verify proper channel calibration. This is an acceptable option to using a mechanical impact device for sensors located in plant areas where plant personnel radiation exposure is considered by Plant Management to be excessive.

REFERENCES

1. Watts Bar FSAR, Section 7.6.7, “Loose Part Monitoring System (LPMS) System Description.”

2. Regulatory Guide 1.133, “Loose-Part Detection Program for the Primary System of Light-Water-Cooled Reactors.”

3. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 4.

4. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM),” dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.3 INSTRUMENTATION

B 3.3.7 RESERVED FOR FUTURE ADDITION

B 3.3 INSTRUMENTATION

B 3.3.8 Hydrogen Monitor

BASES

BACKGROUND

A Hydrogen Monitor is provided to detect high hydrogen concentration conditions that represent a potential for containment breach from a hydrogen explosion. This variable is also useful in verifying the adequacy of postaccident mitigating actions. Hydrogen concentration may also be used to determine whether or not the Hydrogen Ignitors should be started or other action taken. Containment hydrogen instrumentation has a monitoring range of 0-10% (by volume) hydrogen concentration.

By rule change in 2003, 10 CFR 50.44 (Ref. 1) no longer defined a design basis Loss of Coolant Accident (LOCA) hydrogen release, and eliminated the requirements for hydrogen control systems to mitigate such a release. The installation of Hydrogen Recombiners and/or vent and purge systems required by 50.44(b)(3) prior to revision in 2003 was intended to address the limited quantity and rate of hydrogen generation that was postulated from a design basis LOCA. The Commission found that this hydrogen release was not risk significant because the design-basis LOCA hydrogen release did not contribute to the conditional probability of a large release up to approximately 24 hours after the onset of core damage. In addition, these systems were ineffective at mitigating hydrogen releases from risk significant accident sequences that could threaten Reactor Building integrity. The Improved Standard Technical Specifications (ISTS) at the time stated that Hydrogen Recombiners met 10 CFR 50.36(c)(2)(ii) Criterion 3 (accident mitigation). As stated in the rule change, since Hydrogen Recombiners are no longer required to respond to a LOCA, the Hydrogen Recombiners no longer meet Criterion 3 or any of the other criteria for retention in the Technical Specifications (TSs). Therefore, the new rule states that the requirements related to Hydrogen Recombiners currently in the ISTS no longer meet the criteria of 10 CFR 50.36(c)(2)(ii) for retention in the TSs and may be eliminated.

With the elimination of the design-basis LOCA hydrogen release, the Hydrogen Monitors are also no longer required to mitigate design basis accidents and, therefore, the Hydrogen Monitors do not meet the definition of a safety-related component as defined in 10 CFR 50.2 (Ref. 2). Regulatory Guide (RG) 1.97 (Ref. 3) Category 1 instrumentation is intended for key variables that most directly indicate the accomplishment of a safety function for design basis accident events. The Hydrogen Monitors no longer meet the definition of Category 1 in RG 1.97. As part of the rulemaking to revise 50.44 the Commission found that Category 3,

(continued)

Bases

BACKGROUND (continued)

as defined in RG 1.97, is an appropriate categorization for the Hydrogen Monitors because the monitors are required to diagnose beyond design basis accidents. Hydrogen monitoring is not the primary means of indicating a significant abnormal degradation of the reactor coolant pressure boundary and has been found to not be risk-significant. Therefore, the rule making stated that hydrogen monitoring equipment requirements no longer meet the criteria of 50.36(c)(2)(ii) for retention in TSs and, therefore, may be removed from the TSs.

APPLICABLE SAFETY ANALYSES

As stated in the BACKGROUND section, the Hydrogen Monitor is no longer required for mitigation of design basis accidents. Based on this, the Hydrogen Monitor does not meet the definition of a safety-related component. However, the elimination of Hydrogen Recombiners in accordance with Technical Specification Task Force (TSTF)-447, Rev. 1 (Ref. 4), was contingent on each licensee maintaining the capability to monitor hydrogen concentrations in the Reactor Building during beyond design basis accidents. This TR maintains that commitment (Ref. 5).

TR

The Hydrogen Monitor is required to be OPERABLE to ensure that the necessary equipment will be available to monitor the hydrogen concentration within containment during significant beyond design-basis accident conditions (Ref. 5).

APPLICABILITY

The Hydrogen Monitor is required to be OPERABLE in MODES 1, 2 and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event that would require hydrogen monitoring is low; therefore, the monitor is not required to be OPERABLE in these MODES.

ACTIONS

A.1

Seven days to restore the hydrogen monitor capability is reasonable given the requirement to be available for use in diagnostics during a beyond design basis event.

(continued)

Bases

ACTIONS (continued)

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies that the failure to comply with the 7 day Completion Time must be documented in the Corrective Action Program so that the impact of the inoperable equipment with regard to continued plant operation may be evaluated. Consideration should be given to alternate means, such as core damage assessments performed under the Severe Accident Management Guidelines during the extended period the Hydrogen Monitor is inoperable. During normal operations the probability of occurrence of a beyond design basis accident is low and therefore, continued plant operation should not be significantly impacted. However, the actions required to restore the inoperable monitor should be pursued in a manner that is commensurate with the component's importance to safety.

TECHNICAL SURVEILLANCE REQUIREMENTS

SR 3.3.8.1

A CHANNEL CALIBRATION is performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter with the necessary range and accuracy. The Frequency is based on operating experience and consistency with the typical industry refueling cycle.

Bases (continued)

REFERENCES

1. 10 CFR 50.44, “Standards for Combustible Gas Control System in Light-Water-Cooled Power Reactors,” October 16, 2003.

2. 10 CFR 50.2, “Definition of Safety Related Structures, Systems, and Components.”

3. Regulatory Guide 1.97, Revision 2, December 1980, “Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident.”

4. TSTF-447, Revision 1, “Elimination of Hydrogen Recombiners and Change to Hydrogen and Oxygen Monitors.”

5. Commitment (NCO080031001) made in TVA’s letter dated September 4, 2008, to maintain a hydrogen monitoring system capable of diagnosing beyond design basis accidents.

6. Regulatory Guide 1.7, Revision 3, “Control of Combustible Gas Concentrations in Containment.”

B 3.3 INSTRUMENTATION

B 3.3.9 Power Distribution Monitoring System (PDMS)

BASES

BACKGROUND

The Power Distribution Monitoring System (PDMS) generates a continuous measurement of the incore power distribution using the methodology documented in Reference 1. The PDMS employs an advanced three-dimensional nodal code to calculate the incore power distribution. The reference incore power distribution is continuously normalized to the incore flux measurements from the self-powered detector elements. On a nominal once-per-minute basis, the incore power distribution is updated with self powered detector measurements and other plant instrumentation.

The PDMS incore power distribution measurement can be used to determine the most limiting core peaking factors, $F^N_{\Delta H}$, the Nuclear Enthalpy Rise Hot Channel Factor (Technical Specification 3.2.2) and $F_Q(Z)$, the Heat Flux Hot Channel Factor (Technical Specification 3.2.1). The incore power distribution measurement can also be used in the calibration of the excore neutron flux detection system (Technical Specification 3.3.1), monitoring the QUADRANT POWER TILT RATIO (QPTR) (Technical Specification 3.2.4), and verifying the position of a rod with inoperable position indicators (Technical Specification 3.1.8).

The PDMS requires information on current plant and core conditions in order to determine the core power distribution using the core peaking factor measurement and measurement uncertainty methodology described in Reference 1. The OPERABILITY of the PDMS with the specified minimum complement of instrumentation channel inputs ensures that the measurements obtained from use of this system accurately represent the spatial neutron flux distribution of the core. The PDMS requires input for average reactor vessel inlet temperature, reactor power level, control bank positions, and signals from the Self-Powered Detector (SPD) elements.

The OPERABLE PDMS is to be used for calibration of the Excore Neutron Flux Detection System and measurement of $F_Q(Z)$ or $F^N_{\Delta H}$. Similarly, the PDMS may be used for verifying the position of a rod with inoperable position indicators or monitoring the QUADRANT POWER TILT RATIO.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The PDMS is used for periodic measurement of the core power distribution to confirm operation within design limits and periodic calibration of the excore detectors. This system does not initiate any automatic protection action. The PDMS is not assumed to be OPERABLE to mitigate the consequences of a DBA or transient (References 2, 3, and 4).

TR

TR 3.3.9 requires the PDMS to be OPERABLE with the specified number of instrument channel inputs from the plant computer for each function listed in Table 3.3.9-1. The PDMS is OPERABLE when the required channel inputs are available, the calibration data set is valid, and reactor power is ≥ 25% RTP.

This TR ensures the OPERABILITY of the PDMS when required to monitor the power distribution within the core. The PDMS is used for periodic surveillance of the incore power distribution and calibration of the excore detectors. The surveillance of incore power distribution verifies that the peaking factors are within their design envelope (References 3 and 4). The peaking factor limits include measurement uncertainty which bounds the actual measurement uncertainty of an OPERABLE PDMS (Reference 1).

Maintaining the minimum number of instrumentation channel inputs ensures the uncertainty is bounded by the uncertainty methodology. Similarly, when THERMAL POWER is less than 25% RTP, then the accuracy of the adjustment provided by the Self-Powered Detector (SPD) elements to the measured PDMS power distribution may not be bounded by the uncertainties documented in Reference 1.

APPLICABILITY

The PDMS must be OPERABLE when it is used for calibration of the Excore Neutron Flux Detection System, monitoring the QPTR, measurement of $F^N_{\Delta H}$ and $F_Q(Z)$, or verifying the position of a rod with inoperable position indicators.

BASES (continued)

ACTIONS

A.1

The Required Action A.1 has been modified by a Note stating that the provisions of TR 3.0.3 do not apply.

With THERMAL Power less than 25% RTP or with one or more required channel inputs inoperable or unavailable to the PDMS, the PDMS must not be used to obtain an incore power distribution measurement. Therefore, the Required Action A.1 prohibits the use of the inoperable system for the applicable monitoring or calibration functions.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.3.9.1

Performance of the CHANNEL CHECK ensures that a gross instrumentation failure 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 two instrument channels could be an indication of excessive instrument drift in one of the channels.

A CHANNEL CHECK will detect gross channel failure, thus it is a key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

The Frequency of 24 hours is sufficient considering the PDMS provides automatic validation of the channel inputs and either discards the inoperable channel input or declares itself inoperable, but at the same time ensures that the required channel inputs to the PDMS are manually verified to be valid within a reasonable time frame prior to using the PDMS to obtain an incore power distribution measurement.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.3.9.2

Verification by administrative means of the surveillance requirements required elsewhere ensures the instrumentation channels satisfy nominal accuracy and reliability for power operation. Many of these surveillance requirements are CHANNEL CALIBRATIONS.

CHANNEL CALIBRATIONS are typically performed every 18 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATION must be performed consistent with the assumptions of the Watts Bar setpoint methodology. The difference between the current “as found” values and the previous test “as Left” values must be consistent with the drift allowance used in the setpoint methodology.

The Frequency of 18 months is based upon the assumption of an 18 month calibration interval in the determination of the magnitude of sensor/transmitter drift in the setpoint methodology.

Eight notes modify the instrumentation requirements specified in Table 3.3.9-1.

Note 1 allows up to three parameters to be used for reactor power input into PDMS, but BEACON™ will only accept two options at any one time.

Note 2 allows the control bank position input to come from either the Demand Position Indication or the average of the individual Rod Position Indications.

Note 3 clarifies that the CHANNEL CALIBRATION requirements specified in this table apply only to the RCS Loop ΔT power input.

Note 4 clarifies that the calorimetric heat balance adjustment is not applicable to the average RCS Loop ΔT power input.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.3.9.2 (continued)

Note 5 clarifies that the SR 3.3.1.10 requirements specified in this table apply only to the Narrow Range RTDs.

Note 6 clarifies that the SR 3.3.3.2 requirements specified in this table apply only to the Wide Range RTDs.

Note 7 allows the RCS Cold Leg Temperature to come from either the Narrow or Wide Range RTDs.

Note 8 allows a reduced number of SPDs subsequent to the initial incore power distribution measurement in each fuel cycle.

REFERENCES

1. WCAP-12472-P-A, "BEACON™ Core Monitoring and Operations Support System," August 1994 (Addendum 1, January 2000; Addendum 2, April 2002; and Addendum 4, 2012).

2. 10 CFR 50.46, "Acceptance criteria for emergency core cooling systems for light-water nuclear power reactors."

3. WCAP-11618, "MERITS Program-Phase II, Task 5, Criteria Application," including Addendum 1 dated April, 1989, as clarifed by Reference 4.

4. TVA letter, "Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM)," dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, "Watts Bar Technical Requirements Manual," (ADAMS Accession No. ML073620391).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Safety Valves, Shutdown

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Trip System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed pop-type, spring-loaded, self-actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is 110% of the design pressure (Ref. 1).

Because the safety valves are totally enclosed and self-actuating, they are considered independent components. The relief capacity for each valve, 420,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves or increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, 4, 5, and 6 (with the reactor vessel head on); however, in MODE 4, MODE 5 and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of Technical Specification 3.4.12, “Cold Overpressure Mitigation System (COMS).”

The upper and lower pressure limits are based on the ± 3% tolerance. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents above 350°F. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure. The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 2) could include damage to RCS components, increased LEAKAGE, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The pressurizer safety valves protect the RCS from being pressurized above the RCS pressure Safety Limit. The pressurizer safety valves provide overpressurization protection during both power operation and hot standby. However, the pressurizer safety valves are not assumed to function to mitigate a DBA or transient in MODES 4 and 5 (Refs. 3 & 5).

TR

This requirement is provided to ensure continuity in the restructuring of Standard Technical Specifications. Reactor Coolant System overpressure protection is provided in MODES 4 and 5 by the Cold Overpressure Mitigation System (COMS) covered by Technical Specification LCO 3.4.12.

Reference 4 specifies requirements which, when met, may preclude the need for this TR.

A Note modifies this TR to indicate that the lift setting of the pressurizer Code safety valves can be outside the required lift setting when in MODE 4 for the purpose of setting at hot ambient conditions. Safety valves can lift at a slightly different pressure as the valve temperature varies. Therefore, setting the safety valve for nominal operating conditions in MODE 1 may result in a lift pressure drifting outside the required tolerance limits as the plant is shutdown to MODE 5. This exception is allowed for entry and operation into and exit from MODES 4 and 5 provided a preliminary cold setting was made prior to heatup.

APPLICABILITY

The OPERABILITY of one pressurizer Code safety valve ensures that overpressure protection is provided in MODES 4 and 5. OPERABILITY of Code safety valves is not required in MODE 6. Code safety valve OPERABILITY requirements for MODES 1, 2, and 3 are covered in Technical Specification 3.4.10, “Pressurizer Safety Valves.”

ACTIONS

A.1

With no pressurizer Code safety valves OPERABLE, the plant must be placed in a condition which minimizes the risk of a pressure spike large enough to actuate a safety valve. This is done by suspending all operations involving positive reactivity changes. The immediate Completion Time for performance of Required Action A.1 shall not preclude completion of actions to establish a safe condition.

(continued)

BASES

ACTIONS (continued)

A.2

In addition to Action A.1, an OPERABLE Residual Heat Removal loop shall be placed in operation in the shutdown cooling mode. This provides overpressure protection through the Residual Heat Removal suction and discharge relief valves. The immediate Completion Time requires an operator to initiate actions to place the loop in shutdown cooling. Once actions are initiated, they must be continued until the loop is in the shutdown cooling mode.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.4.1.1

TSR 3.4.1.1 requires verification that the pressurizer safety valve is OPERABLE in accordance with the Inservice Testing Program.

REFERENCES

1. Watts Bar FSAR, Section 5.5.13, “Safety and Relief Valves.”

2. ASME Boiler and Pressure Vessel Code, Section III, NB 7000.

3. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 5.

4. Generic Letter 90-06, “Resolution of Generic Issue 70, “Power-Operated Relief Valve and Block Valve Reliability,” and Generic Issue 94, “Additional Low-Temperature Overpressure Protection for Light-Water Reactors,” Pursuant to 10 CFR 50.54(f).

5. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM),” dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Pressurizer Temperature Limits

BASES

BACKGROUND

The pressurizer is an ASME Section III, vertical vessel with hemispherical top and bottom heads constructed of carbon steel. The vessel is clad with austenitic stainless steel on all surfaces exposed to the reactor coolant. A stainless steel liner or tube may be used in lieu of cladding in some nozzles. The surge line nozzle and removable electric heaters are installed in the bottom head. Spray line nozzles, relief and safety valves are located in the top head of the vessel. A small continuous spray is provided through a manual bypass valve around the power-operated spray valves. The temperature, and hence the pressure are controlled by varying the power input to selected heater elements. The pressurizer is designed to withstand the effects of cyclic loads due to pressure and temperature changes. These loads are introduced by startup and shutdown operations, power transients and reactor trips. During startup and shutdown, the rate of temperature change is controlled by the operator. Heatup rate is controlled by the input to the heater elements, and cooldown is controlled by spray. When the pressurizer is filled with water, i.e., during initial system heatup, and near the end of the second phase of plant cooldown, Reactor Coolant System (RCS) pressure is maintained by the letdown flow rate via the Residual Heat Removal System.

These Bases address the control of the rate of change of temperature and the effect of the thermal cycling on critical areas of the pressure boundary of the pressurizer. The Reactor Coolant Pressure Boundary, which includes the pressurizer, is defined in 10 CFR 50, section 50.2 (Ref. 1). General rules for design and fabrication are provided in 10 CFR 50, section 50.55a (Ref. 2). These design and fabrication rules are based on the ASME Boiler and Pressure Vessel Code.

APPLICABLE SAFETY ANALYSES

The limits on the rate of change of temperature for the heatup and cooldown of the pressurizer are not derived from Design Basis Accident analyses (Refs. 3 & 5). The limits are prescribed during normal operation to limit the cyclic, thermal loading on critical areas in the pressure boundary. The limits on the rate of change of temperature have been established, using approved methodology, to preclude operation in an unanalyzed condition.

BASES (continued)

TR

TR 3.4.2 specifies the acceptable rates of heatup and cooldown of the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to cyclic induced failure in the pressure boundary of the pressurizer.

APPLICABILITY

The limits on the rate of change of temperature provide a definition of acceptable operation to limit cyclic temperature loading to analyzed conditions. Although these limits were developed to provide rules for operation during heatup and cooldown (MODES 3, 4, and 5), they are applicable at all times.

ACTIONS

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

If the rate of change of temperature is outside the limits, the rate of temperature change must be restored to within limits in 30 minutes. 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 corrective actions can be accomplished in this time in a controlled manner. In addition to restoring operation to within limits, an evaluation is required within 72 hours to determine if operation may continue. This may require event-specific stress analyses or inspections. A favorable evaluation must be completed before continuing operation. The 72-hour Completion Time is consistent with that allowed in Technical Specification 3.4.3, “RCS Pressure and Temperature Limits.”

A Note is provided to clarify that all Actions must be completed whenever this Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration to within limits is insufficient without the evaluation of the structural integrity of the pressure boundary of the pressurizer.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE and the pressure reduced. This will allow a more careful examination of the event. The 6-hour Completion Time is reasonable, considering operating experience, to reach MODE 3 from full power. The additional 30 hours to reduce the pressure to < 500 psig in an orderly manner also considers operating experience. This reduction in pressure is possible without challenging the plant systems or violating any operating limits.

BASES (continued)

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.4.2.1

TSR 3.4.2.1 verifies that the rate of heatup and the rate of cooldown are within limits. "Step wise" cooling must be avoided as discussed in Reference 4. The 30-minute Frequency is considered reasonable in view of the instrumentation available in the control room to monitor the status of the RCS. The Surveillance has been modified by a Note which requires the Surveillance to be performed only during heatup and cooldown of the system.

REFERENCES

1. 10 CFR 50.2, "Definitions."
2. 10 CFR 50.55a, "Codes and Standards."
3. WCAP-11618, "MERITS Program-Phase II, Task 5, Criteria Application," including Addendum 1 dated April, 1989, as clarified by Reference 5.
4. Westinghouse letter WAT-D-8376, "Reactor Coolant System Accelerated Cooldown," dated November 5, 1990.
5. TVA letter, "Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM)," dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, "Watts Bar Technical Requirements Manual," (ADAMS Accession No. ML073620391).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Reactor Vessel Head Vent System

BASES

BACKGROUND

The Reactor Vessel Head Vent System (RVHVS) is installed on the reactor vessel head. The RVHVS consists of a safety-grade venting flow path with redundancy around process solenoid valves. Two one inch solenoid-operated globe valves are mounted in series in each redundant portion of the flow path. The piping between these valves is provided with a temperature monitor. Any leakage through the upstream valve will be detected as an increase in temperature. The two redundant upstream valves are open/close isolation valves and are powered by opposite vital power buses. The two redundant downstream valves are throttle valves that are used to regulate the release rate of the non-condensible gases and steam. The two throttle valves are also powered by opposite vital power buses. All four valves are remote, manual-operated from the control room. The valves are normally closed, de-energized and designed to fail closed in accordance with Regulatory Guide 1.48. The system provides venting during plant startup/shutdown or for post-accident. The system is designed to operate in the containment atmosphere during and after a design basis event. However, the system is not utilized during emergency operation until an inadequate water level in the reactor vessel has been determined. During an incident with hydrogen generation and release, a venting period of approximately ten minutes is acceptable without violating the combustible concentration of hydrogen in the containment.

The capability and the function of the system are consistent with the requirements of Item II.B.1 of NUREG-0737, “Clarification of TMI Action Plan Requirements” (Ref. 1). Direct operator action is required to actuate the system. System actuation is only required when the accumulation of non-condensible gases could impair forced or natural circulation and, hence, cooling of the core.

APPLICABLE SAFETY ANALYSES

The RVHVS is designed to ensure that non-condensible gases do not accumulate under the reactor vessel head and thereby impair the cooling of the core. However, in designing the accident sequences for theoretical hazard evaluation, the RVHVS is not assumed to be a system that directly serves to prevent or mitigate a DBA or transient (Refs. 2 & 3).

BASES (continued)

TR

TR 3.4.3 requires that the two redundant vent paths are OPERABLE. One condition for OPERABILITY is that the upstream manual isolation valve is locked open. However, in case of one inoperable path, one condition for continued operation (while restorative actions take place) is that the inoperable path is maintained closed with power removed from both valve actuators. With two paths inoperable, no requirement exists with respect to isolation during the much shorter time of restorative actions.

APPLICABILITY

The TR is basically protecting against uncovering the core and reduces the possibility for impairment of natural or forced circulation through the core. This is mainly a concern during the production of power and early in the decay heat removal phase. Accordingly, Applicability is consistent with operation in MODES 1, 2, 3 and 4. In higher-numbered MODES, the heat flux in the core is low and protection by this TR is not required.

ACTIONS

A.1 and A.2

With one vent path inoperable, it is necessary to immediately start actions to close and fully isolate the inoperable path from the Reactor Coolant System. The inoperable path must be restored to OPERABLE condition in 30 days. It should be noted that during this period of time one path is fully OPERABLE. If the need for venting should occur during this time period, the OPERABLE path will provide 100% of the required venting capacity. Based on this, 30 days is an acceptable time period for restoring the inoperable path.

B.1

With two paths inoperable, it is required to restore one path in 72 hours. The 72 hours is based on operating experience and is a reasonable time period for identifying and correcting problems which could be associated with an inoperable path.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the Required Action and associated Completion Time of Condition A or B is not met, the plant must be placed in a condition in which the TR does not apply. This is accomplished by placing the unit in MODE 3 within 6 hours and MODE 5 in an additional 30 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required conditions from full power conditions in an orderly manner and without challenging plant systems.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.4.3.1, TSR 3.4.3.2 and TSR 3.4.3.3

Every 18 months it is necessary to verify that each of the two vent paths is OPERABLE. This verification consists of checking that the manual isolation valve is locked in the open position. Further, the two open/close isolation valves and the two throttle control valves are operated from the control room, in accordance with the Inservice Testing Program through one complete cycle of full travel. Lastly, the test includes a verification of flow through the two vent paths.

REFERENCES

1. NUREG-0737, “Clarification of TMI Action Plan Requirements.”

2. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 3.

3. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM),” dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 Chemistry

BASES

BACKGROUND

The Reactor Coolant System (RCS) water chemistry is selected to minimize corrosion. A periodic analysis of the coolant chemical composition is performed to verify that the reactor coolant quality meets the specifications (Ref. 1). This Technical Requirement places limits on the dissolved oxygen, chloride and fluoride content of the RCS to minimize corrosion.

Limiting dissolved oxygen content of the RCS limits the amount of general corrosion and reduces the possibility of stress corrosion. General corrosion is a contributing factor in Reactor Coolant Activity (Refs. 2, 3 & 4) and must be controlled for ALARA (as low as reasonably achievable) considerations as well as structural integrity considerations.

Both chlorides and fluorides have been shown to cause stress corrosion if present in the RCS in sufficiently high concentrations at high pressure and temperature conditions. Stress corrosion can lead to either localized leakage or catastrophic failure of the RCS. The associated effects of exceeding the dissolved oxygen, chloride, and fluoride limits are time and temperature dependent. Corrosion studies show that operation may be continued with contaminant concentration levels in excess of the Steady-State Limits, up to the Transient Limits, for the specified limited time intervals without having a significant effect on the structural integrity of the RCS.

APPLICABLE SAFETY ANALYSES

Minimizing corrosion of the RCS reduces the potential for RCS leakage and for failure due to stress corrosion, thus ultimately ensuring the structural integrity of the RCS (Refs. 3 & 4). It is not, however, a consideration in the analyses of Design Basis Accidents.

TR

TR 3.4.4 establishes the limits on concentration of dissolved oxygen, chloride and fluoride in the RCS. These limits ensure that dissolved oxygen, chloride and fluoride concentrations are maintained at levels low enough to prevent unacceptable degradation of the RCS pressure boundary.

BASES (continued)

APPLICABILITY

Concentrations of dissolved oxygen, chloride and fluoride in the RCS must be maintained within limits at all times. Applicability is modified by a Note stating with $T_{avg} \leq 250°F$, the dissolved oxygen limit is not applicable.

ACTIONS

A.1

If one or more chemistry parameters are not within Steady State Limits in MODES 1, 2, 3, and 4, the parameter(s) must be restored to its Steady State Limit within 24 hours. This allows time to take corrective actions to restore the contaminant concentrations to within the Steady State Limits.

B.1 and B.2

With one or more chemistry parameters not within Transient Limits in MODES 1, 2, 3, and 4, or if the Required Action of Condition A is not met in the associated Completion Time, the plant must be placed in a condition where the limit is not applicable or where corrosion rates are reduced. This is accomplished by placing the plant in MODE 3 within 6 hours and MODE 5 within 36 hours. In MODE 5, the dissolved oxygen limit is not applicable and stress corrosion rates are reduced. The 6 hours allotted to reach MODE 3 is a reasonable time, based on operating experience, to shutdown the plant from full power in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows 36 hours for restoration of the parameters and to reach MODE 5.

If high chloride or fluoride concentrations are the reason for entering MODE 5, and the condition is not corrected before entering MODE 5, Required Actions C.1, C.2 and C.3 must be performed.

C.1

If RCS chloride or fluoride concentration are not within Steady State Limits for more than 24 hours in any condition other than MODES 1, 2, 3 or 4, or if RCS chloride or fluoride concentration are not within Transient Limits for any amount of time in any condition other than MODES 1, 2, 3 or 4, action must be immediately initiated to reduce pressurizer pressure to $\leq$ 500 psig unless it is already below 500 psig. The immediate Completion Time is consistent with the required times for actions requiring prompt attention.

A Note is added to Condition C stating that all Required Actions must be completed whenever this Condition is entered.

(continued)

BASES

ACTIONS (continued)

C.2 and C.3

In addition to Required Action C.1, an engineering evaluation must be performed to determine the effects of the out-of-limit condition on the structural integrity of the RCS. It must also be determined that the RCS remains acceptable for continued operation. These actions must be taken prior to increasing pressurizer pressure above 500 psig or prior to entry to MODE 4. These evaluations are necessary because of the time/temperature/concentration dependency of the effects of exceeding the limits. Corrosion evaluations for conditions outside the limits are made on a case by case basis.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.4.4.1, 3.4.4.2 and 3.4.4.3

Demonstrating that the chemistry parameters are within their Steady State Limits at a Frequency of 72 hours provides adequate assurance that concentrations in excess of the limits will be detected in sufficient time to take corrective action. TSR 3.4.4.1 is modified by a Note stating that it is not required with $T_{avg} \leq 250°F$. With $T_{avg} \leq 250°F$, the dissolved oxygen limit is not applicable.

REFERENCES

1. Watts Bar FSAR, Section 5.2, “Integrity of Reactor Coolant Pressure Boundary.”

2. Watts Bar FSAR, Section 11.1, “Source Terms.”

3. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 4.

4. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM),” dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 Piping System Structural Integrity

BASES

BACKGROUND

Inservice inspection and pressure testing of ASME Code Class 1, 2, and 3 components in all systems are performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code (Ref. 1) and applicable Addenda, as required by 10 CFR 50.55a(g) (Ref. 2). Exception to these requirements apply where relief has been granted by the Commission pursuant to 10 CFR 50.55a(g)(6)(i) and (a)(3). In general, the surveillance intervals specified in Section XI of the ASME Code apply. However, the Inservice Inspection Program includes a clarification of the frequencies for performing the inservice inspection and testing activities required by Section XI of the ASME Code. This clarification is provided to ensure consistency in surveillance intervals throughout the Technical Specifications. Each reactor coolant pump flywheel is, in addition, inspected as recommended in Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1, August 1975 (Ref. 3).

APPLICABLE SAFETY ANALYSES

Certain components which are designed and manufactured to the requirements of specific sections of the ASME Boiler and Pressure Vessel Code are part of the primary success path and function to mitigate DBAs and transients. However, the operability of these components is addressed in the relevant specifications that cover individual components. In addition, this particular Requirement covers only structural integrity inspection/testing requirements for these components, which is not a consideration in designing the accident sequences for theoretical hazard evaluation (Refs. 4 & 5).

BASES (continued)

TR

TR 3.4.5 requires that the structural integrity of the ASME Code Class 1, 2, and 3 components in all systems be maintained in accordance with TSR 3.4.5.1 and TSR 3.4.5.2. In those areas where conflict may exist between the Technical Specifications and the ASME Boiler and Pressure Vessel Code, the Technical Specifications take precedence.

APPLICABILITY

The structural integrity of the ASME Code Class 1 components is required in all MODES, when the temperature is above the minimum temperature required by NDT considerations. For ASME Code Class 2 components, the structural integrity is required when the temperature is above 200°F. For ASME Code Class 3 components, the structural integrity is required at all times when the particular component is in service.

ACTIONS

A.1 and A.2

Required Actions A.1 and A.2 apply to ASME Code Class 1 components. Required Action A.1 stipulates that structural integrity should be restored before the temperature of the component is increased more than 50°F above the minimum temperature required by NDT considerations. Alternatively, the component could be isolated before the temperature reaches 50°F above the minimum temperature required by NDT considerations.

B.1 and B.2

Required Actions B.1 and B.2 apply to ASME Code Class 2 components. Required Action B.1 stipulates that structural integrity should be restored before the temperature of the component is increased more than 200°F. Alternatively, the component could be isolated before the temperature reaches 200°F.

C.1, C.2.1, and C.2.2

Required Actions C.1, C.2.1, and C.2.2 apply to ASME Code Class 3 components. Required Action C.1 requires that the applicable Conditions and Required Actions for the affected components be entered immediately. Additionally, the structural integrity of all components must be satisfied or the particular component which does not satisfy the required structural integrity must be isolated from the system within the Completion Time specified in the affected components LCO or TR.

BASES (continued)

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.4.5.1

This surveillance stipulates inspection of the coolant pump flywheel in accordance with Regulatory Position C.4.b of Regulatory Guide 1.14, Revision 1. This inspection verifies the structural integrity of the flywheel.

TSR 3.4.5.2

TSR 3.4.5.2 requires the verification of structural integrity of ASME Code Class 1, 2, and 3 components are in accordance with the Inservice Inspection Program.

REFERENCES

1. ASME Boiler and Pressure Vessel Code, “Section XI: Rules for Inservice Inspection of Nuclear Power Plant Components.”

2. 10 CFR 50.55a, “Codes and Standards.”

3. Regulatory Guide 1.14, “Reactor Coolant Pump Flywheel Integrity,” Revision 1, 1975.

4. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 5.

5. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM),” dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Ice Bed Temperature Monitoring System

BASES

BACKGROUND

The Ice Bed Temperature Monitoring System consists of Resistance Temperature Detectors (RTDs) which are located in various parts of the ice condenser. They serve to verify the attainment of a uniform equilibrium temperature in the ice bed and to detect general gradual temperature rise in the cooling system if breakdown occurs.

Forty-seven RTDs are mounted on ice bed probes which are located throughout the ice bed (i.e., ice bed and floor/air). These 47 RTDs and an additional 38 RTDs which serve to monitor various ice condenser temperatures (i.e., floor cooling piping, wall panels, and wear slab) tie into 2 separate temperature recorders (indicator), located in the Incore Instrumentation Room. The recorders multiplex the ice condenser RTD signals via an Ethernet connection to the Integrated Computer System (ICS) for Main Control Room indication on the Satellite Display System (SDS). There is one alarm common to the group of 47 RTDs indicating the ice bed temperature is abnormal which is caused by either a high-high, high, or low temperature. There are also six temperature switches located at various points in the ice bed that provide an alarm in the MCR should the ice bed temperature exceed preset value (Ref. 1). In addition, the 47 RTDs can be read from the local ice condenser temperature recorder (indicator) located in the Incore Instrumentation Room.

APPLICABLE SAFETY ANALYSES

The ice condenser is a passive device requiring only maintenance of the ice inventory in the ice bed. As such there are no actuation circuits or equipment which is required for the ice condenser to operate in the event of a Loss of Coolant Accident (LOCA). The Ice Bed Temperature Monitoring System serves only to monitor the ice bed temperature. Since the ice bed has a very large thermal capacity, postulated off-normal conditions can be successfully tolerated for a week to two weeks. Therefore, the Ice Bed Temperature Monitoring System provides an early warning of any incipient ice condenser temperature anomalies. The Ice Bed Temperature Monitoring System is not assumed to be OPERABLE to mitigate the consequences of a DBA or transient. Based on the PRA Summary Report (Ref. 2), the Ice Bed Temperature Monitoring System has not been identified as a significant risk contributor.

BASES (continued)

TR

TR 3.6.1 states that the Ice Bed Temperature Monitoring System shall be OPERABLE with at least two OPERABLE RTD channels in the ice bed at each of three basic elevations: 10' 6", 30' 9", and 55' above the floor of the ice condenser, for each one-third of the ice condenser.

The OPERABILITY of the Ice Bed Temperature Monitoring System ensures that the capability is available for monitoring the ice bed temperature. The ice bed temperature may be determined at the ice condenser temperature recorder (indicator) located in the Incore Instrumentation Room as well as in the Main Control Room (i.e., Satellite Display System (SDS)) and the Monitoring System would still be considered OPERABLE. In the event the Monitoring System is inoperable, the Required Actions provide assurance that the ice bed heat removal capacity will be retained within the specified time limits.

APPLICABILITY

The Ice Bed Temperature Monitoring System is required to be OPERABLE in MODES 1, 2, 3, and 4. This corresponds to the Applicability requirements for the ice bed in Technical Specification LCO 3.6.11, “Ice Bed.”

ACTIONS

A.1

With the ice bed temperature not available in the Main Control Room (i.e., Satellite Display System (SDS)), the ice bed temperature must be determined at the temperature recorder (indicator) located in the Incore Instrumentation Room every 12 hours. Since the ice bed has a very large thermal capacity, postulated off-normal conditions can be successfully tolerated for one or two weeks. Therefore, a 12 hour surveillance of the ice bed temperature will give sufficient warning of any incipient ice condenser temperature anomalies.

B.1.1, B.1.2, and B.1.3

With the Ice Bed Temperature Monitoring System inoperable and being unable to determine the ice bed temperature at the temperature recorder (indicator), Required Actions B.1.1, B.1.2, and B.1.3 require verification that: the ice compartment lower inlet doors, intermediate deck doors, and top deck doors are closed; the last recorded mean ice bed temperature was less than or equal to 20°F (value does not account for instrument error) and steady; and the Ice Condenser Cooling System is OPERABLE.

(continued)

BASES

ACTIONS

B.1.1, B.1.2, and B.1.3 (continued)

The Completion Time of 1 hour and every 12 hours thereafter to perform Required Actions B.1.1 and B.1.3 and 1 hour to perform Required Action B.1.2 is reasonable and based upon the typical time necessary to perform the Required Actions. These Required Actions, along with the high thermal capacity of the ice bed, ensure that the ice bed will remain below critical temperatures while the Monitoring System is inoperable.

B.2.1 and B.2.2

With the Ice Bed Temperature Monitoring System inoperable and being unable to determine the ice bed temperature at the temperature recorder (indicator), either the Monitoring System or the temperature recorder (indicator) must be restored to OPERABLE status within 30 days. A Completion Time of 30 days is given, provided that Required Actions B.1.1, B.1.2, and B.1.3 are met. These Required Actions, along with the high thermal capacity of the ice bed, ensure that the ice bed will remain below critical temperatures during the 30 day Completion Time. Also, the six alarmed temperature switches (which provide an alarm at 25°F) will continue to monitor the ice bed temperature. If the Ice Condenser Cooling System becomes inoperable before the Ice Bed Temperature Monitoring System is OPERABLE, then Required Action C must be performed.

C.1.1 and C.1.2

With the Ice Bed Temperature Monitoring System inoperable and being unable to determine the ice bed temperature at the temperature recorder (indicator) and with the Ice Condenser Cooling System not satisfying the minimum components OPERABILITY requirements of Required Action B.1.3, Required Actions C.1.1 and C.1.2 require verification that: the ice compartment lower inlet doors, intermediate deck doors, and top deck doors are closed; and that the last recorded mean ice bed temperature was less than or equal to 15°F (value does not account for instrument error) and steady. The Completion Time of 1 hour and every 12 hours thereafter to perform Required Action C.1.1 and 1 hour to perform Required Action C.1.2 is reasonable and based upon the typical time necessary to perform the Required Actions. These Required Actions, along with the high thermal capacity of the ice bed, ensure that the ice bed will remain below critical temperatures while the Ice Bed Temperature Monitoring System, temperature recorder (indicator), and Ice Condenser Cooling System are inoperable.

(continued)

BASES

ACTIONS (continued)

C.2.1, C.2.2, and C.2.3

With the Ice Bed Temperature Monitoring System inoperable and being unable to determine the ice bed temperature at the temperature recorder (indicator) and with the Ice Condenser Cooling System not satisfying the minimum components OPERABILITY requirements of Required Action B.1.3, the Ice Condenser Cooling System, Ice Bed Temperature Monitoring System or the temperature recorder (indicator) must be restored to OPERABLE status. A Completion Time of 6 days is given, provided that Required Actions C.1.1 and C.1.2 are met. These Required Actions, along with the high thermal capacity of the ice bed, ensure that the ice bed will remain below critical temperatures during the 6 day Completion Time. Also, the six alarmed temperature switches (which provide an alarm at 25°F) will continue to monitor the ice bed temperature.

D.1 and D.2

If the Required Action and associated Completion Time of Condition A, B or C is not met, the integrity of the ice bed may be threatened. Therefore, the plant must be placed in a MODE in which the TR does not apply. This is done by placing the plant in MODE 3 in 6 hours and MODE 5 in 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.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.6.1.1

Performance of a CHANNEL CHECK on the Ice Bed Temperature Monitoring System once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or of even something more serious. The Surveillance Frequency, about once every shift, is based on operating experience that demonstrates the rarity of channel failure. Thus, TSR 3.6.1.1 ensures that loss of function will be identified within 12 hours.

BASES (continued)

REFERENCES

1. Watts Bar FSAR, Section 6.7.15, “Ice Condenser Instrumentation.”

2. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 3.

3. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM),” dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Inlet Door Position Monitoring System

BASES

BACKGROUND

Ninety-six limit switches monitor the position of the lower inlet doors. Two switches are mounted on the door frame for each door panel. The position and movement of the switches are such that the doors must be effectively sealed before the switches are actuated. A single annunciator window in the control room gives a common alarm signal when any door is open. Open/shut indication is also provided at the lower inlet door position display panel located in the Main Control Room. For door monitoring purposes, the ice condenser is divided into six zones, each containing four inlet door assemblies, or a total of eight door panels. The limit switches on the doors in any single zone are wired to a single light on the inlet door position display panel such that a closed light indicates that all the doors in that zone are shut and an open light indicates that one or more doors in that zone are open (Ref. 1). The display panel is considered the Inlet Door Position Monitoring System.

Monitoring of inlet door position is necessary because the inlet doors form the barrier to air flow through the inlet ports of the ice condenser for normal unit operation. Failure of the Inlet Door Position Monitoring System requires an alternate OPERABLE monitoring system to be used to ensure that the ice condenser is not degraded.

APPLICABLE SAFETY ANALYSES

Proper operation of the inlet doors is necessary to mitigate the consequences of a loss of coolant accident or a main steam line break inside containment. The Inlet Door Position Monitoring System, however, is not required for proper operation of the inlet doors, nor is it considered OPERABLE as an initial condition for a DBA. Hence, the Inlet Door Position Monitoring System is not a consideration in the analyses of DBAs. Based on the PRA Summary Report in References 2 and 3, the Inlet Door Position Monitoring System has not been identified as a significant risk contributor.

BASES (continued)

TR

The Inlet Door Position Monitoring System provides the only direct means of determining that the inlet doors are shut. Since an open door would allow heat input that could cause sublimation and mass transfer of ice in the ice condenser compartment, the Inlet Door Position Monitoring System must be OPERABLE whenever the ice bed is required to be OPERABLE. This ensures early detection of an inadvertently opened or failed door, allowing prompt action before ice bed degradation can occur.

APPLICABILITY

The Inlet Door Position Monitoring System is required to be OPERABLE in MODES 1, 2, 3 and 4. This corresponds to the Applicability requirements for the ice bed.

ACTIONS

A.1 and A.2

If the Inlet Door Position Monitoring System is inoperable due to the inability to complete a channel check, an alternate OPERABLE monitoring system must be used to ensure that the ice condenser is not degraded. This is done by confirming the Ice Bed Temperature Monitoring System is OPERABLE with the ice bed temperature ≤ 27°F (value does not account for instrument error). This Action must be completed within 4 hours and each 4 hours thereafter. The Frequency of 4 hours is based on the fact that temperature changes cannot occur rapidly in the ice bed because of the large mass of ice involved. Since this is an indirect means of monitoring inlet door position, operation in MODE 1 may continue indefinitely if through analysis it can be demonstrated that the ice condenser doors are shut. The analysis must be completed within 14 days of entering the Action. If the ice bed temperature increases to above 27°F, or an analysis demonstrating the ice condenser doors are shut cannot be completed, the ice bed must be declared inoperable in accordance with Technical Specification 3.6.11, “Ice Bed.”

B.1

If the Inlet Positon Monitoring System is inoperable for reasons other than the inability to complete a channel check, the Inlet Door Position Monitoring System must be restored to OPERABLE status within 48 hours. The 48 hour Completion Time is based on the fact that, with the very large mass of ice involved, it would not be possible for the temperature to increase to the melting point and a significant amount of ice to melt in a 48 hour period.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the Required Action and associated Completion Time of Condition B cannot be met, the plant must be placed in a condition where OPERABILITY of the Inlet Door Position Monitoring System is not required. This is accomplished by placing the plant in MODE 4 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required MODES from full power in an orderly manner and without challenging plant systems.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.6.2.1

Performance of the CHANNEL CHECK for the Inlet Door Position Monitoring System once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is 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 two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. Performance of the CHANNEL CHECK helps to ensure that the instrumentation continues to operate properly between each TADOT. The dual switch arrangement on each door allows comparison of open and shut indicators for each zone as well as a check with the annunciator window. When equipment conditions exist that prevent the preferred direct comparison of open and shut indicators for each zone as described above, indirect methods may be employed to verify that the inlet doors are shut. The indirect methods include the performance of a continuity check of the circuit used by the annunciator window, by monitoring ice bed temperature, or by monitoring ice condenser and containment parameters. The annunciator continuity check can confirm if one or more inlet door zone switch contacts are closed which would represent an open inlet door. The Ice Bed Temperature Monitoring System can be used to provide confirmation of inlet door closure by confirming there is uniform equilibrium temperature in the ice bed. Ice condenser and containment parameters such as temperature and humidity can also be used to determine if an ice condenser inlet door is open.

When indirect methods are used to verify ice condenser inlet doors are shut, a technical analysis must be completed and documented in accordance with the corrective action program. In those instances when a technical analysis cannot be made within the allowed Completion Time,

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.6.2.1 (continued)

the Inlet Door Position Monitoring System must be declared inoperable and Technical Specification LCO 3.6.12 Condition D must be entered immediately.

TSR 3.6.2.2

TSR 3.6.2.2 is the performance of a TADOT every 18 months. It checks trip devices (limit switches) that provide actuation signals directly. The 18 month Frequency was developed considering the plant conditions needed to perform TSR 3.6.2.2. The 18 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment.

TSR 3.6.2.3

TSR 3.6.2.3 requires verification that the monitoring system correctly indicates the status of each inlet door as the door is opened and reclosed during its Technical Specification testing. This provides ongoing operational testing of the indicating system. The Frequency coincides with the Technical Specifications testing performed.

REFERENCES

1. Watts Bar FSAR, Section 6.7, “Ice Condenser System.”

2. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 3.

3. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM),” dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Lower Compartment Cooling (LCC) System

BASES

BACKGROUND

The Lower Compartment Cooling (LCC) fans provide non-safety related cooling for the lower compartment spaces after all accidents, except those that initiate a Phase B Containment Isolation Signal (Ref. 1), when the non-safety related cooling coils and cooling water supply are available. LCC fans perform a safety related air recirculation function in the lower containment pocketed (dead ended) spaces after a main steam line break (MSLB) to prevent the formation of localized hot spots which could exceed the qualification temperatures of equipment required to operate post accident. The LCC fans are not required to operate during or after a loss of coolant accident (LOCA).

After an MSLB, one LCC train will be manually started a minimum of 1 1/2 hours, but less than 4 hours, after the accident to ensure that the dead ended compartment temperatures are kept below the environmental qualification limit. Each train consists of two 50% capacity fans, backdraft damper, instrumentation and controls, and associated ductwork. Each train is powered from separate class 1E power sources.

APPLICABLE SAFETY ANALYSES

The LCC fans recirculate air in the lower compartment spaces after an MSLB. Under these circumstances, the intact Reactor Coolant System piping will serve as a long term heat source. After the ice is melted, the heat from the Reactor Coolant System (RCS) will result in a gradual temperature increase in the sub-compartments of the lower containment. The LCC System may be used to provide long term containment cooling after a MSLB to assure electrical equipment qualification requirements are maintained. .

BASES (continued)

TR

The TR specifies the equipment which needs to be OPERABLE in order to ensure that air can be circulated in the sub-compartments if an accident should take place. At least one LCC train must be placed in operation after the accident. The LCC fans do not perform a cooling function, which means that the coils and the secondary cooling water circuits need not be OPERABLE. However, secondary side failures which could impair the operation of the fans and the circulation of the air must be prevented.

APPLICABILITY

The flow of air to the sub-compartments is necessary following an MSLB where the RCS represents a major heat source in lower containment. Based on the temperature of the RCS, this could be in MODES 1 through 4. In MODES 5 and 6, the probability for an accident is small and, in any case, the heat capacity of the RCS is limited and, therefore, not able to heat up the lower compartment spaces to such an extent that equipment could degrade. The specification is therefore only applicable in MODES 1, 2, 3 and 4.

ACTIONS

A.1

With one fan inoperable, the inoperable fan must be restored to OPERABLE status within 7 days. During this period, the remaining three fans are available to circulate the air in the lower compartments of the containment. However, only two fans are necessary to prevent the hot spots. Hence, there is one spare fan available. The 7 day Completion Time is based on the low probability of an event requiring emergency fan operation, the availability of one fan more than required, and the availability of alternate cooling means.

B.1

With two fans inoperable the plant has still adequate fan capacity to circulate air if an accident should take place. However, in this case no spare capacity is available. Hence, it is required to restore at least one fan to OPERABLE status within 72 hours. With one fan restored, three fans will be OPERABLE and Condition A must be entered. This will allow another 7 days to restore the last inoperable fan to OPERABLE status. The 72 hour Completion Time in Condition B is based on the low probability of an event requiring fan operation simultaneous with further fan deterioration, and the availability of alternate cooling means.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

If the Required Actions of A.1 and B.1 cannot be completed within the required Completion Time or if more than two fans are inoperable, the plant must be placed in a MODE in which the TR does not apply. This is done by placing the plant in at least MODE 3 within 6 hours and in MODE 5 within an additional 30 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.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.6.3.1

During normal operation, three of the four LCCs operate to remove heat from the lower compartments of the containment. This means that three of the four fans are operating at all times. Hence, this gives certainty that at least three fans are OPERABLE. The test is for the fan that has not been in operation during the preceding 31 days and to verify that all fans can be manually started from the control room. The 15 minutes running test is optional for fans that have been running the previous 31 days, or will be running after the Surveillance has been carried out.

REFERENCES

1. Watts Bar FSAR, Section 6.2.2, “Containment Heat Removal Systems.”

2. Thomas E. Murley (NRC) letter to W. S. Wilgus, dated May 9, 1988, forwarding the NRC Staff review of the “Nuclear Steam Supply System Vendor Owners Groups' Application of the Commission's Interim Policy Statement Criteria to the Standard Technical Specifications.”

B 3.7 PLANT SYSTEMS

B 3.7.1 Steam Generator Pressure / Temperature Limitations

BASES

BACKGROUND

In order to meet regulatory and code requirements with respect to material toughness, certain limits on steam generator pressure and temperature are established. Material toughness varies with temperature and is lower at room temperature than at operating temperature. One indicator of the temperature effect on ductility is the nil-ductility temperature (NDT). Therefore, a nil-ductility reference temperature (RT_{NDT}) has been determined by experimental means. The RT_{NDT} is that temperature below which brittle (non-ductile) fracture may occur. For the steam generators, the RT_{NDT} has been determined to be 10°F (Ref. 1). Considering uncertainties and proper margins, the minimum operating temperature has been determined to be 70°F. The 70°F temperature must be established before the pressure is increased to 200 psig. This limitation on steam generator pressure and temperature ensures that the pressure-induced stresses in the steam generators do not exceed the maximum allowable fracture toughness stress limits.

The fracture mechanic methodology, which is used to determine the stresses and material toughness, follows the guidance given by 10 CFR 50, Appendix G (Ref. 2). Reference 1 mandates the use of ASME Boiler and Pressure Vessel Code, Section III, Appendix G (Ref. 4).

APPLICABLE SAFETY ANALYSES

The RT_{NDT} limit is not derived from the Design Basis Accident analyses. The RT_{NDT} limit is imposed during normal operation to avert encountering pressure/temperature combinations which are not analyzed as part of the steam generator design. Unanalyzed pressure/temperature combinations could cause propagation of minor, undetected flaws, which could cause brittle failure of the pressure boundary. Because the RT_{NDT} limit is related to normal operation, the RT_{NDT} limit is not a consideration in designing the accident sequences for theoretical hazard evaluations (Ref. 5 & 6).

BASES (continued)

TR

TR 3.7.1 requires that the pressures on the primary and the secondary sides in the steam generator are kept at or below 200 psig when the temperature is less than or equal to 70°F. The pressure induced stress from the 200 psig pressure is low enough to be insignificant, even at temperatures at or below RT_{NDT}.

APPLICABILITY

The operating requirements which must be observed to avoid a condition, which could lead to brittle failure, are not strictly limited to specific MODES. Hence, in general, Applicability should be At All Times. However, in practice it is unlikely that these limits will be violated in the lower numbered MODES, due to the high operating temperature on the primary as well as the secondary side in the steam generators. Accordingly, the limits are most easily violated at low temperature, during shutdown and startup of the plant. Applicability can therefore conveniently be limited to whenever the temperature on the primary or the secondary side is at or below 70°F. Since cooldown would make the steam generator more susceptible to brittle failure, a Note to the Applicability has been added to preclude cooldown in the primary or secondary to ≤ 70°F when the pressure is > 200 psig.

ACTIONS

A.1, A.2 and A.3

With the combination of pressure and temperature not within limits, a reduction in pressure to ≤ 200 psig is required within 30 minutes. An engineering evaluation must be performed to determine the effect on the structural integrity of the pressure boundary. The evaluation must be finished and the conclusion made that no hazard exists before the temperature is increased to more than 200°F. Condition A is modified by a Note which states that whenever Condition A is entered, all ACTIONS A.1through A.3 must be completed.

BASES (continued)

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.7.1.1

TSR 3.7.1.1 verifies that the pressures on the primary and the secondary sides in the steam generators are less than 200 psig (value does not account for instrument error). At temperatures below 70°F (value does not account for instrument error), the temperature margin to RT_{NDT} is diminished. Hence, the pressure must be checked every hour to ensure that the material toughness criteria are not violated. The 1 hour Frequency is based on engineering judgment and is consistent with industry practice.

Note: Instrument uncertainty has been considered in establishing these values and is discussed in this Bases section under Background.

REFERENCES

1. WCAP-13146, “Technical Basis for Determination of Secondary Side Pressure Test Temperatures in Sequoyah and Watts Bar Units 1 and 2 Steam Generators.”

2. 10 CFR 50, Appendix G, “Fracture Toughness Requirements.”

3. Not used.

4. ASME Boiler and Pressure Code, Section III.

5. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as modified by Reference 6.

6. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM), dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.7 PLANT SYSTEMS

B 3.7.2 Flood Protection Plan

BASES

BACKGROUND

Nuclear power plants are designed to prevent the loss of capability for cold shutdown and maintenance thereof resulting from the most severe flood conditions that can reasonably be predicted to occur at the site as a result of severe hydrometeorological conditions, seismic activity, or both (Ref. 1). Assurance that safety-related facilities are capable of surviving all possible flood conditions is provided by the flood protection plan.

The elevations of plant features which could be affected by the submergence during floods vary from 739.2 ft Mean Sea Level (MSL) (excluding wave runup) to 741.7 ft MSL (including wave runup). Plant grade is elevation 728.0 ft MSL which can be exceeded by extreme rainfall floods and closely approached by seismic-caused dam failure floods. A warning plan is needed to assure plant safety from floods.

The warning plan is divided into two stages. This two-stage plan is designed to allow adequate time for preparing the plant for operation in the flood mode and to avoid excessive economic loss in case a potential flood does not fully develop. Stage I warning, which is a minimum of 10 hours, allows preparation steps, causing some damage to be sustained, but will postpone major economic damage. Stage II warning, which is a minimum of 17 hours, is a warning that a forthcoming flood above grade is predicted.

Stage I procedures consist of a controlled reactor shutdown and other easily revokable steps, such as moving flood supplies above the probable maximum flood elevation and making temporary connections and load adjustments on the onsite power supply. After unit shutdown, the Reactor Coolant System will be cooled and the pressure will be reduced to less than 350 psig. Stage II procedures are the least easily revokable and more damaging steps necessary to have the plant in the flood mode when the flood exceeds plant grade. Heat removal from the steam generators will be accomplished by adding river water from the Fire Protection System, and relieving steam to the atmosphere through the steam generator power operated relief valves. Other essential plant cooling loads will be transferred from the Component Cooling Water System to the Essential Raw Cooling Water System (ERCW); the ERCW will also replace the Raw Cooling Water System to the ice condensers. The Radioactive Waste System will be secured by filling tanks below Design Bases Flood (DBF) level with enough water to prevent floatation;

(continued)

BASES

BACKGROUND (continued)	one exception is the waste gas decay tanks, which are sealed and anchored against floatation. Power and communication lines running beneath the DBF that are not required for submersed operation will be disconnected, and batteries below the DBF will be disconnected (Ref. 2).
APPLICABLE SAFETY ANALYSES	The flood protection plan specifies flood control measures to protect safety related equipment in the event that the maximum elevation for the ultimate heat sink or other body of water, as applicable, is exceeded. Because external flooding conditions present substantial warning time to achieve plant shutdown, this requirement is not a contributor to a dominant risk sequence (Ref. 3 & 4).
TR	TR 3.7.2 requires that the flood protection plan be ready for implementation to maintain the plant in a safe condition. This requirement ensures that facility protective actions will be taken and operation will be terminated in the event of flood conditions.
APPLICABILITY	The flood protection plan TR is applicable when one or more of the following conditions exist: a. Extreme flood producing rainfall conditions in the east Tennessee watershed, or b. Receipt of notification from TVA River Operations (RO) that predicted flood levels based on rainfall on the ground or potential failure problems with one or more dams combined with critical headwater elevations and flood-producing rainfall may result in subsequent issuance of a Stage I flood warning.

BASES (continued)

ACTIONS

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

If a Stage I flood warning is issued, several actions are required to be taken. The first requires the plant to be placed in MODE 3 in 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

Upon issuance of a Stage I flood warning, initiate and complete the Stage I flood protection plan, which involves preparatory steps. The required Completion Time for this Required Action is 10 hours. The plant is also required to be brought from full power operation to a safe shutdown. This is accomplished by Required Action A.3. This Required Action requires the establishment of a SHUTDOWN MARGIN of at least 5% $\Delta k/k$ and T_{avg} less than or equal to 350°F. The Completion Time of 10 hours is reasonable to accomplish the required SHUTDOWN MARGIN and T_{avg}.

A.4.1 and A.4.2

Once a Stage I flood warning has been issued, it is necessary to maintain communications between the TVA RO Group and the Watts Bar Nuclear Plant. This is necessary because the TVA RO Group provides the flood forecasting for the Watts Bar Nuclear Plant. The Completion Time of 10 hours corresponds to the time specified to initiate and complete the Stage I flood protection plan.

If communications between the TVA RO Group and the Watts Bar Nuclear Plant have not been established within the required Completion Time, the Stage II flood protection procedure must be initiated and completed within 27 hours. The Completion Time of 27 hours corresponds to the minimum pre-flood preparation time. This is to ensure adequate warning time for safe plant shutdown.

B.1

If the Stage II flood warning has been issued, the Stage II flood protection plan must be initiated and completed within 17 hours or prior to flooding of the site. The Completion Time of 17 hours corresponds to the remaining hours of the 27 hour pre-flood preparation time after the Stage I flood warning consisting of 10 hours has expired, and is an adequate time period to complete Stage II preparations.

At any time it is determined that the potential for flooding at the site does not exist, the Stage I and Stage II flood protection plans are to be terminated immediately.

BASES (continued)

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.7.2.1

This surveillance requires communications between Watts Bar Nuclear Plant and TVA RO Group be established and maintained every 3 hours. A Note for this surveillance states that this is required only when one of the applicability criteria is met. This communications requirement exists because the TVA RO Group provides the flood forecasting for Watts Bar Nuclear Plant. The 3 hour Frequency is adequate for early flood forecasting.

REFERENCES

1. Regulatory Guide 1.59, “Design Basis Floods for Nuclear Power Plants.”

2. Watts Bar FSAR, Section 2.4.14, “Flooding Protection Requirements.”

3. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as modified by Reference 4.

4. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM), dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.7 PLANT SYSTEMS

B 3.7.3 Snubbers

BASES

BACKGROUND

Component standard supports, are those metal supports which are designed to transmit loads from the pressure-retaining boundary of the component to the building structure. Although classified as component standard supports, snubbers require special consideration due to their unique function. Snubbers are either operated hydraulically or mechanically, depending on the nature of the support needed. They are designed to provide no transmission of force during normal plant operations, but function as a rigid support when subjected to dynamic transient loadings. Therefore, snubbers are chosen in lieu of rigid supports where restricting thermal grow during normal operation would induce excessive stresses in the piping nozzles or other equipment. The location and size of the snubbers are determined by stress analysis. Depending on the design classification of the particular piping, different combinations of load conditions are established. These conditions combine loading during normal operation, seismic loading and loading due to plant accidents/transients to four different loading sets. These loading sets are designated: normal, upset, emergency, and faulted condition. The actual loading included in each of the four conditions, depends on the design classification of the piping. The calculated stresses in the piping and other equipment, for each of the four conditions, must be in conformance with established design limits.

Supports for pressure-retaining components are designed in accordance with the rules of the ASME Boiler and Pressure Vessel Code, Section III, Division 1 (Ref. 1). The combination of loadings for each support, including the appropriate stress levels, meet the criteria of Regulatory Guide 1.124, “Design Limits and Loading Combinations for Class 1 Linear-Type Component Supports” (Ref. 2), and Regulatory Guide 1.130, “Design Limits and Loading Combinations for Class 1 Plate-and-Shell-Type Component Supports” (Ref. 3).

APPLICABLE SAFETY ANALYSES

Pipe and equipment supports, in general, are not directly considered in designing the accident sequences for theoretical hazard evaluations. Further, various Probabilistic Risk Assessment (PRA) studies have indicated that snubbers are not of prime importance in a risk significant sequence (Ref. 4 and 5). Therefore, the function of the snubbers is not essential in mitigating the consequences of a DBA or transient (Ref. 6).

BASES (continued)

TR

TR 3.7.3 requires that all snubbers shall be OPERABLE. Individual snubbers may be removed from service for functional testing within the limits established herein without violating these requirements, although Required Actions and Completion Times still apply.

APPLICABILITY

The OPERABILITY of the snubbers is required in MODES 1, 2, 3, and 4. For MODES 5 and 6, the OPERABILITY is limited to the snubbers located on those systems which need to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

If one or more required snubbers are removed from service, the supported system must be declared inoperable immediately and the appropriate LCO entered for that system.

B.1 and B.2

If one or more required snubbers are discovered inoperable, then the supported system must be declared inoperable immediately and the appropriate LCO entered for that system.

Discovery of any snubber as inoperable requires the performance of an engineering evaluation per Table 3.7.3-5 during the 72 hours to:

a) Determine the cause of the failure

As a result of this evaluation, the need for testing other snubbers will be considered. The results from the testing will be used to consider expanded functional testing and cause examination with consideration of manufacturing and design deficiency. It should be noted that the testing must be independent and not combined with TSR 3.7.3.3.

b) Determine the impact on the supported component

This evaluation shall determine if the inoperable snubber has adversely affected the attached component.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

The 72 hours is based on engineering experience and is reasonable, considering the time it will take to identify the problem and take the proper corrective actions. This requirement is considered met for those snubbers rendered inoperable by removal for functional testing by the generic engineering evaluation included in Reference 9.

Another alternative is to perform an engineering evaluation to demonstrate inoperable snubber(s) do not impact the OPERABILITY of the supported system for the existing plant condition (Reference 10).

C.1

If Required Actions under Condition A or Condition B are not met within the required Completion Time, a Condition Report shall be written to document the occurrence.

BASES (continued)

TECHNICAL SURVEILLANCE REQUIREMENTS

The TSRs are preceded by three Notes. Note 1 states that the snubber inservice inspection program shall be carried out in accordance with the requirements in Tables 3.7.3-1, 3.7.3-2 and 3.7.3-3. This represents an enhanced snubber inservice inspection program compared to the Inservice Inspection Program which stipulates inservice inspection in accordance with ASME Section XI. The snubber inservice inspection program includes the requirements of Generic Letter 90-09, "Alternative Requirements for Snubber Visual Inspection Intervals and Corrective Actions." ASME Section XI, 1989 Edition, Subsections IWF-5300(a) and (b) require that inservice examinations of snubbers, using the VT-3 visual examination method described in IWA-2213, and inservice tests of snubbers be performed in accordance with the first Addenda to ASME/ANSI OM-1987, Part 4. Note 2 requires repair or replacement of snubbers which fail inspection, and testing of repaired snubbers before installation. Note 3 indicates that a "snubber type," as used in this TR, is determined by the design and manufacturer, but not by size.

TSR 3.7.3.1

TSR 3.7.3.1 comprises a visual inspection of the snubbers. A pre-fuel load visual inspection and functional test has been performed on each snubber using the acceptance criteria listed in this TSR. The baseline considers that the snubbers have experienced thermal cycling and normal operating service as a result of previous hot functional testing. The initial inservice inspection must be performed on the snubbers prior to completion of the first refueling outage. The frequency of subsequent surveillances depends on the number of snubbers found inoperable from each previous inspection as provided in Table 3.7.3-2 and the Inservice Inspection Program. The acceptance criteria and the remedial ACTIONS are listed in Table 3.7.3-1.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.7.3.1 (continued)

The visual inspections are designed to detect obvious indications of inoperability of the snubbers. Removal of insulation or direct contact with the snubbers is not required initially. However, suspected causes of inoperability are to be investigated and all snubbers of the same type and all snubbers subjected to the same failure mode are to be inspected more frequently.

Until proven otherwise by functional testing, mechanical and hydraulic snubbers are considered OPERABLE, unless they are disconnected at either end, experienced gross deformation of the snubber or structural support, or the hydraulic fluid level is empty for hydraulic snubbers.

The visual inspection frequency is based upon the number of unacceptable snubbers found during the previous inspection. Therefore, the required inspection intervals vary inversely with the number of inoperable snubbers found during an inspection. If a snubber fails the visual acceptance criteria, the snubber is declared unacceptable and cannot be declared OPERABLE via functional testing. However, if the cause of rejection is understood and remedied for that type of snubber and for any other type of snubbers, that may be generically susceptible, and OPERABILITY verified by testing, that snubber may be reclassified acceptable for the purpose of establishing the next surveillance interval.

Snubbers may be categorized, according to accessibility, as noted in the Note to Table 3.7.3-2. The accessibility of each snubber is determined based on radiation level as well as other factors such as temperature, atmosphere, location, etc. The recommendations of Regulatory Guide 8.8, “Information Relevant to Maintaining Occupational Radiation Exposure as Low as Practicable,” (Ref. 7) and Regulatory Guide 8.10, “Operation Philosophy for Maintaining Occupational Radiation Exposure as Low as Practicable,” (Ref. 8), are considered in planning and implementing the visual inspection program.

TSR 3.7.3.2

TSR 3.7.3.2 comprises the inspection of all snubbers attached to systems that have experienced unexpected, potentially damaging transients. The potential impact of the transients is assessed by reviewing operating data and by visually inspecting the associated systems. The review and the inspection must be performed within six months of the event. In addition to the inspection, the freedom-of-motion of the mechanical snubber(s) is verified in accordance with Table 3.7.3-3.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.3.3

TSR 3.7.3.3 comprises the functional testing of hydraulic and mechanical snubbers. The testing for these snubbers have been separated into two sample plans. Sample Plan A (10%) is used for the steam generator hydraulic snubbers based on the small population. Sample Plan B (37 snubbers) is used for mechanical snubbers based on the large population. The plans, when used in combination, are a conservative approach versus using only the Sample Plan B for the entire population.

Snubber functional testing is performed prior to completion of each refueling outage. This frequency is based on engineering experience and is reasonable for testing of a representative sample of snubbers. Credit may be taken toward meeting minimum outage testing requirements for mechanical snubbers functionally tested within the refueling cycle. Snubbers may be removed from service for functional testing in MODES 1 through 4 provided that the following administrative controls are implemented:

1. Required Actions and Completion Times must be met.

2. No more than one snubber may be removed from service at a time on any line and attached piping which is analyzed as a seismic subsystem. Multiple snubbers may be removed for testing simultaneously only if separated by two or more seismic anchors.

3. Snubbers on trained systems or portions of systems may be removed only on the train which is undergoing maintenance in that work week. Snubbers on non-trained systems or portions of systems may only be removed following a documented risk assessment. Snubbers may not be removed from service for testing on one train of a system while the other train has been declared inoperable for any reason.

4. Snubbers adjacent to equipment nozzles may not be removed for testing except in MODES 5 and 6. In determining the applicability of this limitation, engineering judgment must be used regarding the placement of the snubber relative to the nozzle, the routing of the affected piping, and any other supports available to protect equipment function.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.3.4

The TSR is preceded by three Notes which underline the need for considering service life of sub-components and to replace these sub-components before the end of the respective service lives. The replacement of sub-components must be documented and the documentation retained for further reference. TSR 3.7.3.4 addresses the monitoring of the service life of the snubbers. The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. The expected service life is established by the manufacturer and is based on operating experience with critical snubber parts such as seals and springs in a radiation environment. The every refueling outage Frequency is based on engineering experience and is reasonable for the verification service life.

REFERENCES

1. ASME Boiler and Pressure Vessel Code, Section III and XI.
2. Regulatory Guide 1.124, “Design Limits and Loading Combinations for Class 1 Linear-Type Component Supports.”
3. Regulatory Guide 1.130, “Design Limits and Loading Combinations for Class 1 Plate-and-Shell-Type Component Supports.”
4. “Zion Probabilistic Safety Study,” Commonwealth Edison Company, September 1981.
5. “Millstone Unit 3 Probabilistic Safety Study,” North-east Utilities Company, August 1983.
6. NRC Staff Review of Nuclear Steam Supply System Vendor Owners Groups' Application of The Commission's Interim Policy Statement Criteria to Standard Technical Specifications, Attachment to letter dated May, 1988 from T. E. Murley, NRC to W. S. Wilgus, Chairman The B&W Owners Group.
7. Regulatory Guide 8.8, “Information Relevant to Maintaining Occupational Radiation Exposure as Low as Practicable.”
8. Regulatory Guide 8.10, “Operating Philosophy for Maintaining Occupational Radiation Exposure as Low as Practicable.”
9. SA/SE WBPLCE-97-028-0, RIMS T28970829803.
10. Screening Review WBPLCE-02-003-0.

B 3.7 PLANT SYSTEMS

B 3.7.4 Sealed Source Contamination

BASES

BACKGROUND	A sealed source is any byproduct, source, or special nuclear material that is encased in a capsule designed to prevent leakage or escape of the material (Refs. 1 & 5). Sealed sources are classified into three groups according to their use (sources in use, not in use, and startup sources and fission detectors) and may contain alpha, beta, gamma, or neutron emitting material. The limitations on removable contamination for sources requiring leak testing, including alpha emitters, are based on References 3 & 5. Those sources that are frequently handled are required to be tested more often than those which are not. Sealed sources which are continuously enclosed within a shielded mechanism (i.e., sealed sources within radiation monitoring, excore fission detector assemblies or boron measuring devices) are considered to be stored and need not be tested unless they are removed from the shielded mechanism.
APPLICABLE SAFETY ANALYSES	The sealed source contamination requirement ensures that leakage from sealed sources will not exceed allowable intake values. This TR is important to the safety of plant personnel, however it is not required to mitigate the consequences of a DBA or transient (Refs. 4 & 5).
TR	TR 3.7.4 requires that the removable contamination shall be less than 0.005 microcuries for each sealed source containing the following radioactive material: a. Greater than 100 microcuries of beta and/or gamma emitting material; or b. Greater than 5 microcuries of alpha emitting material.
APPLICABILITY	Since the limits on the removable contamination for each sealed source containing radioactive material are not MODE dependent, this TR is applicable at all times.

BASES (continued)

ACTIONS

Since this TR is applicable at all times, the Required Actions have been modified by a Note stating that the provisions of TR 3.0.3 do not apply.

A.1

With a sealed source having removable contamination in excess of the limits, the sealed source should be withdrawn from use immediately. The immediate Completion Time reflects the importance of preventing the contamination from spreading.

A.2.1 and A.2.2

If the sealed source contamination is not within the specified limit and the sealed source has been removed from use, the sealed source must be decontaminated and repaired, otherwise, disposal of the sealed source is required. If the sealed source is to be decontaminated and repaired, it must be done prior to returning the sealed source to use. If disposal of the sealed source is to be done, it must be completed in accordance with NRC regulations.

TECHNICAL SURVEILLANCE REQUIREMENTS

Notes have been added to this section stating that the licensee or other persons specifically authorized by the NRC shall perform the TSRs, and that the test methods used shall have a detection sensitivity of greater than or equal to 0.005 microcurie per test sample.

TSR 3.7.4.1

This surveillance determines every 6 months that the removable contamination is less than 0.005 microcuries for each sealed source. The 6 month Frequency is frequent enough to identify a leaking or contaminated sealed source without having extensive spreading of contamination.

This surveillance is modified by several Notes. The Notes state that this TSR is only applicable to sources in use, to sources with half-lives of more than 30 days, and to sources in any form other than gas. Also, this TSR is not applicable to startup sources and fission detectors previously subjected to core flux.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.7.4.2

This surveillance determines within 6 months prior to use or transfer to another licensee that the removable contamination is less than 0.005 microcuries for each sealed source and fission detector. This Frequency is adequate to identify a leaking or contaminated sealed source or fission detector to avoid extensive contamination.

This surveillance is modified by two Notes. The first Note states that this TSR is only applicable to sealed sources not in use. The second Note states that sealed sources and fission detectors transferred without a certificate indicating the last test date shall be tested prior to being placed in use.

TSR 3.7.4.3

This surveillance determines that the removable contamination is less than 0.005 microcuries for each startup source and fission detector. This test should be performed on each startup source and incore fission detector within 31 days prior to being installed in the core or being subjected to core flux. It also should be performed following any repairs or maintenance to the source. This Frequency ensures that the startup source or fission detector is not leaking or contaminated over the specified limit.

This Surveillance is modified by a Note stating this TSR only applies to startup sources and incore fission detectors that are not in use.

TSR 3.7.4.4

This surveillance determines that the removable contamination is less than 0.005 microcuries for each excore fission detector. This test should be performed on each excore fission detector assembly within 31 days prior to the detector assembly being installed in its permanent configuration. It also should be performed following any repairs or maintenance to the detector assembly. This frequency ensures that the excore detectors are not leaking or contaminated over the specified limit.

This Surveillance is modified by a Note stating this TSR only applies to excore fission detectors.

BASES (continued)

REFERENCES

1. 10 CFR 30.4 “Definitions,” as clarified by Reference 5.

2. 10 CFR 40.4 “Definitions,” as clarified by Reference 5.

3. 10 CFR 70.4, “Definitions,” as clarified by Reference 5.

4. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 5.

5. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM), dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.7 PLANT SYSTEMS

B 3.7.5 Area Temperature Monitoring

BASES

BACKGROUND

Thermal-life of various electrical and mechanical equipment is one of several important aging concerns in the qualification of hardware. The requirement is that the equipment remains functional during and after specified design basis events. Design basis events consist of loss of offsite power and design basis accidents (DBA). In general, the following three groups of hardware are subjected to qualification:

a. Safety related equipment,

b. Non-safety related equipment (failure of which could prevent safety related equipment to operate as designed), and

c. Specific post-accident monitoring equipment.

The normal service temperatures of concern are relatively low, hence, most of the equipment requiring consideration are components in the electrical power supply and the instrumentation systems. Some of these components are designed for relatively low temperature with very little margin to normal operating temperatures in cabinets and buildings. The procedure for thermal qualification is normally to subject prototypes from the production line to life tests by natural or artificial (accelerated) aging to its end-of-installed life condition. Analyses with justifications of methods and assumptions are used to qualify the prototypes to the actual service conditions, which may differ from the test conditions. Although the equipment is qualified for an environment expected after a DBA, the components are only subjected to normal operating conditions for most of the design life. Therefore, the thermal aging due to normal operating conditions is of major importance and is the parameter which is controlled by the Technical Requirements. Accordingly, this particular requirement establishes temperature limits during normal operation for specific locations in various buildings, except the containment. The temperature limits are related to the expected thermal-life for the hardware which operates in the areas where the temperatures are monitored and controlled.

(continued)

BASES

BACKGROUND (continued)

Due to valve design, ambient temperatures can affect the setpoints of the main steam safety valves (MSSVs), whereby a decrease in valve body temperature causes an increase in setpoint, resulting in non-conservative relief pressure. Ambient temperatures are monitored within the main steam valve vaults to ensure that the MSSVs minimum temperatures are maintained to meet the 1% code allowable variance on setpoints. Detailed BASES for the MSSVs is provided in Technical Specification B 3.7.1.

The general guidelines, which are followed for the qualification of electrical equipment, are provided in 10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants" (Ref. 1). Detailed requirements for the implementation of the general guidelines are provided in various Regulatory Guides and IEEE Standards. Basic requirements for the qualification of mechanical equipment are outlined in General Design Criteria 4 (Ref. 2).

APPLICABLE SAFETY ANALYSES

Certain components, which have the service temperatures controlled by this requirement, are part of the primary success path and function to mitigate DBAs and transients. However, the integrity/OPERABILITY of these components is addressed in the relevant specifications that cover individual components. The service temperatures and the thermal aging, which are controlled by observing the requirements of this TR, are not inputs to the safety analysis. Further, Probabilistic Risk Assessment studies, performed to date, do not explicitly model the function of area temperature monitors. In addition, this particular requirement covers only service temperatures and thermal aging of these components, which are not considerations in designing the accident sequences for theoretical hazard evaluations (Refs. 3 & 4).

TR

TR 3.7.5 provides nominal temperature limits in the vicinity of major equipment. The TR allows for each area shown in Table 3.7.5-1 to be higher or lower than the normal limit for a maximum of eight hours. Note that the temperature values listed in Table 3.7.5-1 do not account for instrument error.

APPLICABILITY

The limits on temperature and time apply whenever the affected equipment in an affected area is required to be OPERABLE.

BASES (continued)

ACTIONS

A.1

Whenever the temperature in one or more areas has exceeded the normal temperature limits for more than eight hours, document the exceedance in accordance with the Corrective Action Program. The report must contain the cumulative time and the amount by which the temperature has exceeded the limits.

Condition A has been modified by a Note stating that the provisions of TR 3.0.3 do not apply.

B.1.1, B.1.2, and B.2

Whenever the temperature in one or more areas has exceeded the abnormal temperature limits, the temperature must be restored to within the normal limits in 4 hours. The Completion Time of 4 hours is based on operator experience and is a reasonable time for restoring the temperature. Alternatively, the affected equipment must be declared inoperable and the inoperability documented in accordance with the Corrective Action Program along with the cumulative time and the amount by which the temperature has exceeded the limits. In addition, an analysis shall be prepared which demonstrates OPERABILITY of the affected equipment.

C.1 and C.2

Whenever the temperature in the Intake Pumping Station mechanical or electrical equipment rooms exceeds the lower limit of 40 °F, actions must be initiated within 24 hours to ensure the temperature does not decrease below 32 °F. The 24 hour Completion Time hours is based on temperature analysis. Within 7 days, restore normal temperatures within the areas affected. The 7 day Completion Time is based on a reasonable repair duration, and compensatory actions available during the interim period to maintain temperatures above 32 °F.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

If the temperature in the Intake Pumping Station mechanical or electrical equipment rooms decreases to 32 °F or lower, the affected equipment must be immediately declared inoperable. The Completion Time is based on potential freezing of safety-related components. The inoperability of the equipment must be documented in the Corrective Action Program along with the cumulative time and amount by which the temperature has exceeded the limits. In addition, an analysis shall be submitted which demonstrates OPERABILITY of the affected equipment.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.7.5.1

The temperatures for the areas listed in Table 3.7.5-1 must be determined every 12 hours to ensure compliance with the limits. The 12 hour Frequency is based on engineering experience and is reasonable considering the time required for performing the surveillance and the probability for changes in the area temperatures. Note that the temperature values listed in Table 3.7.5-1 do not account for instrument error.

REFERENCES

1. 10 CFR 50.49 "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants."

2. 10 CFR 50, Appendix A, General Design Criteria 4, "Environmental and Dynamic Effects Design Bases."

3. WCAP-11618, "MERITS Program-Phase II, Task 5, Criteria Application," including Addendum 1 dated April, 1989, as clarified by Reference 4.

4. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM), dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 Isolation Devices

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided by trains into two redundant and independent AC and DC electrical power distribution subsystems. Each AC and DC electrical power distribution subsystem is comprised of 6.9kV AC shutdown boards, 480V AC shutdown boards, associated motor control centers, and 120V AC power distribution panels, 120V AC vital buses, and 125V DC vital buses. Two trains (or subsystems) are required for safety function redundancy; any one train provides safety function, but without worst-case single-failure protection.

Because of the safety significance of the Class 1E AC and DC electrical power distribution subsystems and the equipment that they supply, unique requirements for OPERABILITY are imposed on these subsystems beyond those requirements applicable to non-qualified AC and DC distribution subsystems. As such, 1E buses must be protected from faults that could occur on loads not included as part of the Class 1E system, associated nonqualified cables routed in Class 1E cable trays or nonqualified cables insufficiently separated from Class 1E cables. Circuit breakers actuated by fault currents are used as isolation devices in this plant to detect and isolate faults. The OPERABILITY of these circuit breakers ensures that the Class 1E buses will be protected in the event of faults in nonqualified loads powered by the buses, located in associated nonqualified cables routed in Class 1E cable trays or in nonqualified cables insufficiently separated from Class 1E cables.

APPLICABLE SAFETY ANALYSES

The initial conditions of design basis transient and accident analyses in FSAR Chapter 6, “Engineered Safety Feature,” and Chapter 15, “Accident Analyses” (Ref. 1) assume ESF Systems are OPERABLE. The Class 1E 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 (RCS) and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Technical Specifications 3.2 (Power Distribution Limits), 3.4 (Reactor Coolant System), and 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 (Ref. 1) and is based upon meeting the design basis of the plant. This includes maintaining at least one train of the onsite or offsite AC electrical power sources, DC electrical power sources, and associated distribution systems OPERABLE during accident conditions in the event of:

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

b. A worst-case single failure.

Isolation devices help ensure the OPERABILITY of Class 1E AC and DC electrical power distribution systems by protecting them from faults on the non-Class 1E portion of the distribution system, on associated nonqualified cables routed in Class 1E cable trays, or on nonqualified cables insufficiently separated from Class 1E cables. However, these devices are not a structure, system, or component that is part of the primary success path and which actuates to mitigate a DBA or transient that either assumes a failure of or presents a challenge to the integrity of a fission product barrier (Ref. 2).

TR

TR 3.8.1 requires that all circuit breakers actuated by fault currents that are used as isolation devices protecting Class 1E buses from non-qualified loads, associated circuits or insufficiently separated cables shall be OPERABLE. These breakers are identified on Drawing Series 45A710 (Ref. 3). This Technical Requirement satisfies testing specified in Sections 8.3.3.3 (2) and 8.3.3.3 (3) of the Safety Evaluation Report (Ref. 4). The OPERABILITY of these devices helps ensure that the Class 1E subsystem will be protected from faults that occur on the non-Class 1E portion of the distribution system.

APPLICABILITY

The Class 1E AC and DC electrical distribution systems are required to supply power to those systems necessary to mitigate the consequences of DBAs or transients that could occur in MODES 1, 2, 3, or 4. Isolation devices are therefore required to protect the Class 1E distribution systems in these MODES.

BASES (continued)

ACTIONS

A.1, A.2.1, and A.2.2

With one or more of the required circuit breakers inoperable, the Class 1E distribution system is not isolated from faults on non-Class 1E portions of the distribution system, on non-Class 1E associated cables routed in Class 1E cable trays, or on Non-Class 1E cables insufficiently separated from Class 1E cables.

Action must be taken to restore this isolation. One possible solution is to restore the circuit breaker(s) to OPERABLE status. If this cannot be done, the isolation can be achieved manually by tripping or removing the inoperable circuit breaker(s). Removing the inoperable breaker(s) ensures that they will not be inadvertently closed before they can be restored to OPERABLE status. The Completion Time of 8 hours takes into consideration the low probability of a fault occurring on the distribution system, on an associated non-Class 1E circuit or on an insufficiently separated non-Class 1E cable, concurrent with an event requiring the safety systems supplied by the Class 1E system. It also represents a reasonable time to repair or trip (or remove) the inoperable circuit breaker(s).

To ensure that the inoperable circuit breaker(s) are not inadvertently re-energized before they are returned to OPERABLE status, it is necessary to periodically verify that they remain tripped or removed. The period of 7 days takes into consideration the unlikelihood that a plant operation or maintenance activity would result in the re-energization of these breaker(s) from the de-energized condition.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A cannot be met, the Class 1E system remains unprotected from faults on non-Class 1E portions of the distribution system, on non-Class 1E associated cables routed in Class 1E cable trays or on non-Class 1E cables insufficiently separated from Class 1E cables. Since this condition cannot be allowed for an extended period of time, it is necessary to place the plant in a condition where the isolation devices are not required to be OPERABLE. This is done by placing the plant in MODE 3 in 6 hours and then in MODE 5 in the next 30 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.

BASES (continued)

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.8.1.1

This surveillance requires the performance of a functional test on a representative sample of ≥ 10% of each type of molded-case circuit breaker used as an isolation device. This sample size is sufficiently large to represent the actual failure distribution within the whole population of circuit breakers of a given type used in the plant. If there are any failure mechanisms that could affect the OPERABILITY of the circuit breaker(s) they are likely to have occurred in the sample tested. The 18 month Frequency takes into consideration the infrequent operation of the breakers and their correspondingly low failure rate. The Surveillance is augmented by three Notes. The first Note states that the breakers shall be selected for testing on a rotating basis. This ensures that all of the breakers will eventually be tested and those failures that may not have been discovered in the initial 10% samples will eventually be discovered.

The second Note describes the functional test procedure and the response to be verified to ensure OPERABILITY.

The third Note states that for each molded case circuit breaker found inoperable during functional tests an additional representative sample of 10% of the defective type shall be functionally tested until no more failures are found or all of that type have been functionally tested. This helps to ensure that a failure discovered in the representative sample was not caused by a failure mechanism that could systematically affect other breakers in the overall population of breakers of the same type.

TSR 3.8.1.2

This surveillance requires the performance of a functional test on a representative sample of ≥ 10% of each type of electrically-operated circuit breaker used as an isolation device. This sample size is sufficiently large to represent the actual failure distribution within the whole population of circuit breakers of a given type used in the plant. If there are any failure mechanisms that could affect the OPERABILITY of the circuit breaker(s), they are likely to have occurred in the sample tested. The 18 month Frequency takes into consideration the infrequent operation of the breakers and their correspondingly low failure rate.

The Surveillance is augmented by three Notes. The first Note states that the breakers shall be selected for testing on a rotating basis. This ensures that all of the breakers will eventually be tested and those failures that may not have been discovered in the initial 10% samples will eventually be discovered. The second Note describes the functional test procedure and the response to be verified to ensure OPERABILITY.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.8.1.2 (continued)

The third Note states that for each electrically-operated circuit breaker found inoperable during functional tests an additional representative sample of 10% of the defective type shall be functionally tested until no more failures are found or all of that type have been functionally tested. This helps to ensure that a failure discovered in the representative sample was not caused by a failure mechanism that could systematically affect other breakers in the overall population of breakers of the same type.

TSR 3.8.1.3

This surveillance requires that the performance of a CHANNEL CALIBRATION of all protective relays associated with medium voltage (6.9 kV) isolation overcurrent devices. A CHANNEL CALIBRATION assures that the relays will be able to detect overcurrent conditions on the non-Class 1E loads. The Frequency of 18 months is consistent with the typical industry refueling cycle.

TSR 3.8.1.4

This surveillance requires the performance of an integrated system functional test which verifies that the relays and associated medium voltage (6.9 kV) circuit breakers function as designed to isolate fault currents. An integrated test assures that the individual elements of the protection scheme, the relays, breakers and other control circuits, interact as designed.

The surveillance has been modified by a Note stating that if a failure is discovered in the integrated functional test, an additional representative sample of at least 10% of all the circuit breakers of the inoperable type shall also be tested to assure that there is no common cause failure mechanism that could systematically affect all breakers of a given type.

The Frequency of 18 months coincides with the typical industry refueling cycle.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.8.1.5

This surveillance requires the inspection of each circuit breaker and the performance of procedures prepared in conjunction with the manufacturer's recommendations. By performance of recommended maintenance, the likelihood for the circuit breakers to become inoperable can be minimized. The 72 months periodicity for Class 1E circuit breaker, (Ref. 5), takes into consideration the low frequency of operation of the circuit breakers and the low likelihood that operation and maintenance activities at the plant could adversely affect the OPERABILITY of the circuit breaker.

REFERENCES

1. Watts Bar FSAR, Section 6.0, “Engineered Safety Feature,” and Section 15.0, “Accident Analyses.”

2. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM), dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

3. Watts Bar Wiring Diagram Series 45A710, “Periodic Breaker Test.”

4. NUREG-0847, “Safety Evaluation Report Related to the Operation of Watts Bar Nuclear Plant, Units 1 and 2” including Supplements thereto.

5. EPRI NP-7410-V3, “Molded Case Circuit Breaker Application and Maintenance Guide,” Revision 1.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 Containment Penetration Conductor Overcurrent Protection Devices

BASES

BACKGROUND

General Design Criterion (GDC), “Containment Design Basis,” of 10 CFR 50, Appendix A requires, in part, that the reactor containment structure be designed so that the containment structure can, without exceeding design leakage rate, accommodate the calculated pressure, temperature, and other environmental conditions resulting from any loss-of-coolant accident. One consideration in meeting the requirements of this GDC is the design of electrical penetrations.

Reference 1 describes a method of complying with GDC Appendix A with respect to the requirements for design, qualification, construction, installation and testing of electric penetration assemblies. It specifies that the electric penetration assembly should be designed to withstand, without loss of mechanical integrity, the maximum short-circuit current vs. time conditions that could occur given single random failures of circuit overload protection devices.

The function of electrical protective devices is to detect and isolate faults that could occur on the electrical distribution system. These devices therefore provide an effective means of preventing fault currents from challenging the design limit of the penetrations. Containment penetration conductor overcurrent protective devices are installed to further protect the penetration conductors from faults on components inside containment or improper operation of other protective devices in addition to that provided by the distribution system.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment includes the requirement that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate. The design of the electrical penetrations must therefore provide that they remain intact in the event of faults on components inside containment or penetration conductors that supply these components. The containment penetration conductor overcurrent protective devices provide additional fault protection of the penetrations and help ensure that the design limits of the penetrations are not challenged. However, these overcurrent protective devices are not a structure, system, or component that is part of the primary success path and which actuates to mitigate a DBA or transient that either assumes a failure of or presents a challenge to the integrity of a fission product barrier (Refs. 2 & 5).

BASES (continued)

TR

TR 3.8.2 requires that all containment penetration conductor overcurrent protection devices be OPERABLE. These protection devices are identified on Drawing Series 45A710 (Ref. 3). This assures that the design limits of the containment electrical penetrations will not be challenged as a result of electrical faults on the penetration conductors or the equipment that they supply in containment.

APPLICABILITY

The OPERABILITY of the containment penetration conductor overcurrent protection devices is required when the containment is required to be OPERABLE. In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced because of the pressure and temperature limitations of these MODES. The containment penetration conductor overcurrent protection devices are, therefore, required to be OPERABLE in MODES 1, 2, 3, and 4.

ACTIONS

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

With one or more containment penetration conductor overcurrent protection devices inoperable, the circuit(s) associated with the inoperable protection device(s) must be placed in a condition that would preclude the possibility of a fault that could overload the circuit(s). To accomplish this, the circuit is de-energized by either tripping the circuit's backup circuit breaker or by removing the inoperable circuit breaker. Since systems or components supplied by the affected circuit will no longer have power, they must be declared inoperable.

The 72 hour Completion Time takes into account the design of the electrical penetration for maximum fault current, the availability of backup circuit protection on the distribution system and the low probability of a DBA occurring during this period. This Completion Time is also considered reasonable to perform the necessary repairs or circuit alterations to restore or otherwise de-energize the affected circuit.

In order to assure that any electrical penetration which is not protected by an overcurrent device remains de-energized, it is necessary to periodically verify that its backup circuit breaker is tripped or that the inoperable circuit breaker is removed. A Completion Time of 7 days is considered sufficient due to the infrequency of plant operations that could result in reenergizing a circuit that has been de-energized in this manner.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable containment penetration conductor overcurrent protection devices are not able to be restored to OPERABLE status and the associated circuit cannot be de-energized within 72 hours, the containment penetration is vulnerable to the mechanical effects of a short circuit, should one occur. These effects can challenge the design capability of the penetration and therefore pose a threat to containment integrity. To protect against this possibility, the plant must be placed in a condition where the TR is not applicable. This is done by placing the plant in MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are considered reasonable based on operating experience to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

TECHNICAL SURVEILLANCE REQUIREMENTS

As described by Technical Surveillance Requirements general surveillance Note 1, the surveillances for this TR are necessary to assure that the overcurrent protection devices given in Drawing Series 45A710 (excluding fuses) are demonstrated OPERABLE. Note 2 explains that the surveillance requirements apply to at least one Reactor Coolant Pump (RCP) such that all RCP circuits are demonstrated OPERABLE at least once per 72 month period. This recognizes the importance of the RCP circuits to the safe operation of the plant as well as the potentially large amount of short circuit current associated with a fault on these circuits.

TSR 3.8.2.1

This surveillance requires the performance of a CHANNEL CALIBRATION of all protective relays associated with medium voltage (6.9 kV) containment penetration overcurrent devices. A CHANNEL CALIBRATION assures that the relays will be able to detect overcurrent conditions on the penetration conductors. The Frequency of 18 months is consistent with the typical industry refueling cycle.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.8.2.2

This surveillance requires the performance of an integrated system functional test which verifies that the relays and associated medium voltage (6.9 kV) circuit breakers function as designed to isolate fault currents. An integrated test assures that the individual elements of the protection scheme, the relays, breakers and other control circuits, interact as designed.

The surveillance has been modified by a Note stating that if a failure is discovered in the integrated functional test, an additional representative sample of at least 10% of all the circuit breakers of the inoperable type shall also be tested to assure that there is no common cause failure mechanism that could systematically affect all breakers of a given type.

The Frequency of 18 months coincides with the typical industry refueling cycle.

TSR 3.8.2.3

This surveillance requires the performance of a functional test on a representative sample of ≥ 10% of each type of molded-case circuit breaker used as penetration protection. This sample size is sufficiently large to represent the actual failure distribution within the whole population of circuit breakers of a given type used in the plant. If there are any failure mechanisms that could affect the OPERABILITY of the circuit breaker(s) they are likely to have occurred in the sample tested. The 18 month Frequency takes into consideration the infrequent operation of the breakers and their correspondingly low failure rate. The Surveillance is augmented by three Notes. The first Note states that the breakers shall be selected for testing on a rotating basis. This ensures that all of the breakers will eventually be tested and those failures that may not have been discovered in the initial 10% samples will eventually be discovered.

The second Note describes the functional test procedure and the response to be verified to ensure OPERABILITY.

The third Note states that for each molded case circuit breaker found inoperable during functional tests an additional representative sample of 10% of the defective type shall be functionally tested until no more failures are found or all of that type have been functionally tested. This helps to ensure that a failure discovered in the representative sample was not caused by a failure mechanism that could systematically affect other breakers in the overall population of breakers of the same type.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.8.2.4

This surveillance requires the performance of a functional test on a representative sample of ≥ 10% of each type of electrically-operated circuit breaker used as penetration protection. This sample size is sufficiently large to represent the actual failure distribution within the whole population of circuit breakers of a given type used in the plant. If there are any failure mechanisms that could affect the OPERABILITY of the circuit breaker(s), they are likely to have occurred in the sample tested. The 18 month Frequency takes into consideration the infrequent operation of the breakers and their correspondingly low failure rate.

The Surveillance is augmented by three Notes. The first Note states that the breakers shall be selected for testing on a rotating basis. This ensures that all of the breakers will eventually be tested and those failures that may not have been discovered in the initial 10% samples will eventually be discovered. The second Note describes the functional test procedure and the response to be verified to ensure OPERABILITY.

The third Note states that for each electrically-operated circuit breaker found inoperable during functional tests an additional representative sample of 10% of the defective type shall be functionally tested until no more failures are found or all of that type have been functionally tested. This helps to ensure that a failure discovered in the representative sample was not caused by a failure mechanism that could systematically affect other breakers in the overall population of breakers of the same type.

TSR 3.8.2.5

This surveillance requires the inspection of each circuit breaker and the performance of preventive maintenance in accordance with procedures prepared in conjunction with the manufacturers recommendation. Performance of recommended preventive maintenance helps ensure the operability of the circuit breakers. The 72 months periodicity for Class 1E and 96 months for non-Class 1E circuit breakers (Ref. 4) takes into consideration known failure rates for the circuit breakers and operating experience.

BASES (continued)

REFERENCES

1. Regulatory Guide 1.63, “Electric Penetration Assemblies in Containment Structures for Nuclear Power Plants,” Revision 3.

2. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 5.

3. Watts Bar Wiring Diagram Series 45A710, “Periodic Breaker Test.”

4. EPRI NP-7410-V3, “Molded Case Circuit Breaker Application and Maintenance Guide,” Revision 1.

5. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM), dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Motor Operated Valves Thermal Overload Bypass Devices

BASES

BACKGROUND

Motor operated valves with thermal overload protection devices for the valve motors are used in safety systems and in their auxiliary supporting systems. Operating experience has shown that indiscriminate application of thermal overload protection devices to these valve motors could result in needless hindrance to successful completion of safety functions (Ref. 1).

Thermal overload relays are designed primarily to protect continuous-duty motors while they are running rather than during starting. Use of these overload devices to protect intermittent-duty motors may therefore result in undesired actuation of the devices if the cumulative effect of heating caused by successive starts at short intervals is not taken into account in determining the overload trip setting.

The accuracy obtainable with the thermal overload relay trip generally varies from -5% to 0% of trip setpoint. Since the primary concern in the application of overload devices is to protect the motor windings against excessive heating, the above negative tolerance in trip characteristics of the protection device is considered in the safe direction for motor protection. However, this conservative design feature built into these overload devices for motor protection could interfere in the successful functioning of a safety related system. An improper thermal overload setting could prevent a vital piece of equipment from performing its intended function.

Reference 1 states that one alternative to “ensure that safety-related motor operated valves whose motors are equipped with thermal overload protection devices … will perform their function” is that those thermal overload protection devices that are normally in force during plant operation should be bypassed under accident conditions.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The accident analysis (Ref. 2) assumes the availability of the Engineered Safeguards Features to mitigate the consequences of a DBA or transient. The safety design basis of the containment includes the requirement that the containment must withstand the limiting DBA without exceeding the design leakage rate. Both of these requirements depend upon the actuation of motor-operated valves to perform their safety function. Thermal overload bypasses minimize the probability that a motor-operated valve will fail to perform its intended safety function due to an unnecessary operation of the thermal overload trip device.

However, these thermal overload protective devices are not a structure, system, or component that is part of the primary success path and which actuates to mitigate a DBA or transient that either assumes a failure of or presents a challenge to the integrity of a fission product barrier (Refs. 3 & 4).

TR

TR 3.8.3 requires that all thermal overload bypass devices shall be OPERABLE. The OPERABILITY of the motor-operated valves thermal overload bypass devices ensures that thermal overload devices will not prevent safety-related valves from performing their function.

APPLICABILITY

The OPERABILITY of the motor-operated valves thermal overload bypass devices ensures that these devices will not prevent safety-related valves from performing their function. They therefore help ensure the OPERABILITY of these motor-operated valves and are required to be operable whenever the valves that they are designed to ensure operable are required to be OPERABLE.

BASES (continued)

ACTIONS

A.1 and A.2

With thermal overload protection not bypassed when required for one or more of the valves listed in Table 3.8.3-1, the actuation of the thermal overload trip device could open or remove power from a motor before the safety function has been completed or even started. Providing an alternate means to bypass the thermal overload would effectively prevent the removal of power from a motor by the thermal overload device. An 8 hour Completion Time takes into consideration the low probability of these motor-operated valves being required to operate during this period, and is considered to be a reasonable amount of time to either restore the bypass device to OPERABLE status or provide an alternative means of bypassing the thermal overload device.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A cannot be met, then motor-operated valves with inoperable thermal overload bypass devices cannot be considered OPERABLE. Declaring these valves inoperable and applying the appropriate ACTION statement(s) of the affected systems ensures the inoperability of a bypass device will not result in unacceptable deviations from any TRs or LCOs applicable to their associated valves.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.8.3.1

This surveillance requires that a TADOT be performed every 18 months. This ensures continued functional reliability and accuracy of the trip point. The 18 month Frequency is based upon the known reliability of the thermal overload bypass device and has been shown to be acceptable through operating experience.

REFERENCES

1. Regulatory Guide 1.63, “Electric Penetration Assemblies in Containment Structures for Nuclear Power Plants,” Revision 3.

2. Watts Bar FSAR, Section 15, “Accident Analysis.”

3. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 4.

4. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM), dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 Submerged Component Circuit Protection

BASES

BACKGROUND

Electrical equipment located inside containment has been designed to maintain equipment safety functions and to prevent unacceptable spurious actuations. All power cables feeding equipment inside containment are provided with individual breakers to protect the power sources (both Class 1E and non-Class 1E) from the effects of electrical shorts. Reactor coolant pumps have two circuit breakers. All other power cables are provided with a cable protector fuse which, in the event of a breaker failure, is designed to protect the containment penetration. These breakers and protector fuses ensure that, should an electrical short occur inside containment, the electrical power source will not be affected.

A failure analysis has been made on the ability of the electrical power (both AC and DC) systems to withstand failure of submerged electrical components from the postulated LOCA flood levels inside containment (Ref. 1 and 5). Some of the identified components are automatically de-energized in event of a LOCA. The remaining components that are powered from a Class 1E source were assumed to have a high impedance fault for the analysis. The magnitude of the leakage currents used in the analysis is the maximum value of current that each protective device would carry for an indefinite period (i.e., the protective device's thermal rating). The results of the evaluations indicate that the submergence of electrical components will not prevent the Class 1E electric (either AC or DC) systems from performing their intended safety function for the postulated submerged condition.

A listing of major electrical components located inside containment that may be inundated following a LOCA is found in Reference 2 along with an explanation of the safety significance of the failure of the equipment due to flooding. These components are automatically de-energized by the accident signal and the accident signal must be reset to remove the automatic trip signal from each component.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The Accident Analysis (Ref. 3) assumes the availability of the Engineered Safeguards Features to mitigate the consequences of a DBA or transient. The safety design basis of the containment includes the requirement that the containment must withstand the limiting DBA without exceeding the design leakage rate. Both of these requirements depend upon the actuation of motors and valves to perform their safety function. An electrical or mechanical failure on a submerged component has the potential to interfere with the ability of some other safety component or system to perform its intended function. By de-energizing their associated component on accident conditions, submerged component circuits minimize the potential for this type of interference with safety functions. They are not, however, systems or components that are part of the primary success path and which actuate to mitigate a DBA or transient that either assumes a failure of or presents a challenge to the integrity of a fission product barrier (Refs. 4 & 6).

TR

TR 3.8.4 requires that all submerged component circuits associated with valves 2-FCV-74-1, 2-FCV-74-2, 2-FCV-74-8, and 2-FCV-74-9 shall be de-energized and with each component listed in Table 3.8.4-1 shall be OPERABLE. The OPERABILITY of the submerged component circuits ensures that electrical or mechanical faults on submerged components will not interfere with the ability of other safety related equipment, or the Class 1E distribution, to perform its safety function.

APPLICABILITY

Electrical or mechanical faults on valves 2-FCV-74-1, 2-FCV-74-2, 2-FCV-74-8, and 2-FCV-74-9, and the components listed in Table 3.8.4-1 could potentially affect systems or components necessary to mitigate the consequences of DBAs or transients that could occur in MODES 1, 2, 3, or 4. The submerged component circuits are therefore required to be OPERABLE during these MODES in order to de-energize potentially submerged components.

BASES (continued)

ACTIONS

A.1

With the circuits for valves 2-FCV-74-1, 2-FCV-74-2, 2-FCV-74-8 and 2-FCV-74-9 energized with RCS pressure ≥ 425 psig or with one or more submerged components circuits (Table 3.8.4-1) inoperable, the associated submerged components could remain energized in the event of an accident. In order to prevent the adverse effects of a potential fault on an energized submerged component during an accident, it is necessary to restore the ability to automatically de-energize the component under accident conditions or to maintain a de-energized configuration for components not required to be functional. This can be done by restoring the inoperable circuit to OPERABLE status. The Completion Time of 7 days takes into consideration the low probability of an accident occurring which would cause the components to be submerged. It is a reasonable amount of time to complete the work necessary to restore the circuits to OPERABLE status.

B.1 and B.2

If the submerged component circuits cannot be restored to OPERABLE status within the 7 day Completion Time, it is necessary to place the plant in a Condition where the function of the circuits is not needed. This can be accomplished by first placing the plant in MODE 3 and then in MODE 5. The Completion Time of 6 hours to reach MODE 3 and 36 hours to reach MODE 5 are considered to be reasonable times for placing the plant into a condition where the TR is not applicable in a controlled manner.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.8.4.1

This surveillance requires verification that valves 2-FCV-74-1, 2-FCV-74-2, 2-FCV-74-8, and 2-FCV-74-9 are de-energized by removal of power at the 480V motor control centers. These valves are required to be shut in MODES 1, 2, 3, and 4, and are interlocked so that they cannot be opened until RCS Pressure is reduced to < 425 psig. The Frequency of 31 days is considered reasonable based on plant operating experience.

(continued)

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.8.4.2

This surveillance requires verification that the components shown in Table 3.8.4-1 are automatically de-energized on a simulated accident signal. Since the function of OPERABLE submerged component circuits for the valves shown in the Table is to de-energize the components under accident conditions, verification that the valves are, in fact, de-energized on a simulated accident signal also constitutes verification that the submerged component circuits are OPERABLE. The 18 month Frequency corresponds to the availability of the components for testing during plant refueling.

REFERENCES

1. Watts Bar FSAR, Section 8.3.1.2.3, “Safety-Related Equipment in a LOCA Environment.”

2. Watts Bar FSAR, Table 8.3-28, “Major Electrical Equipment That Could Become Submerged Following a LOCA.”

3. Watts Bar FSAR, Section 15.0, “Accident Analyses.”

4. WCAP-13470, “Watts Bar Unit 1 Technical Specifications Criteria Application Report,” dated August, 1992, as clarified by Reference 6.

5. Watts Bar Electrical Calculation EDQ00299920080020.

6 TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM), dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.9 REFUELING OPERATIONS

B 3.9.1 RESERVED FOR FUTURE ADDITION

B 3.9 REFUELING OPERATIONS

B 3.9.2 Communications

BASES

BACKGROUND	During CORE ALTERATIONS communication ability must be retained between the control room and personnel on the refueling station. This is needed to allow the refueling personnel to be informed of any significant changes in the unit status or core reactivity conditions.
APPLICABLE SAFETY ANALYSES	This requirement helps assure direct communications between the control room and refueling personnel during refueling, which would help to preclude inadvertent criticality. It also ensures that the refueling personnel are able to inform the control room if there are any problems or accidents during the refueling process. Refueling operations are not addressed in PRA studies and would not be important in accident sequences that are commonly found to dominate risk (Ref. 1).
TR	TR 3.9.2 requires that direct communications be maintained between the control room and personnel at the refueling station. This ensures that information can be exchanged between the two groups if any unplanned events occur or if any significant changes occur in the unit status or core reactivity conditions.
APPLICABILITY	TR 3.9.2 is only applicable during CORE ALTERATIONS (MODE 6). In all other MODES refueling procedures do not take place and are therefore not applicable.

BASES (continued)

ACTIONS

A.1

If direct communications between the control room and the personnel at the refueling station cannot be maintained, all CORE ALTERATIONS must be suspended immediately. This is to ensure that the unit remains in a safe condition and that the workers are not placed in an unsafe situation.

Suspension of CORE ALTERATIONS shall not preclude completion of actions to establish a safe condition.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.9.2.1

TSR 3.9.2.1 requires that a demonstration be made to verify that direct communications between the control room and personnel at the refueling station are established. The Surveillance is to be performed within 1 hour prior to the start of the CORE ALTERATIONS and every 12 hours during the CORE ALTERATIONS. The Frequency of 12 hours is based on engineering judgment and on the very small likelihood of the communication abilities being broken.

REFERENCES

1. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Refueling Machine

BASES

BACKGROUND

The refueling machine is used during CORE ALTERATIONS to either move fuel assemblies to new positions in the core, load new fuel assemblies, or unload spent fuel assemblies. The refueling machine consists of a rectilinear bridge and trolley crane with a vertical mast extending down into the refueling water. The bridge and trolley motions are used to position the vertical mast over a fuel assembly in the core. A long tube with a pneumatic gripper on the end is lowered down out of the mast to grip the fuel assembly and manipulate it so that it can be transported to its new position.

The refueling machine has two auxiliary monorail hoists which are located on each side of the bridge. The auxiliary hoists are used for the movement of control rod drive shafts in order to facilitate the refueling process. Before using the hoist, the drive shafts must be disconnected from their respective control rods and, with the upper internals, removed from the vessel (Ref. 1).

APPLICABLE SAFETY ANALYSES

This requirement ensures that the refueling machine and auxiliary hoists have sufficient load capacity to lift a fuel assembly or a drive shaft, respectively. This is to prevent a load from being accidentally dropped during the refueling process. The requirement also ensures that load limiting devices are available to prevent damage to a fuel assembly during fuel movement. These requirements have not been identified as a significant risk contributor (Refs. 2 & 3).

TR

TR 3.9.3 requires that the refueling machine and auxiliary hoist shall be used for the movement of fuel assemblies or drive shafts and that they shall be OPERABLE with certain requirements as discussed below. The refueling machine shall have a capacity of at least 3150 pounds, with two electrical overload cutoff limits of 2650 pounds, and 2800 pounds, respectively.

(continued)

BASES

TR (continued)

(Although the manufacturer's dynamic capacity rating of the refueling machine is 4000 pounds, only a capacity of 3150 pounds is required for movement of fuel assemblies or drive shafts). The auxiliary hoist shall have a capacity of at least 1200 pounds and a load indicator which shall be used to prevent the lifting of loads which are greater than 1190 pounds. These load requirements are specified in order to ensure that the equipment can handle the nominal weights of the components it must manipulate, while assuring that core components are not damaged from excessive lifting forces.

APPLICABILITY

TR 3.9.3 is applicable only during the movement of fuel assemblies or drive shafts within the reactor pressure vessel. The refueling machine's and auxiliary hoist's maximum loads and limitations are required when used for these purposes only, so the requirements are not applicable at any other times.

ACTIONS

A.1

If the refueling machine does not meet the requirements above, it is considered inoperable. Therefore, its use involving the movement of fuel assemblies within the reactor pressure vessel must be suspended immediately.

Suspension of the refueling operations shall not preclude completion of actions to establish a safe condition.

B.1

If the auxiliary hoist does not meet the requirements above, it is considered inoperable. Therefore, its use involving the movement of drive shafts within the reactor pressure vessel must be suspended immediately.

Suspension of the refueling operations shall not preclude completion of actions to establish a safe condition.

BASES (continued)

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.9.3.1

TSR 3.9.3.1 requires the performance of three tests on the refueling machine. A load test of 3150 pounds must be performed on the refueling machine to verify its capacity. A test must be performed to demonstrate an automatic electrical load cutoff before the crane load is greater than 2650 pounds. A test must also be performed to demonstrate a second automatic electrical load cutoff before the crane load is greater than 2800 pounds. These tests verify that the capacity and the load limits are still within the Technical Requirements. The Surveillance Frequency of 18 months is based upon engineering judgment, manufacturer recommendation, the fact that the refueling machine is an infrequently used and highly reliable piece of equipment, and consistency with the typical industry refueling cycle.

TSR 3.9.3.2

TSR 3.9.3.2 requires a load test of at least 1200 pounds be performed on each required auxiliary hoist and its associated load indicator. This test verifies that the capacity is within the Technical Requirement and that the load indicator is functional. This surveillance is to be performed within 100 hours prior to starting the movement of the drive shafts within the reactor pressure vessel. The surveillance frequency is based on engineering judgment and the fact that the auxiliary hoist is an infrequently used and reliable piece of equipment.

REFERENCES

1. Watts Bar FSAR, Section 9.1.4, “Fuel Handling System.”

2. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 3.

3. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM),” dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

B 3.9 REFUELING OPERATIONS

B 3.9.4 Crane Travel - Spent Fuel Storage Pool Building

BASES

BACKGROUND

The spent fuel pool is a reinforced concrete structure with a stainless steel liner for leak tightness. The spent fuel storage racks consist of stainless steel structures with receptacles for nuclear fuel assemblies as they are used in a reactor, receptacles for neutron poison assemblies, and a supporting structure. Design of these storage racks is in accordance with Reference 1.

The racks can withstand the drop of a fuel assembly from its maximum supported height and the drop of tools used in the pool. Crane travel in the spent fuel storage pool building is limited through electrical and mechanical stops which prevent the movement of heavy objects, including shipping casks, over the spent fuel pool. The movement of casks is restricted to the cask loading area and areas away from the pool (Ref. 2).

APPLICABLE SAFETY ANALYSES

The release of radioactive material from fuel may occur during the refueling process, and at other times, as a result of fuel-cladding failures or mechanical damage caused by the dropping of fuel elements or the dropping of objects onto fuel elements (Ref. 1). The restriction on the movement of loads in excess of the nominal weight of a fuel and control rod assembly and the associated handling tool over other fuel assemblies in the storage pool areas ensures that, in the event this load is dropped, the activity release will be limited to that contained in a single fuel assembly, and that any possible distortion of fuel in the storage racks will not result in a critical array. These are design basis type accidents that have not been significant to risk when analyzed in environmental reports (Refs. 3 & 4).

TR

TR 3.9.4 requires that loads greater than 2059 pounds shall be prohibited from travel over fuel assemblies in the spent fuel pool. This ensures that objects traversing the pool are within the design basis and will not cause an unsafe condition if accidentally dropped.

BASES (continued)

APPLICABILITY

TR 3.9.4 is applicable only when fuel assemblies are in the spent fuel pool. If there are no fuel assemblies in the pool, there is no danger of damaging a fuel assembly with a dropped load, therefore, the TR does not apply. The Applicability has been modified by a Note stating that the provisions of TR 3.0.3 do not apply.

ACTIONS

A.1

If a load in excess of 2059 pounds is allowed to traverse fuel assemblies in the spent fuel pool, the load must immediately be placed in a safe condition. This entails moving the load to a position which is not over the spent fuel pool.

TECHNICAL SURVEILLANCE REQUIREMENTS

TSR 3.9.4.1

TSR 3.9.4.1 requires that the crane interlocks and physical stops, which prevent crane travel over fuel assemblies, are demonstrated to be OPERABLE. This surveillance must be performed within 7 days prior to using the crane and at least once per 7 days thereafter during crane operation. The 7 day Frequency corresponds to ANSI B30.2, “Frequent Inspection for Heavy to Severe Service.”

REFERENCES

1. Regulatory Guide 1.13, “Spent Fuel Storage Facility Design Basis.”
2. Watts Bar FSAR, Section 9.1.2, “Spent Fuel Storage.”
3. WCAP-11618, “MERITS Program-Phase II, Task 5, Criteria Application,” including Addendum 1 dated April, 1989, as clarified by Reference 4.
4. TVA letter, “Watts Bar Nuclear Plant (WBN) Unit 1 - Technical Requirements Manual (TRM),” dated August 27, 1992 (ADAMS Accession No. ML073230174) including Enclosure 1, “Watts Bar Technical Requirements Manual,” (ADAMS Accession No. ML073620391).

ENCLOSURE 5

WBN Unit 2 Environmental Protection Plan (Non-Radiological)

APPENDIX B

TO FACILITY OPERATING LICENSE

ENVIRONMENTAL PROTECTION PLAN
(NON-RADIOLOGICAL)

FOR

WATTS BAR NUCLEAR PLANT, UNIT 2

DOCKET NO. 50-391

TENNESSEE VALLEY AUTHORITY

WATTS BAR NUCLEAR PLANT

UNIT 2

ENVIRONMENTAL PROTECTION PLAN (NON-RADIOLOGICAL)

TABLE OF CONTENTS

1.0 DEFINITIONS, ABBREVIATIONS, AND ACRONYMS

Annually	Annually is once per calendar year at intervals of twelve (12) calendar months ± 30 days
Clean Water Act	Federal Water Pollution Control Act (FWPCA) as amended.
FES	Final Environmental Statement (NUREG-0498) issued December 1978 by the NRC to the TVA (Control No. 7901100061).
FES Supplement 1	Final Environmental Statement (NUREG-0498 Supplement 1) issued April 1995 by the NRC to the TVA (ADAMS Accession No. ML081430592).
FES Supplement 2	Final Environmental Statement (NUREG-0498 Supplement 2, Vol. 1 & Vol. 2) issued May 2013 by the NRC to the TVA (ADAMS Accession Nos. ML13144A092 & ML13144A093).
FWS	U.S. Fish and Wildlife Service
NPDES Permit	NPDES permit is the National Pollutant Discharge Elimination System Permit No. TN0020168 issued by the U.S. Environmental Protection Agency to the Tennessee Valley Authority (TVA). This permit authorizes TVA to discharge controlled waste water, from the Watts Bar Plant Unit 2 into the Tennessee River.
NRC	U.S. Nuclear Regulatory Commission
Plant	Plant refers to the Watts Bar Nuclear Plant, either Unit 1 or Unit 2.
Site	Onsite includes any area within the property owned by the TVA specifically described in the WBN FES. Offsite includes all other areas.
Station	Station refers to Watts Bar Nuclear Plant Unit 1 and Unit 2.
TVA	Tennessee Valley Authority
Unit	Unit refers to Unit 1 or 2 (i.e., WBN Unit 1 or WBN Unit 2) of the Watts Bar Nuclear Plant, as defined by its usage.
WBN	Watts Bar Nuclear Plant

2.0 LIMITING CONDITIONS FOR OPERATION

None required

3.0 ENVIRONMENTAL MONITORING[1]

Environmental monitoring programs are conducted in accordance with the guidance and controls of agencies outside of the NRC. The NRC will relay on decisions made by the U.S. Environmental Protection Agency, U.S. Fish and Wildlife Service, and the State of Tennessee for any requirements on environmental monitoring. Therefore, no specific environmental monitoring is required by the NRC under this EPP.

3.1 Aquatic Monitoring

The certifications and permits required under the Clean Water Act provide mechanisms for protecting water quality and, indirectly, aquatic biota. The NRC will rely on the decision made by the U.S. Environmental Protection Agency and the State of Tennessee under the authority of the Clean Water Act for any requirements for aquatic monitoring.

3.2 Terrestrial Monitoring

Terrestrial monitoring is not required.

---

[1] In consideration of the provisions of the Clean Water Act (33 USC §1251, et seq.) and in the interest of avoiding duplication of effort, the conditions and monitoring requirements related to water quality and aquatic biota are specified in the National Pollution Discharge Elimination System (NPDES) Permit No. TN0020168 issued by the U.S. Environmental Protection Agency to the Tennessee Valley Authority (TVA). This permit authorizes TVA to discharge controlled waste water from the Watts Bar Nuclear Plant Unit 2 into the Tennessee River.

The Nuclear Regulatory Commission will be relying on the NPDES permit for protection of the aquatic environment from non-radiological effluents.

4.0 SPECIAL STUDIES AND REQUIREMENTS

4.1 Exceptional Occurrences

4.1.1 Unusual or Important Environmental Events

Requirements

Any occurrence of an unusual event or important event that indicates or could result in significant environmental impact causally related to plant operation shall be recorded and reported to the NRC within 24 hours followed by a written report in accordance with Subsection 5.4.2. If an event is reportable under 10 CFR 50.72, then a duplicate immediate report under this subsection is not required. However, a follow-up written report is required in accordance with Subsection 5.4.2.

The following are examples: excessive bird impact events, onsite plant or animal disease outbreaks, mortality of, or unusual occurrence involving any species protected by the Endangered Species Act of 1973 (ESA), the identification of any threatened or endangered species for which the NRC has not initiated consultation with the FWS, fish kills, increase in nuisance organisms or conditions in excess of levels anticipated in station environmental impact appraisals, and unanticipated or emergency discharge of waste water or any other chemical substance that exceeds the limits of, or is not authorized by, the NPDES permit and requires 24-hour notification to the State of Tennessee.

The licensee shall also notify the FWS Cookeville Field Office Field Supervisor or his designee when an unusual or important event results in the taking of, or could result in an adverse impact to, any species protected by the ESA. TVA should also notify the FWS law enforcement agent in Nashville, Tennessee if an unusual or important event involves the death, injury, or illness of any individual of a species protected by the ESA. Initial notification must be completed within 24 hours of the unusual or important event, followed by a written report per subsection 5.4.2.

No routine monitoring programs are required to implement this condition.

Action

Should an “Unusual or Important Environmental Event” occur, the licensee shall make a prompt report to the NRC in accordance with the provisions of Subsections 5.4.2.a and 5.4.2.c, or Subsection 5.4.2.d.

4.1.2 Exceeding Limits of Other Relevant Permits

Requirement

The licensee shall notify the NRC of occurrences in which the limits specified, in relevant permits and certificates issued by other Federal, State, and local governments are exceeded and which are reportable to those agencies. This requirement shall commence with the date of issuance of the operating license and continue for the life of the plant, unless changed in accordance with Subsection 5.5.1.

Action

The licensee shall make a report to the NRC in accordance with the provisions of Subsections 5.4.2.b and 5.4.2.c, or Subsection 5.4.2.d in the event of a reportable occurrence in which a limit specified in a relevant permit or certificate issued by another Federal, State, or local agency is exceeded.

4.2 Special Studies

None required at the present time.

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

The Plant Manager has responsibility for operating the plant in compliance with this Environmental Protection Plan.

5.2 Review and Audit

The licensee shall provide for review and audit of compliance with the Environmental Protection Plan. The audits shall be conducted independently of the Individual or groups responsible for performing the specific activity. A description of the organization structure utilized to achieve the independent review and audit function and results of the audit activities shall be maintained and made available for inspection.

5.2.1 Review

The licensee is responsible for the review of procedures for meeting the Environmental Protection Plan.

The above mentioned review shall be conducted on the following:

A. Proposed changes to the Environmental Protection Plan and evaluated impact of the change.

B. Proposed changes to station operating procedures, which affect the environmental effects of the station.

C. Proposed changes, construction, or modifications to station or unit equipment, or systems which might have an environmental impact, in order to determine the environmental impact of the change[2].

[2] Activities are excluded from this requirement if all measurable environmental effects are confined to on-site areas previously disturbed during site preparation and plant construction.

D. All routine reports prior to their submittals to NRC (described in Subsection 5.4.1).

E. All nonroutine reports prior to submittal of the written report (described in Subsections 5.4.a, b, and c).

F. Investigations of all reported instances of noncompliance with the Environmental Protection Plan, associated corrective actions, and measures taken to prevent recurrence.

5.2.2 Audit

The licensee shall conduct an audit on the environmental monitoring program. The audits shall be conducted independently of the individual or group responsible for performing the specific activity. Results of the audit activities shall be maintained and made available for inspection.

5.3 Changes in Station Design or Operation

Changes in station design or operation may be made subject to the following conditions:

A. The licensee may (1) make changes in the station design and operation, and (2) conduct tests and experiments not described in this document without prior Commission approval, unless the proposed change, test or experiment involves a change in the objectives of the Environmental Protection Plan[3] and/or an unreviewed environmental question of significant impact.

B. A proposed change, test or experiment shall be deemed to involve an unreviewed environmental question if it concerns (1) a matter which may result in a significant increase in any adverse environmental impact previously evaluated in the final environmental impact statement as modified by testimony to the Atomic Safety and Licensing Board, supplements thereto, environmental impact appraisals, or in initial or final adjudicatory decisions; or (2) a matter not previously reviewed and evaluated in the documents specified in (1) of this section which may have a significant adverse environmental impact.

C. The licensee shall maintain records of changes in facility design or operation made pursuant to this subsection. The licensee shall also maintain records of tests ad experiments carried out pursuant to paragraph “A” of this Subsection. These records shall include a written change, test, or experiment does not involve an unreviewed environmental question or substantive impact or constitute a change in the objectives of the Environmental Protection Plan. The licensee shall furnish to the Commission, annually or at such shorter intervals as may be specified in the license, a report containing description, analyses, interpretations, and evaluations of such changes, tests, and experiments.

[3] This provision does not relieve the licensee of the requirements of 10 CFR 50.59.

D. Changes in the special studies, if required in Section 4.2, which affects sampling frequency, location, gear, or replication shall be reported to the NRC within 30 days after their implementation, unless otherwise reported in accordance with Subsection 5.4.2. These reports shall describe the changes made, the reasons for making the changes, and an evaluation of the effectiveness of the revised program in assessing environmental impacts.

5.4 Station Reporting Requirements

5.4.1 Routine Reports

Annual Environmental Operation Report

A WBN dual-unit report on the environmental monitoring program for the previous year shall be submitted to the NRC separate from other NRC reporting requirements within 90 days following each anniversary of issuance of the WBN Unit 1 operating license. The WBN Unit 1 operating license anniversary date is utilized as the basis for the WBN dual-unit anniversary date, since it was the basis for the initial and subsequent reports. The report shall include summaries, analyses, interpretations, and statistical evaluation of the results of the environmental monitoring required by special studies and requirements (Section 4) for the report period, including a comparison with preoperational studies, operating controls (as appropriate), and previous non-radiological environmental monitoring reports, and an assessment of the observed impacts of the station operation on the environment. If harmful effects or evidence of irreversible damage are suggested by the monitoring programs, the licensee shall provide a more detailed analysis of the data and a proposed course of action to alleviate the problem.

For those programs concerned with water quality or protection of aquatic biota, which are regulated under the Clean Water Act, the requirements of this section shall be satisfied by submitting to the NRC copies of the reports as required by the NPDES permit (or otherwise required pursuant to the Clean Water Act), and in accordance with the frequency, content and schedules set forth by the agencies responsible for implementing the Clean Water Act.

In the event that some results are not available by the report date, the report shall be submitted noting and explaining the missing results. The missing data shall be submitted as soon as possible in a supplementary report.

The Annual Report shall also include a summary of:

1. All Environmental Protection Plan noncompliances and the corrective actions taken to remedy them.
2. Changes made to applicable State and Federal permits and certifications.
3. Changes to station design which could involve a significant environmental impact or change the findings of the FES.
4. All nonroutine reports submitted per Environmental Protection Plan Section 4.1.
5. Changes in the approved Environmental Protection Plan.

5.4.2 Nonroutine Reports

A report shall be submitted in the event that an "Unusual or Important Environmental Event," as specified in Subsection 4.1.1 occurs, or if another relevant permit is violated as specified in Subsection 4.1.2. The schedule and content for these nonroutine reports are described below.

5.4.2.a Prompt Report

Those events specified as requiring prompt reporting shall be reported within 24 hours by telephone, telegraph, or facsimile transmission to the NRC followed by a written report to the NRC within 30 days.

5.4.2.b Thirty Day Report

Those events not requiring a prompt report as described in Subsection 5.4.2.a shall be reported to the NRC within 30 days of their occurrence.

5.4.2.c Content of Nonroutine Reports

Written 30-day reports and, to the extent possible, the preliminary telephone, telegraph, or facsimile reports shall (a) describe, analyze, and evaluate the occurrence, including extent and magnitude of the impact, (b) describe the cause of the occurrence, (c) indicate the action taken to correct the reporting occurrence, and (d) indicate the corrective action taken (including any significant changes made in procedures) to preclude repetition of the occurrence and to prevent similar occurrences involving similar components or systems.

5.4.2.d Exceptions for Matters Regulated Under the Clean Water Act

For matters regulated under the Clean Water Act, the report schedules and content requirements described in Subsections 5.4.2.a, 5.4.2.b, and 5.4.2.c shall be satisfied by submitting, to the NRC copies of the reports as required by the NPDES permit (or other regulations pursuant to the Clean Water Act) and in accordance with the schedules and content requirements imposed thereby.

5.5 Changes in the Environmental Protection Plan and Permits

5.5.1 Changes in the Environmental Protection Plan

Requests for change to the Environmental Protection Plan shall be submitted to the NRC for review and authorization per 10 CFR 50.90. The request shall include an evaluation of the environmental impact of the proposed change and a supporting justification. Implementation of such requested changes to the Environmental Protection Plan shall not commence prior to incorporation by the NRC of the specifications in the license.

5.5.2 Changes in Permits and Certifications

Changes and additions to required Federal (other than NRC), State, local, and regional authority permits and certificates for the protection of the environment shall be reported to the NRC within 30 days. In the event that the licensee initiates or becomes aware of a request for changes to any of the water quality requirements, limits, or values stipulated in any certification or permit issued pursuant to the Clean Water Act, the NRC shall be notified within 30 days.

If a permit or certification, in part or in its entirety, is appealed and stayed, the NRC shall be notified within 30 days. If, as a result of the appeal process, the permit or certification requirements are changed, the change shall be dealt with as described in the previous paragraph of this section.

5.6 Records Retention

Records and logs relative to the environmental aspects of station operation shall be made and retained in a manner convenient for review and inspection. These records and logs shall be made available to NRC on request.

5.6.1 The following records shall be retained for the life of the station:

(a) Record of changes to the Environmental Protection Plan including, when applicable, records of NRC approval of such changes.

(b) Record of modifications to station structures, systems, and components determined to potentially affect the continued protection of the environment.

(c) Record of changes to permits and certifications required by Federal (other than the NRC), State, local, and regional authorities for the protection of the environment.

(d) Routine reports submitted to the NRC.

5.6.2 Records of the following shall be retained for a minimum of six (6) years:

(a) Review and audit activities.

(b) Events, and the reports thereon, which are the subjects of non-routine reports to the NRC.

5.6.3 Records associated with requirements of Federal (other than the NRC), State, local, and regional authorities' permits and certificates for the protection of the environment shall be retained for the period established by the respective permit or certificate.

ENCLOSURE 6

List of Commitments

1. The technical justification for the changes to WBN Unit 2 TS 3.2.1 and associated TS Bases will be provided to the NRC by September 30, 2015.