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10 CFR 50.4
10 CFR 50.71(e)
10 CFR 50.59

Serial: RA-21-0188
October 28, 2021

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

Catawba Nuclear Station, Units 1 and 2
Docket Nos. 50-413 and 50-414,
Renewed License Nos. NPF-35 and NPF-52

Subject: Submittal of Updated Final Safety Analysis Report (Revision 22), Technical Specification Bases Revisions, UFSAR/Selected Licensee Commitment Changes, and 10 CFR 50.59 Evaluation Summary Report

Ladies and Gentlemen:

Pursuant to 10 CFR 50.71(e), Duke Energy Carolinas, LLC (Duke Energy) hereby submits Revision 22 to the Updated Final Safety Analysis Report (UFSAR) for the Catawba Nuclear Station (CNS), Units 1 and 2. In accordance with 10 CFR 50.71(e)(4), this UFSAR revision is being submitted within six months following the most recent refueling outage, which concluded on May 3, 2021. Enclosure 1 provides a copy of the UFSAR that has been redacted for public use. Enclosure 2 provides a copy of the UFSAR that contains sensitive information to be withheld from public disclosure per 10 CFR 2.390(d)(1). Changes made since Revision 21 are identified by vertical lines in the margins of the pages that are indicated as Revision 22.

In accordance with 10 CFR 50.59(d)(2), Duke Energy is providing a report summarizing the 10 CFR 50.59 evaluations of changes, tests, and experiments implemented during the period from February 2, 2020 to July 17, 2021 for CNS. This report is included in Enclosure 3.

Pursuant to 10 CFR 50.4, Duke Energy is providing the CNS Technical Specification Bases changes that were made according to the provisions of Technical Specification 5.5.14, "Technical Specifications (TS) Bases Control Program." Enclosure 4 contains the TS Bases Insertion/Removal Instructions, the TS List of Effective Pages (LOEP) and Bases Replacement Pages.

Additionally, in accordance with 10 CFR 50.71(e), Duke Energy is providing the changes made to the CNS Selected Licensee Commitments (SLC) Manual since April 2, 2020. These changes are located in Enclosure 5. The CNS SLC manual constitutes Chapter 16 of the UFSAR.

There are no regulatory commitments contained in this letter.

If you have any questions regarding this submittal, please contact Lee Grzeck, Acting Fleet Licensing Manager, at (980) 373-1530.

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

Executed on October 28, 2021.

Sincerely,

Tom Simril

Tom Simril
Vice President, Catawba Nuclear Station

Enclosures:

1. Catawba Nuclear Station Updated Final Safety Analysis Report Update - Rev 22 Redacted Version (Publicly Available Information)
2. Catawba Nuclear Station Updated Final Safety Analysis Report Update - Rev 22 (Non-Publicly Available Information)
3. Catawba Nuclear Station 10 CFR 50.59 Evaluation Summary Report
4. Catawba Nuclear Station Technical Specification (TS) Bases Changes
5. Catawba Nuclear Station Selected Licensee Commitments (SLC) Manual Changes

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U.S. Nuclear Regulatory Commission
RA-21-0188
October 28, 2021

Enclosure 1

Catawba Nuclear Station
Updated Final Safety Analysis Report Update - Rev 22 Redacted Version
(Publicly Available Information)

Enclosure 2

Catawba Nuclear Station
Updated Final Safety Analysis Report Update - Rev 22
(Non-Publicly Available Information)

Enclosure 3

Catawba Nuclear Station
10 CFR 50.59 Evaluation Summary Report

Summary of 10 CFR 50.59 Evaluations

Title:
Allison Creek Black Relay Project

Documentation Number(s):
Action Request (AR) 02327170

Brief Description:

Engineering Change 414903 in conjunction with Transmission Modification FF4930C3 upgrades the protective relaying for the Allison Creek Black 230 kV transmission line which terminates at one end in the Catawba 230 kV switchyard.

This upgrade involves replacement of analog equipment that performs protection, communication and metering functions with microprocessor-based (i.e. digital) equipment. The specific activities related to this modification include:

1. Replacement of the analog protective relays for the primary and secondary line protection with SEL-421 digital relays.
2. Replace the existing Westinghouse KC-4 analog breaker failure relay and associated analog breaker failure timer for PCB 13 (Allison Black 230 kV line) with a SEL-351 digital relay.
3. Upgrade of communication equipment to support the new digital relaying scheme.
4. Changes to Miscellaneous Electro-Mechanical Relay Accessory and Test Devices.

From this evaluation it is concluded that the change can be implemented under 10CFR 50.59 without prior approval from the NRC.

Summary of 10 CFR 50.59 Evaluations

Title:
Addition of Tornado Missile Risk Evaluator (TMRE) to license

Documentation Number(s):
Action Request (AR) 02334414

Brief Description:

Adopt a new methodology, Tornado Missile Risk Evaluator (TMRE), which has been developed specifically to address existing nonconforming SSCs associated with the Tornado Missile Protection (TMP) licensing basis. Tornado Missile Risk Evaluator (TMRE), NEI 17-02 Rev 1B, is an alternate methodology for determining whether protection from tornado-generated missiles is required.

The TMRE will be used to evaluate and qualify non-conformities associated with TMP at CNS. Specifically, the TMRE methodology is being used to address the non-conformances associated with tornado missile targets within line of sight openings in the main steam doghouses.

The adoption of the TMRE methodology will be documented in UFSAR sections 3.5.1.4 and added to references in UFSAR section 3.5.4. UFSAR section 3.5.2 will be revised to document the evaluation of the TMP non conformances associated with components within the doghouses that are exposed through the gull wing openings near the top of the doghouse structures. UFSAR Table 3-1 will be revised to add note indicating that TMRE was used to evaluate nonconformance with tornado protection. The PRA analysis in reference 5 documents the TMRE evaluation of the doghouse components.

From this evaluation it is concluded that the change can be implemented under 10CFR 50.59 without prior approval from the NRC.

Summary of 10 CFR 50.59 Evaluations

Title:
Update UFSAR Section 6.6.8 with NRC-approved methodology

Documentation Number(s):
Action Request (AR) 02352233

Brief Description:

Section 6.6.8 of the Catawba Nuclear Station (CNS) Updated Final Safety Analysis Report (UFSAR) is being revised to address the adoption of the Nuclear Regulatory Commission (NRC-) approved alternative methodology for defining the number of augmented piping inspections on the Break Exclusion Region (BER) for Units 1 & 2. This Section of the UFSAR discusses augmented inservice inspections to be performed in support of protecting against postulated piping failures in the BER. CNS is adopting a risk-informed evaluation process for BER piping in accordance with EPRI Topical Report TR-1006937, "Extension of the EPRI Risk-Informed Inservice Inspection (RI-ISI) Methodology to Break Exclusion Region (BER) Programs," Rev. 0-A (Reference 5). As documented in the NRC Safety Evaluation (SE) dated June 27, 2002 (Reference 6), EPRI Topical Report TR-1006937 was found to be acceptable for referencing in licensing applications and that licensees may implement changes to their BER programs according to the provisions of 10 CFR 50.59, with prior NRC approval not required if the change involves the use of a method previously approved by the NRC. The changes to the BER program identified in CNS UFSAR Section 6.6.8 invoke the NRC-approved methodology from the SE (Reference 6) and revises the method for determining the inspection locations and number of welds to be examined for BER piping. Implementation of this risk -informed methodology for BER piping at CNS will reduce the total augmented inservice inspection requirement from 100% to 10% per unit.

From this evaluation it is concluded that the change can be implemented under 10CFR 50.59 without prior approval from the NRC.

Enclosure 4

Catawba Nuclear Station
Technical Specification (TS) Bases Changes

Removal and insertion instructions for Catawba Nuclear Station Technical Specification Bases Changes for February 2, 2020 thru September 28, 2021.

<u>REMOVE THESE PAGES</u>	**<u>INSERT THESE PAGES</u>**

LIST OF EFFECTIVE PAGES

Pages 1-19 Revision 27 (11/11/19)	Pages 1-19 Revision 36 (9/28/21)

**TECHNICAL SPECIFICATIONS
BASES**

TAB B 3.4

B 3.4.7-1 thru 7 Revision 7	B 3.4.7-1 thru 8 Revision 8
B 3.4.8-1 thru 4 Revision 4	B 3.4.8-1 thru 5 Revision 5

TAB B 3.6

B 3.6.17-1 Revision 2	B 3.6.17-1 Revision 4
B 3.6.17-2 Revision 1	B 3.6.17-2 Revision 4
B 3.6.17-3 Revision 0	B 3.6.17-3 Revision 4
B 3.6.17-4 Revision 0	B 3.6.17-4 Revision 4
B 3.6.17-5 Revision 1	B 3.6.17-5 Revision 4

TAB B 3.7

B 3.7.8-1 thru 11 Revision 8	B 3.7.8-1 thru 12 Revision 10
B 3.7.10-1 thru 9 Revision 13	B 3.7.10-1 thru 9 Revision 14
B 3.7.11-1 thru 4 Revision 4	B 3.7.11-1 thru 4 Revision 5

B 3.7.12-1 thru 7 Revision 10	B 3.7.12-1 thru 7 Revision 11

TAB B 3.8

B 3.8.1-1 thru 39 Revision 7	B 3.8.1-1 thru 39 Revision 8

TAB B 3.9

B 3.9.5-1 thru 5 Revision 6	B 3.9.5-1 thru 5 Revision 7

Catawba Nuclear Station Technical Specifications

List of Effective Pages

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ii	219/214	3/01/05
iii	215/209	6/21/04
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1.1-3	299/295	10/23/18
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1.1-5	281/277	4/29/16
1.1-6	268/264	6/25/12
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1.2-1	173/165	9/30/98
1.2-2	173/165	9/30/98
1.2-3	173/165	9/30/98
1.3-1	298/294	2/1/18
1.3-2	298/294	2/1/18
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1.3-14	298/294	2/1/18
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1.4-2	173/165	9/30/98

1.4-3	173/165	9/30/98
1.4-4	173/165	9/30/98
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3.0-1	288/284	4/26/17
3.0-2	298/294	2/1/18
3.0-3	235/231	3/19/07
3.0-4	288/284	4/26/17
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3.1.4-4	263/259	3/29/11
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3.1.5-2	263/259	3/29/11
3.1.6-1	173/165	9/30/98
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3.1.6-3	263/259	3/29/11
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3.3.1-17	263/259	3/29/11
3.3.1-18	263/259	3/29/11
3.3.1-19	278/274	4/08/16
3.3.1-20	263/259	3/29/11
3.3.1-21	263/259	3/29/11
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3.3.2-1	173/165	9/30/98
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3.3.2-7	249/243	4/2/09
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3.3.5-1	173/165	9/30/98
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3.3.6-2	263/259	3/29/11
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3.4.1-6 (deleted)	184/176	3/01/00
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3.4.3-1	173/165	9/30/98
3.4.3-2	263/259	3/29/11
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3.4.6-3	282/278	4/26/17
3.4.7-1	212/206	3/4/04
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3.4.7-3	282/278	4/26/17
3.4.8-1	207/201	7/29/03
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3.4.9-1	173/165	9/30/98
3.4.9-2	263/259	3/29/11
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3.4.10-2	299/295	10/23/18
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3.5.4-1	173/165	9/30/98
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3.6.2-1	173/165	9/30/98
3.6.2-2	173/165	9/30/98
3.6.2-3	173/165	9/30/98
3.6.2-4	173/165	9/30/98
3.6.2-5	263/259	3/29/11
3.6.3-1	173/165	9/30/98
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3.6.4-1	263/259	3/29/11
3.6.5-1	173/165	9/30/98
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3.6.8-2	263/259	3/29/11
3.6.9-1	253/248	10/30/09
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3.6.14-1	173/165	9/30/98
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3.6.16-2	263/259	3/29/11
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3.7.8-3	271/267	08/09/13
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3.7.8-5 (new)	300/296	11/28/18
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3.7.16-2	233/229	9/27/06
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3.8.1-3	304/300	11/11/19
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3.8.1-5 (new)	304/300	11/11/19
3.8.1-6 (new)	304/300	11/11/19
3.8.1-7 (new)	304/300	11/11/19
3.8.1-8 (new)	304/300	11/11/19
3.8.1-9 (new)	304/300	11/11/19
3.8.1-10 (new)	304/300	11/11/19
3.8.1-11	308/304	9/28/21
3.8.1-12	263/259	3/29/11
3.8.1-13	308/304	9/28/21
3.8.1-14	308/304	9/28/21
3.8.1-15	308/304	9/28/21
3.8.1-16	308/304	9/28/21
3.8.1-17	263/259	3/29/11
3.8.1-18	308/304	9/28/21
3.8.1-19	292/288	9/08/17
3.8.1-20	308/304	9/28/21
3.8.1-21	308/304	9/28/21
3.8.2-1	173/165	9/30/98
3.8.2-2	207/201	7/29/03
3.8.2-3	173/165	9/30/98

3.8.3-1	175/167	1/15/99
3.8.3-2	263/259	3/29/11
3.8.3-3	263/259	3/29/11
3.8.4-1	173/165	9/30/98
3.8.4-2	263/259	3/29/11
3.8.4-3	292/288	9/08/17
3.8.4-4	292/288	9/08/17
3.8.4-5	262/258	12/20/10
3.8.5-1	173/165	9/30/98
3.8.5-2	207/201	7/29/03
3.8.6-1	253/248	10/30/09
3.8.6-2	253/248	10/30/09
3.8.6-3	253/248	10/30/09
3.8.6-4	263/259	3/29/11
3.8.6-5	223/218	4/27/05
3.8.7-1	173/165	9/30/98
3.8.7-2	263/259	3/29/11
3.8.8-1	173/165	9/30/98
3.8.8-2	263/259	3/29/11
3.8.9-1	173/165	9/30/98
3.8.9-2	173/165	9/30/98
3.8.9-3	263/259	3/29/11
3.8.10-1	207/201	7/29/03
3.8.10-2	263/259	3/29/11
3.9.1-1	263/259	3/29/11
3.9.2-1	215/209	6/21/04
3.9.2-2	263/259	3/29/11
3.9.3-1	227/222	9/30/05
3.9.3-2	301/297	4/18/19
3.9.4-1	207/201	7/29/03
3.9.4-2	297/293	1/4/18
3.9.5-1	293/289	9/29/17
3.9.5-2	297/293	1/4/18
3.9.6-1	263/259	3/29/11

3.9.7-1	263/259	3/29/11
4.0-1	284/280	6/21/16
4.0-2	233/229	9/27/06
5.1-1	273/269	2/12/15
5.2-1	273/269	2/12/15
5.2-2	273/269	2/12/15
5.2-3	Deleted	9/21/09
5.3-1	307/303	11/17/20
5.4-1	173/165	9/30/98
5.5-1	286/282	9/12/16
5.5-2	286/282	9/12/16
5.5-3	173/165	9/30/98
5.5-4	173/165	9/30/98
5.5-5	216/210	8/5/04
5.5-6	299/295	10/23/18
5.5-7	280/276	4/26/16
5.5-8	280/276	4/26/16
5.5-9	280/276	4/26/16
5.5-10	280/276	4/26/16
5.5-11	280/276	4/26/16
5.5-12	280/276	4/26/16
5.5-13	280/276	4/26/16
5.5-14	301/297	4/18/19
5.5-15	280/276	4/26/16
5.5-16	280/276	4/26/16
5.5-17	280/276	4/26/16
5.5-18	280/276	4/26/16
5.5-19	280/276	4/26/16
5.6-1	222/217	3/31/05
5.6-2	253/248	10/30/09
5.6-3	222/217	3/31/05
5.6-4	284/280	6/21/16
5.6-5	301/297	4/18/19
5.6-6	280/276	4/26/16

5.7-1	273/269	2/12/15
5.7-2	173/165	9/30/98

BASES

i	Revision 1	4/08/99
ii	Revision 2	3/01/05
iii	Revision 1	6/21/04
B 2.1.1-1	Revision 0	9/30/98
B 2.1.1-2	Revision 1	12/19/03
B 2.1.1-3	Revision 1	12/19/03
B 2.1.2-1	Revision 0	9/30/98
B 2.1.2-2	Revision 0	9/30/98
B 2.1.2-3	Revision 0	9/30/98
B 3.0-1 thru B 3.0-21	Revision 7	5/02/19
B 3.1.1-1 thru B 3.1.1-6	Revision 3	5/05/11
B 3.1.2-1 thru B 3.1.2-5	Revision 3	11/14/17
B 3.1.3-1 thru B 3.1.3-6	Revision 2	4/14/15
B 3.1.4-1 thru B 3.1.4-9	Revision 1	5/05/11
B 3.1.5-1 thru B 3.1.5-4	Revision 2	5/05/11
B 3.1.6-1 thru B 3.1.6-6	Revision 1	5/05/11
B 3.1.7-1	Revision 0	9/30/98
B 3.1.7-2	Revision 2	1/08/04
B 3.1.7-3	Revision 2	1/08/04
B 3.1.7-4	Revision 2	1/08/04
B 3.1.7-5	Revision 2	1/08/04
B 3.1.7-6	Revision 2	1/08/04
B 3.1.8-1 thru B 3.1.8-6	Revision 4	3/28/18
B 3.2.1-1 thru B 3.2.1.-11	Revision 4	5/05/11

B 3.2.2-1 thru B 3.2.2-10	Revision 3	5/05/11
B 3.2.3-1 thru B 3.2.3-4	Revision 2	5/05/11
B 3.2.4-1 thru B 3.2.4-7	Revision 2	5/05/11
B 3.3.1-1 thru B.3.3.1-55	Revision 8	4/08/16
B 3.3.2-1 thru B 3.3.2-50	Revision 12	12/18/15
B 3.3.3-1 thru B.3.3.3-16	Revision 6	4/11/14
B 3.3.4-1 thru B 3.3.4-5	Revision 2	5/05/11
B 3.3.5-1 thru B 3.3.5-6	Revision 3	12/18/15
B 3.3.6-1 thru B 3.3.6-5	Revision 6	08/02/12
B 3.3.9-1 thru B 3.3.9-5	Revision 3	06/02/14
B 3.4.1-1 thru B 3.4.1-5	Revision 3	5/05/11
B 3.4.2-1	Revision 0	9/30/98
B 3.4.2-2	Revision 0	9/30/98
B 3.4.2-3	Revision 0	9/30/98
B 3.4.3-1 thru B 3.4.3-6	Revision 2	5/05/11
B 3.4.4-1 thru B 3.4.4-3	Revision 2	5/05/11
B 3.4.5-1 thru B 3.4.5-6	Revision 3	5/05/11
B 3.4.6-1 thru B 3.4.6-6	Revision 5	4/26/17

B 3.4.7-1 thru B 3.4.7-8	Revision 8	5/20/20
B 3.4.8-1 thru B 3.4.8-5	Revision 5	5/20/20
B 3.4.9-1 thru B 3.4.9-5	Revision 3	08/02/12
B 3.4.10-1 thru B 3.4.10-4	Revision 4	10/23/18
B 3.4.11-1 thru B 3.4.11-7	Revision 4	5/05/11
B 3.4.12-1 thru B 3.4.12-13	Revision 6	10/23/18
B 3.4.13-1 thru B 3.4.13-7	Revision 7	3/15/12
B 3.4.14-1 thru B 3.4.14-6	Revision 3	5/05/11
B 3.4.15-1 thru B 3.4.15-10	Revision 6	5/05/11
B 3.4.16-1 thru B 3.4.16-5	Revision 4	10/23/12
B 3.4.17-1 thru B 3.4.17-3	Revision 2	5/05/11
B 3.4.18-1 thru B 3.4.18-8	Revision 2	4/26/16
B 3.5.1-1 thru B 3.5.1-8	Revision 4	4/26/17
B 3.5.2-1 thru B 3.5.2-11	Revision 5	10/23/18
B 3.5.3-1 thru B 3.5.3-3	Revision 2	4/26/17
B 3.5.4-1 thru B.3.5.4-5	Revision 5	4/11/14
B 3.5.5-1 thru B 3.5.5-4	Revision 1	5/05/11

B 3.6.1-1	Revision 1	7/31/01
B 3.6.1-2	Revision 1	7/31/01
B 3.6.1-3	Revision 1	7/31/01
B 3.6.1-4	Revision 1	7/31/01
B 3.6.1-5	Revision 1	7/31/01
B 3.6.2-1 thru B 3.6.2-8	Revision 2	5/05/11
B 3.6.3-1 thru B 3.6.3-14	Revision 7	10/23/18
B 3.6.4-1 thru B 3.6.4-4	Revision 2	5/05/11
B 3.6.5-1 thru B 3.6.5-4	Revision 3	07/27/13
B 3.6.6-1 thru B 3.6.6-8	Revision 8	10/23/18
B 3.6.8-1 thru B 3.6.8-5	Revision 3	5/05/11
B 3.6.9-1 thru B 3.6.9-5	Revision 6	5/05/11
B 3.6.10-1 thru B 3.6.10-6	Revision 4	7/15/19
B 3.6.11-1 thru B 3.6.11-6	Revision 5	5/05/11
B 3.6.12-1 thru B 3.6.12-11	Revision 5	5/05/11
B 3.6.13-1 thru B 3.6.13-9	Revision 4	5/05/11
B 3.6.14-1 thru B 3.6.14-5	Revision 2	4/11/14
B 3.6.15-1 thru B 3.6.15-4	Revision 1	5/05/11
B 3.6.16-1 thru B 3.6.16-4	Revision 3	5/05/11

B 3.6.17-1 thru B 3.6.17-5	Revision 4	7/07/20
B 3.7.1-1 thru 3.7.1-5	Revision 3	10/23/18
B 3.7.2-1 thru B 3.7.2-5	Revision 4	10/23/18
B 3.7.3-1 B 3.7.3-6	Revision 3	10/23/18
B 3.7.4-1 thru B 3.7.4-4	Revision 3	11/14/17
B 3.7.5-1 thru B 3.7.5-9	Revision 5	10/23/18
B 3.7.6-1 thru B 3.7.6-3	Revision 6	9/10/18
B 3.7.7-1 thru B 3.7.7-5	Revision 2	5/05/11
B 3.7.8-1 thru B 3.7.8-12	Revision 10	5/21/20
B 3.7.9-1 thru B 3.7.9-4	Revision 3	5/05/11
B 3.7.10-1 thru B 3.7.10-9	Revision 14	4/23/20
B 3.7.11-1 thru B 3.7.11-4	Revision 5	4/23/20
B 3.7.12-1 thru B 3.7.12-7	Revision 11	4/23/20
B 3.7.13-1 thru B 3.7.13-5	Revision 6	7/15/19
B 3.7.14-1 thru B 3.7.14-3	Revision 2	5/05/11
B 3.7.15-1 thru B 3.7.15-4	Revision 2	5/05/11
B 3.7.16-1	Revision 2	9/27/06
B 3.7.16-2	Revision 2	9/27/06

B 3.7.16-3	Revision 2	9/27/06
B 3.7.16-4	Revision 0	9/27/06
B 3.7.17-1 thru B 3.7.17-3	Revision 2	5/05/11
B 3.8.1-1 thru B.3.8.1-39	Revision 8	9/28/21
B 3.8.2-1	Revision 0	9/30/98
B 3.8.2-2	Revision 0	9/30/98
B 3.8.2-3	Revision 0	9/30/98
B 3.8.2-4	Revision 3	11/11/19
B 3.8.2-5	Revision 2	5/10/05
B 3.8.2-6	Revision 1	5/10/05
B 3.8.3-1 thru B 3.8.3-8	Revision 4	5/05/11
B 3.8.4-1 thru B3.8.4.11	Revision 11	10/30/17
B 3.8.5-1	Revision 0	9/30/98
B 3.8.5-2	Revision 2	7/29/03
B 3.8.5-3	Revision 1	7/29/03
B 3.8.6-1 thru B 3.8.6-7	Revision 4	5/05/11
B 3.8.7-1 thru B 3.8.7-4	Revision 3	5/05/11
B 3.8.8-1 thru B 3.8.8-4	Revision 3	5/05/11
B 3.8.9-1 thru B 3.8.9-10	Revision 2	5/05/11
B 3.8.10-1 thru B 3.8.10-4	Revision 3	5/05/11
B 3.9.1-1 thru B 3.9.1-4	Revision 3	5/05/11
B 3.9.2-1 thru B 3.9.2-3	Revision 6	3/21/17

B 3.9.3-1 thru B 3.9.3-5	Revision 5	7/15/19
B 3.9.4-1 thru B 3.9.4-6	Revision 6	1/23/18
B 3.9.5-1 thru B 3.9.5-5	Revision 7	5/21/20
B 3.9.6-1 thru B 3.9.6-3	Revision 2	5/05/11
B 3.9.7-1 thru B 3.9.7-3	Revision 1 .	5/05/11

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 transfer this heat either to 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 narrow range water levels ≥ 12% to provide an alternate method for decay 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.
RCS Loops—MODE 5 (Loops Filled) satisfy Criterion 4 of 10 CFR 50.36 Ref. 1).

BASES

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 narrow range water level ≥ 12%. 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 narrow range water levels ≥ 12%. Should the operating RHR loop fail, the SGs could be used to remove the decay heat. NRC Information Notices 94-36 and 95-35 and Westinghouse Nuclear Safety Advisory Letter 94-13 address concerns with crediting of natural circulation alternate cooling as backup to the loss of an RHR pump. Specifically, when the RCS is depressurized, there is potential for gas accumulation in the high points in the SG tubes and steam voiding in the SG tubes if the RCS pressure boundary is not intact such that the RCS can pressurize to maintain the reactor coolant subcooled to prevent steam void formation. Gas or steam void formation in the RCS loops could impede natural circulation. The B and C RCS loops are not credited as an acceptable alternate method of heat removal when all four reactor coolant pumps (RCPs) are off due to the potential for gas accumulation at the top of the SG tubes. RHR flow results in higher flow of gas-saturated water to the hot legs associated with the RHR suction drop. Therefore, gas accumulation at the high points of RCS loops supplying suction to the RHR pumps is more likely to result in gas accumulation that could impede natural circulation.

“Loops Filled” is defined as follows in operating procedures:

> For RCS loops to be considered filled, the RCS pressure boundary must be intact or able to be quickly restored by control room action. The RCS must be capable of pressurizing to the Low Temperature Overpressure Protection (LTOP) setpoint of 400 psig. If the current outage requires a fill and vent of the RCS, a fill and vent has been procedurally completed. The RCS must also meet level conditions that ensure sufficient pressure at the top of the SG tubes to prevent steam void formation when the pressurizer is vented to atmosphere.

Note 1 permits all RHR pumps to be de-energized ≤ 1 hour per 8 hour period. The purpose of the Note is to permit tests designed to validate various accident analyses values. One of the tests performed during the startup testing program is the validation of rod drop times during cold conditions, both with and without flow. The no flow test may be performed in MODE 3, 4, or 5 and requires that the pumps be stopped for a short period of time. The Note permits de-energizing of the pumps in order to perform this test and validate the assumed analysis values. If changes are

LCO (continued)

made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again.

The 1 hour time period is adequate to perform the test, and operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 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 with coolant with boron concentrations less than required to meet SDM of LCO 3.1.1, therefore maintaining an adequate margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure SDM is maintained 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.

Note 2 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 3 requires that the secondary side water temperature of each SG be ≤ 50°F above each of the RCS cold leg temperatures before the start of an RCP with an RCS cold leg temperature ≤ 210°F. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 4 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.

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. If not in its normal RHR alignment from the RCS hot leg and returning to the RCS cold legs, the required RHR loop is OPERABLE provided the system may be placed in service from the control room, or may be placed in

BASES

LCO (continued)

service in a short period of time by actions outside the control room and there are no restraints to placing the equipment in service. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An OPERABLE RHR heat exchanger includes an available heat sink comprised of the necessary component cooling support function to meet RHR heat load requirements. Component cooling support for RHR may be provided by a cross connected alignment where opposite train component cooling pumps can be aligned through a single component cooling heat exchanger. SGs A or D can perform as OPERABLE heat sinks with adequate water level; SGs B or C can perform as OPERABLE heat sinks with adequate water level and at least one RCP in operation.

Management of gas voids is important to RHR System OPERABILITY.

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 narrow range water level of at least two SGs is required to be ≥ 12%.

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 3.4.17 "RCS Loops—Test Exceptions";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.5, "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 narrow range water levels < 12%, 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.

BASES

ACTIONS (continued)

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 introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1 must be suspended and action to restore one RHR loop to OPERABLE status and operation must be initiated. RCP seal injection flow is not considered to be an operation involving a reduction in RCS boron concentration. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however, coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to criticality. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification 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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.2

Verifying that at least two SGs are OPERABLE by ensuring their secondary side narrow range water levels are ≥ 12% ensures an alternate decay heat removal method in the event that the second RHR loop is not OPERABLE. The A and D SGs are OPERABLE with ≥ 12% narrow range level. The B and C SGs are OPERABLE if narrow range levels are ≥ 12% and at least one RCP is in operation. If both RHR loops are OPERABLE, this Surveillance is not needed. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an

SURVEILLANCE REQUIREMENTS (continued)

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 narrow range water level is $\geq$ 12% in at least two SGs, this Surveillance is not needed. The A and D SGs are OPERABLE with $\geq$ 12% narrow range level. The B and C SGs are OPERABLE if narrow range levels are $\geq$ 12% and at least one RCP is in operation. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.4

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the required RHR loop(s) and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are

BASES

SURVEILLANCE REQUIREMENTS (continued)

subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).
2. Problem Investigation Process M-00-02276.

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 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) satisfy Criterion 4 of 10 CFR 50.36 (Ref. 1).

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.

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 at least 10°F below saturation temperature. The Note prohibits boron dilution with coolant at boron concentrations less than required to assure SDM of LCO 3.1.1 is maintained or draining operations when RHR forced flow is stopped.

BASES

LCO (continued)

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. If not in its normal RHR alignment from the RCS hot leg and returning to the RCS cold legs, the required RHR loop is OPERABLE provided the system may be placed in service from the control room, or may be placed in service in a short period of time by actions outside the control room and there are no restraints to placing the equipment in service. Management of gas voids is important to RHR System OPERABILITY.

An operable RHR heat exchanger includes an available heat sink comprised of the necessary component cooling support function to meet RHR heat load requirements. Component cooling support for RHR may be provided by a cross connected alignment where opposite train component cooling pumps can be aligned through a single component cooling heat exchanger.

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 3.4.17, "RCS Loops—Test Exceptions";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level" (MODE 6).

ACTIONS

A.1

If only one RHR loop is OPERABLE and in operation, redundancy for RHR

BASES

ACTIONS (continued)

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 introduction of coolant into the RCS with boron concentration less than required to meet SDM of LCO 3.1.1 must be suspended and action must be initiated immediately to restore an RHR loop to OPERABLE status and operation.

RCP seal injection flow is not considered to be an operation involving a reduction in RCS boron concentration. The required margin to criticality must not be reduced in this type of operation. Suspending the introduction of coolant into the RCS of coolant with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 is required to assure continued safe operation. With coolant added without forced circulation, unmixed coolant could be introduced to the core, however, coolant added with boron concentration meeting the minimum SDM maintains acceptable margin to criticality. 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 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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.8.2

Verification that the required number of pumps are 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 required pumps. The Surveillance Frequency is based on operating

SURVEILLANCE REQUIREMENTS (continued)

experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.4.8.3

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR loops and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and

BASES

determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).

B 3.6 CONTAINMENT SYSTEMS

B 3.6.17 Containment Valve Injection Water System (CVIWS)

BASES

BACKGROUND

The CVIWS is required by 10 CFR 50, Appendix A, GDC 54, "Piping Systems Penetrating Containment" (Ref. 1), to ensure a water seal to a specific class of containment isolation valves (double disc gate valves) during a LOCA, to prevent leakage of containment atmosphere through the gate valves.

The CVIWS is designed to inject water between the two seating surfaces of double disc gate valves used for Containment isolation. The injection pressure is higher than Containment design peak pressure during a LOCA. This will prevent leakage of the Containment atmosphere through the gate valves, thereby reducing potential offsite dose below the values specified by 10 CFR 50.67 limits following the postulated accident.

During normal power operation, the system is in a standby mode and does not perform any function. During accident situations the CVIWS is activated to perform its safety related function, thus limiting the release of containment atmosphere past specific containment isolation valves, in order to mitigate the consequences of a LOCA. Containment isolation valves, for systems which are not used to mitigate the consequences of an accident, will be supplied with CVIWS seal water upon receipt of a Phase A isolation signal.

The system consists of two independent, redundant trains; one supplying gate valves that are powered by the A train diesel and the other supplying gate valves powered by the B train diesel. This separation of trains prevents the possibility of both containment isolation valves not sealing due to a single failure.

Each train consists of a surge chamber which is filled with water and pressurized with nitrogen. One main header exits the chamber and splits into several headers. An air operated valve, located in the main header before any of the branch headers, will open after a 60 second delay on a Phase A isolation signal. Each of the branch headers supply injection water to containment isolation valves located in the same general location, and close on the same engineered safety signal. The delay for the opening of the air operated valves is to allow adequate time for the slowest gate valve to close, before water is injected into the valve seat.

BACKGROUND (continued)

Makeup water is provided from the Demineralized Water Storage Tank for testing and adding water to the surge chamber during normal plant operation. Assured water is provided from the essential header of the Nuclear Service Water System (NSWS). This supply is assured for at least 30 days following a postulated accident. If the water level in the surge chamber drops below the low-low level or if the surge chamber nitrogen pressure drops below the low-low pressure after a Phase A isolation signal, an air operated valve in the supply line from the NSWS will automatically open and remains open, assuring makeup to the CVIWS at a pressure greater than 110% of peak Containment accident pressure.

Overpressure protection is provided to relieve the pressure buildup caused by the heatup of a trapped volume of incompressible fluid between two positively closing valves (due to containment temperature transient) back into containment where an open relief path exists.

APPLICABLE SAFETY ANALYSES

The CVIWS design basis is established by the consequences of the limiting DBA, which is a LOCA. The accident analysis (Ref. 2) assumes that only one train of the CVIWS is functional due to a single failure that disables the other train. Makeup water can be assured from the NSWS for 30 days following a postulated LOCA.

The CVIWS satisfies Criterion 3 of 10 CFR 50.36 (Ref. 3).

LCO

In the event of a DBA, one CVIWS train is required to provide the seal injection assumed in the safety analysis. Two trains of the CVIWS must be OPERABLE to ensure that at least one train will operate, assuming that the other train is disabled by a single active failure.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could require a containment isolation. 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 CVIWS is not required to be OPERABLE.

ACTIONS

A.1

With one CVIWS 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 valve injection needs after a DBA. The 7 day Completion Time is based on consideration of such factors as the availability of the OPERABLE redundant CVIWS 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 CVIWS 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 3.6.17.1

Verifying each CVIWS train is pressurized to ≥ 36.4 psig ensures the system can meet the design basis. Assured water is provided from the essential header of the NSWS. The 31 day Frequency was developed in consideration of the known reliability of the system and the two train redundancy available.

SR 3.6.17.2

This SR verifies that each CVIWS train can perform its required function when needed by measuring the existing conditions for the valves being injected. Gate valves served by the CVIWS do not receive a conventional Type C leak rate test using air as a test medium.

The containment isolation valves served by the CVIWS may be tested individually or simultaneously. Containment isolation valves are leak rate tested by this SR by injecting seal water from the CVIWS to the containment isolation valves. With the containment isolation valve closed, the leakage is determined by measuring flow rate of seal water out of the containment valve injection water surge chamber.

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 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 CVIWS OPERABILITY is demonstrated at a 31 day Frequency by SR 3.6.17.1.

SR 3.6.17.3

This SR ensures that each CVIWS train responds properly to the appropriate actuation signal. The Surveillance verifies that the automatic valves actuate to their correct position. 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 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.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 54.
2. UFSAR, Section 6.2.
3. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).
4. 10 CFR 50.67.

B 3.7 PLANT SYSTEMS

B 3.7.8 Nuclear Service Water System (NSWS)

BASES

BACKGROUND

The NSWS, including Lake Wylie and the Standby Nuclear Service Water Pond (SNSWP), 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 NSWS also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The NSWS consists of two independent loops (A and B) of essential equipment, each of which is shared between units. Each loop contains two NSWS pumps, each of which is supplied from a separate emergency diesel generator. Each set of two pumps supplies two trains (1A and 2A, or 1B and 2B) of essential equipment through common discharge piping. While the pumps are unit designated, i.e., 1A, 1B, 2A, 2B, all pumps receive automatic start signals from a safety injection or blackout signal from either unit. Therefore, a pump designated to one unit will supply post accident cooling to equipment in that loop on both units, provided its associated emergency diesel generator is available. For example, the 1A NSWS pump, supplied by emergency diesel 1A, will supply post accident cooling to NSWS trains 1A and 2A.

One NSWS loop containing two OPERABLE NSWS pumps has sufficient capacity to supply post loss of coolant accident (LOCA) loads on one unit and shutdown and cooldown loads on the other unit. Thus, the OPERABILITY of two NSWS loops assures that no single failure will keep the system from performing the required safety function. Furthermore, one OPERABLE NSWS pump on each NSWS loop has sufficient capacity to supply post LOCA loads on one unit and shutdown and cooldown loads on the other unit. Additionally, one NSWS loop containing one OPERABLE NSWS pump has sufficient capacity to maintain one unit indefinitely in MODE 5 (commencing 36 hours following a trip from RTP) while supplying the post LOCA loads of the other unit. Thus, after a unit has been placed in MODE 5, only one NSWS pump and its associated emergency diesel generator are required to be OPERABLE on each loop, in order for the system to be capable of performing its required safety function, including single failure considerations.

BASES

BACKGROUND (continued)

Additional information about the design and operation of the NSWS, along with a list of the components served, is presented in the UFSAR, Section 9.2.1 (Ref. 1). The principal safety related function of the NSWS is the removal of decay heat from the reactor via the CCW System.

APPLICABLE SAFETY ANALYSES

The design basis of the NSWS is for one NSWS train, in conjunction with the CCW System and a containment spray system, to remove core decay heat following a design basis LOCA as discussed in the UFSAR, Section 6.2 (Ref. 2). 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 NSWS is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

The NSWS, in conjunction with the CCW System, also cools the unit from residual heat removal (RHR), as discussed in the UFSAR, Section 5.4 (Ref. 3), from RHR entry conditions to MODE 5 during normal and post accident operations. The time required for this evolution is a function of the number of CCW and RHR System trains that are operating. Thirty six hours after a trip from RTP, one NSWS train is sufficient to remove decay heat during subsequent operations in MODES 5 and 6. This assumes a maximum NSWS temperature, a simultaneous design basis event on the other unit, and the loss of offsite power.

The NSWS satisfies Criterion 3 of 10 CFR 50.36 (Ref. 4).

LCO

Two NSWS 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.

While the NSWS is operating in the normal dual supply and discharge header alignment, an NSWS train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. 1. Both NSWS pumps on the NSWS loop are OPERABLE; or

2. One unit's NSWS pump is OPERABLE and one unit's

LCO (continued)

flowpath to the non essential header, AFW pumps, and Containment Spray heat exchangers are isolated (or equivalent flow restrictions); and

b. The associated piping, valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

The NSWS system is shared between the two units. The shared portions of the system must be OPERABLE for each unit when that unit is in the MODE of Applicability. If a shared NSWS component becomes inoperable, then the Required Actions of this LCO must be entered independently for each unit that is in the MODE of applicability of the LCO, except as noted in a.2 above for operation in the normal dual supply header alignment. In this case, sufficient flow is available, however, this configuration results in inoperabilities within other required systems on one unit and the associated Required Actions must be entered. Use of a NSWS pump and associated diesel generator on a shutdown unit to support continued operation (> 72 hours) of a unit with an inoperable NSWS pump is prohibited.

APPLICABILITY

In MODES 1, 2, 3, and 4, the NSWS is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the NSWS and required to be OPERABLE in these MODES.

In MODES 5 and 6, the requirements of the NSWS are determined by the systems it supports.

ACTIONS

A.1

Condition A is modified by a Note indicating that this Condition is not applicable while in Condition C of this LCO unless entry is directed by Note 2 of Condition C.

If one NSWS train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE NSWS train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE NSWS train could result in loss of NSWS function. Due to the shared nature of the NSWS, both units are required to enter a 72 hour Action when a NSWS Train becomes inoperable on

ACTIONS (continued)

either unit. 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 NSWS train results in an inoperable emergency 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 NSWS train results in an inoperable decay heat removal train (RHR). An example of when these Notes should be applied is with both units' loop 'A' NSWS pumps inoperable, both units' 'A' emergency diesel generators and both units' 'A' RHR systems should be declared inoperable and appropriate Actions entered. 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

While the NSWS is operating in the single supply header alignment, one of the supply headers is removed from service in support of planned maintenance or modification activities associated with the supply header that is taken out of service. In this configuration, each NSWS train is considered OPERABLE with the required NSWS flow to safety related equipment being fed through the remaining OPERABLE NSWS supply header. While the NSWS is operating in the single supply header alignment, an NSWS train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. Both NSWS pumps on the NSWS loop are OPERABLE; and

b. The associated piping (except for the supply header that is taken out of service), valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

If one NSWS supply header is inoperable due to the NSWS being aligned for single supply header operation, the NSWS supply header must be restored to OPERABLE status within 30 days. Dual supply header operation is the normal alignment of the NSWS. The Completion Time of 30 days is supported by probabilistic risk analysis. While in Condition B, the single supply header is adequate to perform the heat removal function for all required safety related equipment for both safety trains. Due to the shared nature of the NSWS, both units are required to enter this Condition when the NSWS is aligned for single supply header operation. In order to prevent the potential for NSWS pump runout, the

ACTIONS (continued)

single NSWS pump flow balance alignment is prohibited while the NSWS is aligned for single supply header operation.

Condition B is modified by three Notes. Note 1 states that entry into this Condition shall only be allowed for pre-planned activities as described in the Bases of this Specification. Condition B is only allowed to be entered in support of planned maintenance or modification activities associated with the supply header that is taken out of service. An example of a situation for which entry into this Condition is allowed is refurbishment or inspection of a supply header. Entry into this Condition is not allowed in response to unplanned events or for other events involving the NSWS. Examples of situations for which entry into this Condition is prohibited are emergent repair of discovered piping leaks and other component failures. For unplanned events or other events involving the NSWS, Condition A must be entered. Note 2 requires immediate entry into Condition A of this LCO if one or more NSWS components become inoperable while in this Condition and one NSWS train remains OPERABLE. With one remaining OPERABLE NSWS train, the NSWS can still perform its safety related function. However, with one inoperable NSWS train, the NSWS cannot be assured of performing its safety related function in the event of a single failure of another NSWS component. The most limiting single failure is the failure of an NSWS pit to automatically transfer from Lake Wylie to the SNSWP during a seismic event. While the loss of any NSWS component subject to the requirements of this LCO can result in the entry into Condition A, the most common example is the inoperability of an NSWS pump. Note 3 requires immediate entry into LCO 3.0.3 if one or more NSWS components become inoperable while in this Condition and no NSWS train remains OPERABLE. In this case, the NSWS cannot perform its safety related function.

Operation of the NSWS in the single supply header alignment while in either the single Pond return header alignment or the single Auxiliary Building discharge header alignment at the same time is prohibited.

<u>C.1</u>

While the NSWS is operating in the single Auxiliary Building discharge header alignment, one of the Unit 2 Auxiliary Building discharge headers is removed from service in support of planned maintenance or modification activities associated with the Auxiliary Building discharge header that is taken out of service. In this configuration, the corresponding (train related) Unit 1 NSWS train is inoperable and the required NSWS flow to safety related equipment is discharged through the remaining OPERABLE NSWS Auxiliary Building discharge header.

BASES

ACTIONS (continued)

When in the single Auxiliary Building discharge header alignment with the NSWS Train A discharge header inoperable, the NSWS piping between valves 1RNP19 and 1RN63A is isolated. Likewise, when in the single Auxiliary Building discharge header alignment with the NSWS Train B discharge header inoperable, the NSWS piping between valves 1RNP20 and 1RN58B is isolated.

Operation of the NSWS in the single Auxiliary Building discharge header alignment while in either the single supply header alignment or the single Pond return header alignment at the same time is prohibited.

If one NSWS train is inoperable due to the NSWS being aligned for single Auxiliary Building discharge header operation, the NSWS train must be restored to OPERABLE status within 14 days. Dual Auxiliary Building discharge header operation is the normal alignment of the NSWS. The Completion Time of 14 days is supported by probabilistic risk analysis. While in Condition C, the single Auxiliary Building discharge header is adequate to perform the heat removal function for all required safety related equipment for its respective safety train. Due to the design of the NSWS, only the operating unit is required to enter this Condition when the NSWS is aligned for single Auxiliary Building discharge header operation. Pre-planned activities requiring entry into this Condition are only performed with Unit 2 in an outage (MODE 5, 6, or defueled).

Condition C is modified by three Notes. Note 1 states that entry into this Condition shall only be allowed for Unit 1 and for pre-planned activities as described in the Bases of this Specification. Condition C is only allowed to be entered in support of planned maintenance or modification activities associated with the Auxiliary Building discharge header that is taken out of service. An example of a situation for which entry into this Condition is allowed is refurbishment or inspection of an Auxiliary Building discharge header. Entry into this Condition is not allowed in response to unplanned events or for other events involving the NSWS. Examples of situations for which entry into this Condition is prohibited are emergent repair of discovered piping leaks and other component failures. For unplanned events or other events involving the NSWS, Condition A must be entered. In addition, Note 1 states that entry into this Condition shall not be allowed while Unit 2 is in MODE 1, 2, 3, or 4. Entry into this Condition is only allowed while the LCO is not applicable to Unit 2. Note 2 requires immediate entry into Condition A of this LCO if one or more Unit 1 required NSWS components become inoperable while in this Condition and one NSWS train remains OPERABLE. With one remaining OPERABLE NSWS train, the NSWS can still perform its safety related

ACTIONS (continued)

function. However, with one inoperable NSWS train, the NSWS cannot be assured of performing its safety related function in the event of a single failure of another NSWS component. While the loss of any NSWS component subject to the requirements of this LCO can result in the entry into Condition A, the most common example is the inoperability of an NSWS pump. This occurs during periodic testing of the emergency diesel generators. Inoperability of an emergency diesel generator renders its associated NSWS pump inoperable. Note 3 requires immediate entry into LCO 3.0.3 if one or more Unit 1 required NSWS components become inoperable while in this Condition and no NSWS train remains OPERABLE. In this case, the NSWS cannot perform its safety related function.

D.1

While the NSWS is operating in the single Pond return header alignment, one of the shared discharge headers from the Aux Bldg to the SNSWP is removed from service in support of planned maintenance or modification activities associated with the Pond return header that is taken out of service. In this configuration, each NSWS train is considered OPERABLE with the required NSWS flow path from safety related equipment through the remaining OPERABLE NSWS Pond return header. The technical justification for the NSWS single Pond return header alignment demonstrates that the NSWS can meet all design flow requirements in response to all design basis accidents. The utilization of the single pond return header has been analyzed in the PRA risk based assessment with no significant increase in risk. While the NSWS is operating in the single Pond return header alignment, an NSWS train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. Both NSWS pumps on the NSWS loop are OPERABLE; and

b. The associated piping (except for the Pond return header that is taken out of service), valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

When in the single Pond return header alignment with the NSWS Train A Pond return header inoperable, the NSWS piping downstream of valves 1RN63A and 1(2)RN846A is isolated. Valve 1RNP20 is locked open, 1RN58B is open with power removed, and 1(2)RN848B are open with power removed to protect against closing that would isolate the discharge flow from both trains.

Similarly, when in the single Pond return header alignment with the

BASES

ACTIONS (continued)

NSWS Train B Pond return header inoperable, the NSWS piping downstream of valves 1RN58B and 1(2)RN848B is isolated. In this case valve 1RNP19 is locked open, 1RN63A is open with power removed, and 1(2)RN846A are open with power removed to protect against closing that would isolate the discharge flow from both trains.

When in the single Pond return header alignment the NSWS System is aligned to the SNSWP, with power removed from pit isolation valves 1RN3A and 1RN4B, to preclude a single active failure that could result in the complete loss of one NSWS pit (two NSWS pumps). Aux Bldg discharge crossover piping valves 1RN53B and 1RN54A are open with power removed to allow both Aux Bldg trains to discharge through one header. Similarly, Unit 1 and Unit 2 diesel generator (DG) crossover valves 1(2)RNP08 and 1(2)RNP09 are locked open to allow both trains of DGs to discharge through one header on each unit. Finally, both Unit 1 and Unit 2 NSWS non-essential headers are isolated.

Operation of the NSWS in the single Pond return header alignment while in either the single supply header alignment or the single Auxiliary Building discharge header alignment at the same time is prohibited.

If one NSWS Pond return header is inoperable due to the NSWS being aligned for single Pond return header operation, the NSWS Pond return header must be restored to OPERABLE status within 30 days. The Completion Time of 30 days is supported by probabilistic risk analysis. While in Condition D, the single Pond return header alignment is adequate to perform the heat removal function for all required safety related equipment for both safety trains of both units. Due to the shared nature of the NSWS, both units are required to enter this Condition when the NSWS is aligned for single Pond return header operation.

Condition D is modified by four Notes. Note 1 states that entry into this Condition shall only be allowed for pre-planned activities. Condition D is only allowed to be entered in support of planned maintenance or modification activities associated with the Pond return header that is taken out of service. An example of a situation for which entry into this Condition is allowed is refurbishment or inspection of a Pond return header. Entry into this Condition is not allowed in response to unplanned events or for other events involving the NSWS. Examples of situations for which entry into this Condition is prohibited are emergent repair of discovered piping leaks and other component failures. For unplanned events or other events involving the NSWS, Condition A must be entered. Note 2 requires immediate entry into Condition A of this LCO if one or more NSWS components become inoperable while in this Condition and

ACTIONS (continued)

one NSWS train remains OPERABLE. With one remaining OPERABLE NSWS train, the NSWS can still perform its safety related function.

However, with one inoperable NSWS train, the NSWS cannot be assured of performing its safety related function in the event of a single failure of another NSWS component. While the loss of any NSWS component subject to the requirements of this LCO can result in the entry into Condition A, the most common example is the inoperability of an NSWS pump. This occurs during periodic testing of the emergency diesel generators. Inoperability of an emergency diesel generator renders its associated NSWS pump inoperable. Note 3 requires immediate entry into LCO 3.0.3 if one or more NSWS components become inoperable while in this Condition and no NSWS train remains OPERABLE. In this case, the NSWS cannot perform its safety related function. Note 4 states that entry into this Condition shall only be allowed for 60 days per 12-month period. This limitation of entry into this Condition is in agreement with inputs to the PRA risk based assessment for the NSWS alignment supporting operation in this Condition.

E.1 and E.2

If the NSWS train cannot be restored to OPERABLE status within the associated Completion Time, or if the NSWS single supply header, single Auxiliary Building discharge header, or single Pond return header cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

ACTIONS (continued)

The following table identifies those actions committed to by Duke Energy in Letter CNS-17-014 dated September 14, 2017 for the approval of License Amendments 300 and 296 for Units 1 and 2, respectively.

#	REGULATORY COMMITMENTS
1	The support system for the NSWS Discharge piping associated with Train 1A in the Auxiliary Building will be maintained such that stress levels are below the threshold for considering a pipe leak under the Pipe Rupture program. This ensures that for all sections where pipe ruptures are postulated that leaks can be isolated with the NSWS continuing to operate with adequate equipment to support shutdown of both units. Catawba NSWS piping stress calculations RNG, RNH, and RNE have been revised to indicate the requirement to maintain this low stress level.
2	To reduce stress at the 1A Component Cooling (KC) Heat Exchanger piping return nozzle location, a 1/4" thick reinforcing pad will be added to the existing reinforcing pad per a plant modification. The 1/4" reinforcing pad must be installed prior to entering NSWS Single Pond Return Header Operation.
3	NSWS Flow Balance testing will take place prior to entering Single Pond Return Header Operation. This will ensure the NSWS is capable of providing adequate cooling water flow to support LOCA loads on one unit, concurrent with the shutdown loads of the other unit - while assuming the most limiting single failure, which is loss of one DG and its associated NSWS Pump.

BASES

ACTIONS (continued)

The following table identifies additional considerations as addressed in the submittals by Duke Energy in Letter CNS-17-014 dated September 14, 2017 and in Letter RA-18-0097 dated August 17, 2018 for the approval of License Amendments 300 and 296 for Units 1 and 2, respectively.

#	ADDITIONAL CONSIDERATIONS
1	During the Completion Time of Condition D, planned or discretionary maintenance that renders one or more NSWS pumps and / or the associated DGs inoperable and unavailable on either train of NSWS is prohibited while in the Single Pond Return Header alignment with one exception. For the DGs, a monthly periodic test is performed to confirm operability. Prior to starting the DG, a "bar and roll" of the DG is performed. This renders the DG inoperable but available, and is allowed while the NSWS is aligned for Single Pond Return Header Operation.
2	The SSCs whose unavailability should be avoided during the Completion Time for Condition D include the following for the opposite train (i.e., opposite the train in the Completion Time, as applicable): • Nuclear Service Water System • Diesel Generators (DGs) • Component Cooling System • Auxiliary Feedwater System • Instrument Air System • Standby Shutdown Facility (SSF) • Residual Heat Removal System • 4160V AC Essential Power • Engineered Safeguards Features Actuation System • Switchyard Unit Tie Power Circuit Breakers

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR is modified by a Note indicating that the isolation of the NSWS components or systems may render those components inoperable, but does not affect the OPERABILITY of the NSWS. Verifying the correct alignment for manual, power operated, and automatic valves in the NSWS flow path provides assurance that the proper flow paths exist for NSWS 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.8.2

This SR verifies proper automatic operation of the NSWS valves on an actual or simulated actuation signal. The signals that cause the actuation are from Safety Injection and Phase 'B' isolation. The NSWS 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 controls. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that states that the SR is not required to be met for valves that are maintained in position to support NSWS single supply header operation, single Auxiliary Building discharge header operation, or single Pond return header operation. When the NSWS is placed in this alignment, certain automatic valves in the system are maintained in position and will not automatically reposition in response to an actuation signal while the NSWS is in this alignment.

SR 3.7.8.3

This SR verifies proper automatic operation of the NSWS pumps on an actual or simulated actuation signal. The signals that cause the actuation are from Safety Injection and Loss of Offsite Power. The NSWS is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.2.
2. UFSAR, Section 6.2.
3. UFSAR, Section 5.4.
4. 10 CFR 50.36, Technical Specifications, (c)(2)(ii)

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Area Ventilation System (CRAVS)

BASES

BACKGROUND

The CRAVS ensures that the Control Room Envelope (CRE) will remain habitable for occupants during and following all credible accident conditions. This function is accomplished by pressurizing the CRE to $\geq$ 1/8 (0.125) inch water gauge with respect to all surrounding areas, filtering the outside air used for pressurization, and filtering a portion of the return air from the CRE to clean up the control room environment.

The CRAVS consists of two independent, redundant trains of equipment. Each train consists of:

- a pressurizing filter train fan (1CRA-PFTF-1 or 2CRA-PFTF-1)
- a filter unit (1CRA-PFT-1 or 2CRA-PFT-1) which includes moisture separator/prefilters, HEPA filters, and carbon adsorbers
- the associated ductwork, dampers/valves, controls, doors, and barriers

Inherent in the CRAVS ability to pressurize the control room is the control room envelope boundary. 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 the 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 the 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. These boundaries must be intact or properly isolated for the CRAVS to function properly.

BASES

BACKGROUND (continued)

The CRAVS can be operated either manually or automatically. Key operated selector switches located in the CRE initiate operation of all train related CRAVS equipment. The selected train is in continuous operation. Outside air for pressurization and makeup to the CRE is supplied from two independent intakes. This outside air is mixed with return air from the CRE before being passed through the filter unit. In the filter unit, moisture separator/prefilters remove any large particles in the air, and any entrained water droplets present. A HEPA filter bank upstream of the carbon adsorber filter bank functions to remove particulates and a second bank of HEPA filters follow the carbon adsorber to collect carbon fines. Only the upstream HEPA filters and carbon adsorber bank are credited in the analysis. A heater is included within each filter train to reduce the relative humidity of the airstream, although no credit is taken in the safety analysis. The heaters are not required for OPERABILITY since the carbon laboratory tests are performed at 95% relative humidity, but have been maintained in the system to provide additional margin (Ref. 9). Testing per ASTM D3803-1989 at 30°C and 95% relative humidity ensures that the filter efficiency is unaffected by moisture. Periodic operation ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action.

Upon receipt of an Engineered Safety Feature (ESF) signal, the selected CRAVS train continues to operate and the pressurizing filter train fan of the non-selected train is started. This assures control room pressurization, assuming an active failure of one of the pressurizing filter train fans.

The outside air for pressurization is continuously monitored for the presence of smoke, radiation, or chlorine by non-safety related detectors. If smoke, radiation, or chlorine is detected in an outside air intake, an alarm is received within the CRE, alerting the operators of this condition. The operator will take the required action to close the affected intake, if necessary, per the guidance of the Annunciator Response Procedures.

A single CRAVS train is capable of pressurizing the CRE to greater than or equal to 0.125 inches water gauge. The CRAVS is designed in accordance with Seismic Category 1 requirements. The CRAVS operation in maintaining the CRE habitable is discussed in the UFSAR, Sections 6.4 and 9.4.1 (Refs. 1 and 2).

The CRAVS is designed to maintain a habitable environment in the CRE for 30 days of continuous occupancy after a DBA without exceeding a 5 rem total effective dose equivalent (TEDE).

BASES

APPLICABLE SAFETY ANALYSES

The CRAVS components are arranged in redundant, safety related ventilation trains. The CRAVS 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 UFSAR, Chapter 15 (Ref. 3).

The CRAVS provides protection from smoke and hazardous chemicals to 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). The evaluation of 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. 9).

The worst case single active failure of a component of the CRAVS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function.

The CRAVS satisfies Criterion 3 of 10 CFR 50.36 (Ref. 4).

LCO

Two independent and redundant CRAVS trains are required to be OPERABLE to ensure that at least one is available assuming 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 to the CRE occupants in the event of a large radioactive release.

Each CRAVS train is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE in both trains. A CRAVS train is OPERABLE when the associated:

a. Pressurizing filter train fan is OPERABLE;

b. HEPA filters and carbon 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 CRAVS 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 the CRE occupants are protected from hazardous chemicals and smoke.

BASES

LCO (continued)

The CRAVS is shared between the two units. The system must be OPERABLE for each unit when that unit is in the MODE of Applicability. If a CRAVS component becomes inoperable, then the Required Actions of this LCO must be entered independently for each unit that is in the MODE of Applicability of the LCO.

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 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, the CRAVS must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA.

During movement of irradiated fuel assemblies, the CRAVS must be OPERABLE to cope with the release from a fuel handling accident.

ACTIONS

A.1

When one CRAVS 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 CRAVS train is adequate to perform the CRE protection function. However, the overall reliability is reduced because a single failure in the OPERABLE CRAVS train could result in loss of CRAVS 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.

ACTIONS (continued)

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 TEDE), 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.

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 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 CRAVS or CRE boundary train cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

ACTIONS (continued)

D.1

In MODE 5 or 6, if the inoperable CRAVS train cannot be restored to OPERABLE status within the required Completion Time, or during movement of irradiated fuel assemblies, action must be taken to immediately place the OPERABLE CRAVS train in operation. This action ensures that the operating (or running) train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected.

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 risk. This does not preclude the movement of fuel to a safe position.

E.1

In MODE 5 or 6, or during movement of irradiated fuel assemblies, with two CRAVS trains inoperable, or with one or more CRAVS 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.

F.1

If both CRAVS trains are inoperable in MODE 1, 2, 3, or 4, for reasons other than Condition B, the CRAVS may not be capable of performing the intended function and the unit 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. Operation for ≥ 15 continuous minutes demonstrates OPERABILITY of the system. Periodic operation ensures that blockage, fan or motor failure, or excessive vibration can be detected for correction action. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.10.2

This SR verifies that the required CRAVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The CRAVS filter tests are in accordance with Regulatory Guide 1.52 (Ref. 5). The VFTP includes testing the performance of the HEPA filter and carbon adsorber efficiencies and the physical properties of the activated carbon. Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.10.3

This SR verifies that each CRAVS train starts and operates on an actual or simulated actuation signal. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

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 TEDE 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. 9), which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 7). 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. 8). 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. UFSAR, Section 6.4.
2. UFSAR, Section 9.4.1.
3. UFSAR, Chapter 15.
4. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).
5. Regulatory Guide 1.52, Rev. 2.
6. Catawba Nuclear Station License Amendments 90/84 for Units 1/2, August 23, 1991.

BASES

REFERENCES (continued)

7. NEI 99-03, "Control Room Habitability Assessment", June 2001.

8. 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).

9. Regulatory Guide 1.196, Rev. 1.

B 3.7 PLANT SYSTEMS

B 3.7.11 Control Room Area Chilled Water System (CRACWS)

BASES

BACKGROUND

The CRACWS provides temperature control for the control room and the control room area.

The CRACWS consists of two independent and redundant trains that provide cooling to the control room and control room area. Each train consists of a chiller package, chilled water pump, and air handling units with cooling coils. Chilled water is passed through the cooling coils of the air handling unit to cool the air. Electric duct heaters are then used to control the supply air temperature.

The CRACWS provides both normal and emergency cooling to the control room and control room area. A single train will provide the required temperature control to maintain the control room approximately 74°F. The CRACWS operation in maintaining the control room temperature is discussed in the UFSAR, Section 9.4 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the CRACWS is to maintain the control room temperature for 30 days of continuous occupancy.

The CRACWS components are arranged in redundant, safety related trains. During emergency operation, the CRACWS maintains the temperature between 72°F and 85°F. A single active failure of a component of the CRACWS, 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. The CRACWS is designed in accordance with Seismic Category I requirements. The CRACWS is 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.

The CRACWS satisfies Criterion 3 of 10 CFR 50.36 (Ref. 2).

BASES

LCO

Two independent and redundant trains of the CRACWS 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 CRACWS is considered to be OPERABLE when the individual components necessary to maintain the control room temperature are OPERABLE in both trains. These components include a chiller package, chilled water pump, and air handling unit. In addition, the CRACWS must be OPERABLE to the extent that air circulation can be maintained.

The CRACWS is shared between the two units. The system must be OPERABLE for each unit when that unit is in the MODE of Applicability. If a CRACWS component becomes inoperable, then the Required Actions of this LCO must be entered independently for each unit that is in the MODE of applicability of the LCO.

APPLICABILITY

In MODES 1, 2, 3, 4, 5, and 6, and during movement of recently irradiated fuel assemblies, the CRACWS must be OPERABLE to ensure that the control room temperature will not exceed equipment operational requirements following a design basis accident. The CRACWS is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 72 hours) due to radioactive decay.

ACTIONS

A.1

With one CRACWS train inoperable, action must be taken to restore OPERABLE status within 30 days. In this Condition, the remaining OPERABLE CRACWS train is adequate to maintain the control room temperature within limits. However, the overall reliability is reduced because a single failure in the OPERABLE CRACWS train could result in loss of CRACWS function. The 30 day Completion Time is based on the low probability of an event, the consideration that the remaining train can provide the required protection, and that alternate safety or nonsafety related cooling means are available.

BASES

ACTIONS (continued)

B.1 and B.2

In MODE 1, 2, 3, or 4, if the inoperable CRACWS train cannot be restored to OPERABLE status within the required Completion Time, the unit must be placed in a MODE that minimizes the risk. To achieve this status, the unit 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 unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1 and C.2

In MODE 5 or 6, or during movement of recently irradiated fuel, if the inoperable CRACWS train cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE CRACWS train must be placed in operation immediately. This action ensures that the remaining train is OPERABLE, 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. 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 recently irradiated fuel assemblies, with two CRACWS trains inoperable, action must be taken immediately to suspend activities that could result in a release of radioactivity. 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 CRACWS trains are inoperable in MODE 1, 2, 3, or 4, the control room CRACWS may not be capable of performing its intended function. Therefore, LCO 3.0.3 must be entered immediately.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

This SR verifies that the heat removal capability of the system is sufficient to maintain the temperature in the control room at or below 90°F. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.4.
2. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).
3. 10 CFR 50.67, Accident source term.
4. Regulatory Guide 1.183, Revision 0.

B 3.7 PLANT SYSTEMS

B 3.7.12 Auxiliary Building Filtered Ventilation Exhaust System (ABFVES)

BASES

BACKGROUND

The ABFVES consists of two independent and redundant trains. Each train consists of a heater demister section and a filter unit section. The heater demister section consists of a prefilter/moisture separator (to remove entrained water droplets) and an electric heater (to reduce the relative humidity of air entering the filter unit). The filter unit section consists of a prefilter, an upstream HEPA filter, an activated carbon adsorber (for the removal of gaseous activity, principally iodines), a downstream HEPA, and a fan. The downstream HEPA filter is not credited in the accident analysis, but serves to collect carbon fines. Ductwork, valves or dampers, and instrumentation also form part of the system. Following receipt of a safety injection (SI) signal, the system isolates non safety portions of the ABFVES and exhausts air only from the Emergency Core Cooling System (ECCS) pump rooms.

The ABFVES is normally aligned to bypass the system HEPA filters and carbon adsorbers. During emergency operations, the ABFVES dampers are realigned to the filtered position, and fans are started to begin filtration. During emergency operations, the ABFVES dampers are realigned to isolate the non-safety portions of the system and only draw air from the ECCS pump rooms, as well as the Elevation 522 pipe chase, and Elevation 543 and 560 mechanical penetration rooms.

The ABFVES is discussed in the UFSAR, Sections 6.5, 9.4, 14.4, and 15.6 (Refs. 1, 2, 3, and 4, respectively) since it may be used for normal, as well as post accident, atmospheric cleanup functions. The heaters are not required for OPERABILITY, since the laboratory test of the carbon is performed at 95% relative humidity, but have been maintained in the system to provide additional margin (Ref. 9). Testing per ASTM D3803-1989 at 30°C and 95% relative humidity ensures that the filter efficiency is unaffected by moisture.

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the ABFVES is established by the large break LOCA. The system evaluation assumes filtered and unfiltered leak rates in the Auxiliary Building throughout the accident. In such a case, the system limits radioactive release to within the 10 CFR 50.67 (Ref. 6) limits. The analysis of the effects and consequences of a large break LOCA is presented in Reference 4.

The ABFVES satisfies Criterion 3 of 10 CFR 50.36 (Ref. 7).

LCO

Two independent and redundant trains of the ABFVES are required to be OPERABLE to ensure that at least one is available, assuming that a single failure disables the other train coincident with a loss of offsite power. Total system failure could result in the atmospheric release from the ECCS pump rooms exceeding 10 CFR 50.67 limits in the event of a Design Basis Accident (DBA).

ABFVES is considered OPERABLE when the individual components necessary to maintain the ECCS pump rooms filtration are OPERABLE in both trains.

An ABFVES train is considered OPERABLE when its associated:

a. Fan is OPERABLE;

b. HEPA filters and carbon adsorbers are capable of performing their filtration functions; and

c. Ductwork, valves, and dampers are OPERABLE and air circulation can be maintained.

The ABFVES fans power supply is provided by buses which are shared between the two units.

BASES

LCO (continued)

The LCO is modified by a Note allowing the ECCS pump rooms pressure boundary to be opened intermittently under administrative controls. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls consist of stationing a dedicated individual at the opening who is in continuous communication with the control room. This individual will have a method to rapidly close the opening when a need for ECCS pump rooms pressure boundary isolation is indicated.

APPLICABILITY

In MODES 1, 2, 3, and 4, the ABFVES is required to be OPERABLE consistent with the OPERABILITY requirements of the ECCS.

In MODE 5 or 6, the ABFVES is not required to be OPERABLE since the ECCS is not required to be OPERABLE.

ACTIONS

A.1

With one ABFVES train inoperable, action must be taken to restore OPERABLE status within 7 days. During this time, the remaining OPERABLE train is adequate to perform the ABFVES function.

The 7 day Completion Time is appropriate because the risk contribution is less than that for the ECCS (72 hour Completion Time), and this system is not a direct support system for the ECCS. 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.

Concurrent failure of two ABFVES trains would result in the loss of functional capability; therefore, LCO 3.0.3 must be entered immediately.

B.1

If the ECCS pump rooms pressure boundary is inoperable such that the ABFVES trains cannot establish or maintain the required pressure, action must be taken to restore an OPERABLE ECCS pump rooms pressure boundary within 24 hours. During the period that the ECCS pump rooms pressure boundary is inoperable, appropriate compensatory measures (consistent with the intent, as applicable, of GDC 19, 60, 64, and 10 CFR 50.67) should be utilized to protect plant personnel from potential

ACTIONS (continued)

hazards such as radioactive contamination, toxic chemicals, smoke, temperature and relative humidity, and physical security. Preplanned measures should be available to address these concerns for intentional and unintentional entry into the condition. The 24 hour Completion Time is reasonable based on the low probability of a DBA occurring during this time period and the use of compensatory measures. The 24 hour Completion Time is a typically reasonable time to diagnose, plan and possibly repair, and test most problems with the ECCS pump rooms pressure boundary.

C.1 and C.2

If the ABFVES train or ECCS pump rooms pressure boundary cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

Systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not severe, testing each train once a month provides an adequate check on this system. Operation for ≥ 15 continuous minutes demonstrates OPERABILITY of the system. Periodic operation ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.12.2

This SR verifies that the required ABFVES testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The ABFVES filter tests are in accordance with Reference 5. The VFTP includes testing HEPA filter performance, carbon adsorbers efficiency, system flow rate, and the physical properties of the activated carbon (general use and following specific operations). The system flow rate determination and in-place testing of the filter unit components is performed in the normal operating alignment with both trains in operation. Flow through each filter unit in this alignment is approximately 30,000 cfm. The normal operating alignment has been chosen to minimize normal radiological protection concerns that occur when the system is operated in an abnormal alignment for an extended period of time. Operation of the system in other alignments may alter flow rates to the extent that the 30,000 cfm ±10% specified in Technical Specification 5.5.11 will not be met. Flow rates outside the specified band under these operating alignments will not require the system to be considered inoperable.

Certain postulated failures and post accident recovery operational alignments may result in post accident system operation with only one train of ABFVES in a “normal” alignment. Under these conditions system flow rate is expected to increase above the normal flow band specified in Technical Specification 5.5.11. An analysis has been performed which conservatively predicts the maximum flow rate under these conditions is approximately 37,000 cfm. 37,000 cfm corresponds to a face velocity of approximately 48 ft/min that is significantly more than the normal 40 ft/min velocity specified in ASTM D3803-1989 (Ref. 10). Therefore, the laboratory test of the carbon penetration is performed in accordance with ASTM D3803-1989 and Generic Letter 99-02 at a face velocity of 48 ft/min. These test results are to be adjusted for a 2.27 inch bed using the methodology presented in ASTM D3803-1989 prior to comparing them to the Technical Specification 5.5.11 limit. Specific test Frequencies and additional information are discussed in detail in the VFTP.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.12.3

This SR verifies that each ABFVES train starts and operates with flow through the HEPA filters and carbon adsorbers on an actual or simulated actuation signal. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.7.12.4

This SR verifies the pressure boundary integrity of the ECCS pump rooms. The following rooms are considered to be ECCS pump rooms (with respect to the ABFVES): centrifugal charging pump rooms, safety injection pump rooms, residual heat removal pump rooms, and the containment spray pump rooms. Although the containment spray system is not normally considered an ECCS system, it is included in this ventilation boundary because of its accident mitigation function which requires the pumping of post accident containment sump fluid. The Elevation 522 pipe chase area is also maintained at a negative pressure by the ABFVES. Since the Elevation 543 and 560 mechanical penetration rooms communicate directly with the Elevation 522 pipe chase area, these penetration rooms are also maintained at a negative pressure by the ABFVES. The ability of the system to maintain the ECCS pump rooms at a negative pressure, with respect to potentially unfiltered adjacent areas, is periodically tested to verify proper functioning of the ABFVES. Upon receipt of a safety injection signal to initiate LOCA operation, the ABFVES is designed to maintain a slight negative pressure in the ECCS pump rooms, with respect to adjacent areas, to prevent unfiltered LEAKAGE. The ABFVES will continue to operate in this mode until the safety injection signal is reset. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

BASES

REFERENCES

1. UFSAR, Section 6.5.

2. UFSAR, Section 9.4.

3. UFSAR, Section 14.4.

4. UFSAR, Section 15.6.

5. Regulatory Guide 1.52 (Rev. 2).

6. 10 CFR 50.67.

7. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).

8. Not used.

9. Catawba Nuclear Station License Amendments 90/84 for Units 1/2, August 23, 1991.

10. ASTM D3803-1989.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources—Operating

BASES

BACKGROUND

The unit Essential Auxiliary 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 is divided into redundant load groups (trains) so that the loss of any one group does not prevent the minimum safety functions from being performed. Each train has connections to two preferred offsite power sources and a single DG.

At the 600V level of the onsite Class 1E AC Distribution System, each unit has one motor control center (MCC), 1EMXG and 2EMXH, that each supply power to a train of shared systems. The term shared systems is defined as the shared components of Train A or Train B of Nuclear Service Water System (NSWS), Control Room Area Ventilation System (CRAVS), Control Room Area Chilled Water System (CRACWS) and Auxiliary Building Filtered Ventilation Exhaust System (ABFVES) whose power supply can be swapped between the Units. The MCC 1EMXG is normally aligned to receive power from load center 1ELXA but if desired or required to maintain operability of the Train A shared systems, can be swapped to receive power from load center 2ELXA. The MCC 2EMXH is normally aligned to receive power from load center 2ELXB but if desired or required to maintain operability of the Train B shared systems, can be swapped to receive power from load center 1ELXB. The four NSWS pumps (1A, 2A, 1B and 2B) are shared components that receive power at the Unit and Train specific 4160V level of the onsite Class 1E AC Distribution System and whose power supply cannot be swapped between the Units. Therefore, the four NSWS pumps are not part of the “shared systems,” as defined above, because the power supply for a particular NSWS pump cannot come from the opposite unit.

There are also provisions to accommodate the connecting of the Emergency Supplemental Power Source (ESPS) to one train of either unit’s Class 1E AC Distribution System. The ESPS consists of two 50%

BACKGROUND (continued)

capacity non-safety related commercial grade DGs. Manual actions are required to align the ESPS to the station and only one of the station's four onsite Class 1E Distribution System trains can be supplied by the ESPS at any given time. The ESPS is made available to support extended Completion Times in the event of an inoperable DG as well as a defense-in-depth source of AC power to mitigate a station blackout event. The ESPS would remain disconnected from the Class 1E AC Distribution System unless required for supplemental power to one of the four 4.16 kV ESF buses.

From the transmission network, two electrically and physically separated circuits provide AC power, through step down station auxiliary transformers, to the 4.16 kV ESF buses. A detailed description of the offsite power network and the circuits to the Class 1E ESF buses is found in the UFSAR, Chapter 8 (Ref. 2).

A qualified offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E ESF bus(es).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Class 1E Distribution System. Within 1 minute after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service via the load sequencer.

The onsite standby power source for each 4.16 kV ESF bus is a dedicated DG. DGs A and B are dedicated to ESF buses ETA and ETB, respectively. A DG starts automatically on a safety injection (SI) signal (i.e., low pressurizer pressure or high containment pressure signals) or on an ESF bus degraded voltage or undervoltage 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 bus after offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with an SI signal. With no SI signal, there is a 10 minute delay between degraded voltage signal and the DG start signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, a sequencer strips loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

BACKGROUND (continued)

In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in the process. Approximately 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for Train A and Train B DGs satisfy the requirements of Regulatory Guide 1.9 (Ref. 3). The continuous service rating of each DG is 7000 kW with 10% overload permissible for up to 2 hours in any 24 hour period. The ESF loads that are powered from the 4.16 kV ESF buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the UFSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, 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 unit. This results in maintaining at least one train of the onsite or offsite AC sources OPERABLE during Accident conditions in the event of:

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

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36 (Ref. 6).

LCO

Two qualified circuits between the offsite transmission network and the onsite Essential Auxiliary Power System and separate and independent DGs for each train ensure availability of the required power to shut down

LCO (continued)

the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Additionally, the qualified circuit(s) between the offsite transmission network and the opposite unit onsite Essential Auxiliary Power System when necessary to power shared systems and the NSWS pump(s) and the opposite unit DG(s) when necessary to power shared systems and the NSWS pump(s) ensure 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.

Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit.

In addition, one required automatic load sequencer per train must be OPERABLE.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses.

The 4.16 kV essential system is divided into two completely redundant and independent trains designated A and B, each consisting of one 4.16 kV switchgear assembly, three 4.16 kV/600 V transformers, two 600 V load centers, and associated loads.

Normally, each Class 1E 4.16 kV switchgear is powered from its associated non-Class 1E train of the 6.9 kV Normal Auxiliary Power System as discussed in "6.9 kV Normal Auxiliary Power System" in Chapter 8 of the UFSAR (Ref. 2). Additionally, a standby source of power to each 4.16 kV essential switchgear, not required by General Design Criterion 17, is provided from the 6.9 kV system via two separate and independent 6.9/4.16 kV transformers. These transformers are shared between units and provide the capability to supply a standby source of preferred power to each unit's 4.16 kV essential switchgear from either unit's 6.9 kV system. A key interlock scheme is provided to preclude the possibility of connecting the two units together at either the 6.9 or 4.16 kV level.

Each train of the 4.16 kV Essential Auxiliary Power System is also provided with a separate and independent emergency diesel generator to supply the Class 1E loads required to safely shut down the unit following a design basis accident. Additionally, each diesel generator is capable of supplying its associated 4.16 kV blackout switchgear through a connection with the 4.16 kV essential switchgear.

LCO (continued)

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 11 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 ESF buses. These capabilities are required to be met from a variety of initial conditions such as DG in standby with the engine hot and DG in standby with the engine at ambient conditions. Additional DG capabilities must be demonstrated to meet required Surveillance, e.g., capability of the DG to revert to standby status on an ECCS signal while operating in parallel test mode.

Proper sequencing of loads, including tripping of nonessential 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.

For the offsite AC sources, separation and independence are provided to the extent practical.

LCO 3.8.1.c and LCO 3.8.1.d both use the word “necessary” to clarify that the qualified offsite circuit(s) in LCO 3.8.1.c and the DG(s) from the opposite unit in LCO 3.8.1.d are required to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA.

LCO 3.8.1.c specifies that the qualified circuit(s) between the offsite transmission network and the opposite unit’s Onsite Essential Auxiliary Power System be OPERABLE when necessary to supply power to the shared systems and NSWS pump(s). LCO 3.8.1.d specifies that the DG(s) from the opposite unit be OPERABLE when necessary to supply power to the shared systems and NSWS pump(s). The LCO 3.8.1.c AC sources in one train must be separate and independent (to the extent possible) of the LCO 3.8.1.c AC sources in the other train. These requirements, in conjunction with the requirements for the applicable unit AC electrical power sources in LCO 3.8.1.a and LCO 3.8.1.b, ensure that power is available to two trains of the shared NSWS, CRAVS, CRACWS and ABFVES, as well as to the NSWS pump(s).

With no equipment inoperable, two LCO 3.8.1.c AC sources are required to be OPERABLE and two LCO 3.8.1.d AC sources are required to be OPERABLE for each unit. For example, with both units in MODE 1, Unit 1 LCO 3.8.1.c is met by an OPERABLE 2A offsite circuit and an

LCO (continued)

OPERABLE 2B offsite circuit. LCO 3.8.1.d is met by an OPERABLE 2A DG and an OPERABLE 2B DG. In a normal plant alignment, the 2A offsite circuit and the 2A DG are relied upon as the normal and emergency power supplies for the 2A NSWS Pump, a shared component. The 2B offsite circuit and the 2B DG are relied upon as the normal and emergency power supplies for the 2B NSWS Pump, a shared component, as well as the Train B shared systems that are powered at the 600V level of the onsite Class 1E AC Distribution System. For Unit 2, LCO 3.8.1.c is met by an OPERABLE 1A offsite circuit and an OPERABLE 1B offsite circuit. LCO 3.8.1.d is met by an OPERABLE 1A DG and an OPERABLE 1B DG. In a normal plant alignment, the 1A offsite circuit and the 1A DG are relied upon as the normal and emergency power supplies for the 1A NSWS Pump, a shared component, as well as the Train A shared systems that are powered at the 600V level of the onsite Class 1E AC Distribution System. The 1B offsite circuit and the 1B DG are relied upon as the normal and emergency power supplies for the 1B NSWS Pump, shared component.

APPLICABILITY

The AC sources and sequencers 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.

A Note has been added taking exception to the Applicability requirements for the required AC sources in LCO 3.8.1.c and LCO 3.8.1.d provided the associated shared systems and NSWS pump(s) are inoperable. This exception is intended to allow declaring the shared systems and NSWS pump(s) supported by the opposite unit inoperable either in lieu of declaring the opposite unit AC sources inoperable, or at any time subsequent to entering ACTIONS for an inoperable opposite unit AC source.

This exception is acceptable since, with the shared systems and NSWS pump(s) supported by the opposite unit inoperable and the associated ACTIONS entered, the opposite unit AC sources provide no additional assurance of meeting the above criteria.
The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable DG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable DG and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

To ensure a highly reliable power source remains with one LCO 3.8.1.a offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining 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 not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition E, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, which only applies if the train cannot be powered from an 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 train. This includes motor driven auxiliary feedwater pumps. The turbine driven auxiliary feedwater pump is required to be considered a redundant required feature, and, therefore, required to be determined OPERABLE by this Required Action. Three independent AFW pumps are required to ensure the availability of decay heat removal capability for all events accompanied by a loss of offsite power and a single failure. System design is such that the remaining OPERABLE motor driven auxiliary feedwater pump is not by itself capable of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

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 it loads; and

b. A required feature on the other train is inoperable.

ACTIONS (continued)

If at any time during the existence of Condition A (one LCO 3.8.1.a offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

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 unit to transients associated with shutdown.

The remaining OPERABLE offsite circuits 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. 7), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit 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 LCO 3.8.1.a or LCO 3.8.1.b. If Condition A is entered while, for instance, a LCO 3.8.1.b DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days. This could lead to a total of 17 days, since initial failure to meet LCO 3.8.1.a or LCO 3.8.1.b, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 14 days (for a total of 31 days) allowed

ACTIONS (continued)

prior to complete restoration of LCOs 3.8.1.a and 3.8.1.b. The 17 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 17 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 LCO 3.8.1.a or LCO 3.8.1.b was initially not met, instead of at the time Condition A was entered.

B.1

It is required to administratively verify the LCO 3.8.1.d DG(s) OPERABLE within 1 hour and to continue this action once per 12 hours thereafter until restoration of the required LCO 3.8.1.b DG is accomplished. This verification provides assurance that the LCO 3.8.1.d DG is capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

If one LCO 3.8.1.d DG is discovered to be inoperable when performing the administrative verification of operability, then Condition D is entered for that DG. If two LCO 3.8.1.d DGs are discovered to be inoperable when performing the administrative verification of operability, then Condition G is entered.

B.2

To ensure a highly reliable power source remains with an inoperable LCO 3.8.1.b DG, 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 offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.3

Required Action B.3 is intended to provide assurance that a loss of offsite power, during the period that a LCO 3.8.1.b 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

ACTIONS (continued)

motor driven auxiliary feedwater pumps. The turbine driven auxiliary feedwater pump is required to be considered a redundant required feature, and, therefore, required to be determined OPERABLE by this Required Action. Three independent AFW pumps are required to ensure the availability of decay heat removal capability for all events accompanied by a loss of offsite power and a single failure. System design is such that the remaining OPERABLE motor driven auxiliary feedwater pump is not by itself capable of providing 100% of the auxiliary feedwater flow assumed in the safety analysis. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable LCO 3.8.1.b DG.

The Completion Time for Required Action B.3 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 LCO 3.8.1.b DG exists; and

b. A required feature on the other train (Train A or Train B) is inoperable.

If at any time during the existence of this Condition (one LCO 3.8.1.b DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required LCO 3.8.1.b DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the OPERABLE DG, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is Acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

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.

ACTIONS (continued)

B.4.1 and B.4.2

Required Action B.4.1 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. If the cause of inoperability exists on other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition D and/or G of LCO 3.8.1, as applicable, would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.4.1 or B.4.2, the problem investigation process will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

These Conditions are not required to be entered if the inoperability of the DG is due to an inoperable support system, an independently testable component, or preplanned testing or maintenance. If required, these Required Actions are to be completed regardless of when the inoperable DG is restored to OPERABLE status.

According to Generic Letter 84-15 (Ref. 8), 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

B.5

In order to extend the Completion Time for an inoperable DG from 72 hours to 14 days, it is necessary to ensure the availability of the ESPS within 1 hour of entry into TS 3.8.1 LCO and every 12 hours thereafter.

Since Required Action B.5 only specifies “evaluate,” discovering the ESPS unavailable does not result in the Required Action being not met (i.e. the evaluation is performed). However, on discovery of an unavailable ESPS, the Completion Time for Required Action B.6 starts the 72 hour and/or 24 hour clock.

ESPS availability requires that:

1) The load test has been performed within 30 days of entry into the ACTIONS (continued)

ACTIONS (continued)

extended Completion Time. The Required Action evaluation is met with an administrative verification of this prior to testing; and

2) ESPS fuel tank level is verified locally to be ≥ 24 hour supply; and

3) ESPS supporting system parameters for starting and operating are verified to be within required limits for functional availability (e.g., battery state of charge).

The ESPS is not used to extend the Completion Time for more than one inoperable DG at any one time.

B.6

In accordance with Branch Technical Position 8-8 (Ref. 14), operation may continue in Condition B for a period that should not exceed 14 days, provided a supplemental AC power source is available.

In Condition B, the remaining OPERABLE DGs, available ESPS and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 day 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.

If the ESPS is or becomes unavailable with an inoperable LCO 3.8.1.b DG, then action is required to restore the ESPS to available status or to restore the DG to OPERABLE status within 72 hours from discovery of unavailable ESPS. However, if the ESPS unavailability occurs at or sometime after 48 hours of continuous LCO 3.8.1.b DG inoperability, then the remaining time to restore the ESPS to available status or to restore the DG to OPERABLE status is limited to 24 hours.

The 72 hour and 24 hour Completion Times allow for an exception to the normal “time zero” for beginning the allowed outage time “clock.” The 72 hour Completion Time only begins on discovery that both:

a. An inoperable DG exists; and
b. ESPS is unavailable.

The 24 hour Completion Time only begins on discovery that:

a. An inoperable DG exists for ≥ 48 hours; and
b. ESPS is unavailable.

ACTIONS (continued)

Therefore, when one LCO 3.8.1.b DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 72 hours to 14 days if ESPS is verified available for backup operation.

The fourth Completion Time for Required Action B.6 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 LCO 3.8.1.a or LCO 3.8.1.b. If Condition B is entered while, for instance, a LCO 3.8.1.a 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 17 days, since initial failure to meet LCO 3.8.1.a or LCO 3.8.1.b, to restore the DG. At this time, a LCO 3.8.1.a offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of LCO 3.8.1.a and LCO 3.8.1.b. The 17 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.a or LCO 3.8.1.b. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 14 day and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.3, 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 LCO 3.8.1.a or LCO 3.8.1.b was initially not met, instead of at the time Condition B was entered.

C.1

Condition C addresses the inoperability of the LCO 3.8.1.c qualified offsite circuit(s) between the offsite transmission network and the opposite unit’s Onsite Essential Auxiliary Power System when the LCO 3.8.1.c qualified offsite circuit(s) is necessary to supply power to the shared systems and NSWS pump(s). If Condition C is entered concurrently with the inoperability of LCO 3.8.1.d DG(s) the NOTE requires the licensed operator to evaluate if the TS 3.8.9 “Distribution Systems – Operating” requirement that “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” continues to be met. In the case where the inoperable LCO 3.8.1.c qualified offsite circuit and inoperable LCO 3.8.1.d DG are associated with the same train there is no longer assurance that train of

ACTIONS (continued)

"Distribution Systems – Operating" can be energized to the proper voltage and therefore TS 3.8.9 Condition A must be entered.

To ensure a highly reliable power source remains with one required LCO 3.8.1.c offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining 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 not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition A and E, as applicable, for the two offsite circuits inoperable, is entered.

<u>C.2</u>

Required Action C.2, which only applies if the train cannot be powered from an 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 for the NSWS (including the NSWS pump), CRAVS, CRACWS or the ABFVES. The Completion Time for Required Action C.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. NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES on the other train that has offsite power is inoperable.

If at any time during the existence of Condition C (one required LCO 3.8.1.c offsite circuit inoperable) a train of NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES becomes inoperable, this Completion Time begins to be tracked.

Discovering no offsite power to one train of the onsite Class 1E Electrical Power Distribution System coincident with one train of NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES that is 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 unit to transients associated with shutdown.

The remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to Train A and Train B of the onsite Class 1E

ACTIONS (continued)

Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES. 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.

C.3

Consistent with the time provided in ACTION A, operation may continue in Condition C for a period that should not exceed 72 hours. With one required LCO 3.8.1.c 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 unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

If the LCO 3.8.1.c required offsite circuit cannot be restored to OPERABLE status within 72 hours, then Condition I must be entered immediately.

D.1

Condition D addresses the inoperability of the LCO 3.8.1.d DG(s) aligned to the opposite unit Onsite Essential Auxiliary Power System that is supplying power to a train of shared systems and to the respective NSWS pump(s). If Condition D is entered concurrently with the inoperability of LCO 3.8.1.c qualified offsite circuit, the NOTE requires the licensed operator to evaluate if the TS 3.8.9 “Distribution Systems – Operating” requirement that “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” continues to be met. In the case where the inoperable LCO 3.8.1.d DG and inoperable LCO 3.8.1.c qualified offsite circuit are associated with the same train there is no longer assurance that train of “Distribution Systems – Operating” can be energized to the proper voltage and therefore TS 3.8.9 Condition A must be entered.

It is required to administratively verify the LCO 3.8.1.b safety-related DGs OPERABLE and the opposite unit’s DG OPERABLE within one hour and to continue this action once per 12 hours thereafter until restoration of the required LCO 3.8.1.d DG and the opposite unit’s DG is accomplished. This verification provides assurance that the LCO 3.8.1.b safety-related

ACTIONS (continued)

DGs and the opposite unit's DG is capable of supplying the onsite Class 1E AC Electrical Power Distribution System.

If one LCO 3.8.1.b DG is discovered to be inoperable when performing the administrative verification of operability, then Condition B is entered for that DG. If two LCO 3.8.1.b DGs are discovered to be inoperable, then Condition G is entered. If one LCO 3.8.1.b DG that provides power to shared systems is discovered inoperable and the LCO 3.8.1.d DG that was initially inoperable provides power to shared systems, then Condition G is also entered. If one LCO 3.8.1.b DG that provides power to shared systems is discovered inoperable and the LCO 3.8.1.d DG that was initially inoperable only provides power to its respective NSWS pump, then Condition B is entered for the LCO 3.8.1.b DG.

If the second LCO 3.8.1.d DG, which is the other opposite unit's DG, is found to be inoperable when performing the administrative verification of operability, then Condition G is entered.

<u>D.2</u>

To ensure a highly reliable power source remains with one required LCO 3.8.1.d DG inoperable, it is necessary to verify the OPERABILITY 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 not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

<u>D.3</u>

Required Action D.3 is intended to provide assurance that a loss of offsite power, during the period one required LCO 3.8.1.d DG is inoperable, does not result in a complete loss of safety function for the NSWS (including the NSWS pump), CRAVS, CRACWS or the ABFVES. The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable LCO 3.8.1.d DG exists; and

b. NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES on the other train that has emergency power is inoperable.

ACTIONS (continued)

If at any time during the existence of this Condition (the LCO 3.8.1.d DG inoperable) a train of NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES becomes inoperable, this Completion Time begins to be tracked.

Discovering the LCO 3.8.1.d DG inoperable coincident with one train of NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES that is associated with the other train that has emergency power results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

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 NSWS (including the NSWS pump), CRAVS, CRACWS or ABFVES may have been lost; however, function has not been lost. The four hour Completion Time also takes into account the capacity and capability of the remaining NSWS (including the NSWS pump), CRAVS, CRACWS and ABFVES train, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

<u>D.4.1 and D.4.2</u>

Required Action D.4.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG(s), SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition B and I of LCO 3.8.1, as applicable, would be entered. Once the failure is repaired, the common cause failure no longer exists and Required Action D.4.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of the DG(s).

In the event the inoperable DG is restored to OPERABLE status prior to completing either D.4.1 or D.4.2, the problem investigation process will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition D.

According to Generic Letter 84-15 (Ref. 8), 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem

ACTIONS (continued)

as the inoperable DG.

D.5

In order to extend the Completion Time for an inoperable DG from 72 hours to 14 days, it is necessary to ensure the availability of the ESPS within 1 hour of entry into TS 3.8.1 LCO and every 12 hours thereafter.

Since Required Action D.5 only specifies “evaluate,” discovering the ESPS unavailable does not result in the Required Action being not met (i.e. the evaluation is performed). However, on discovery of an unavailable ESPS, the Completion Time for Required Action D.6 starts the 72 hour and/or 24 hour clock.

ESPS availability requires that:

1) The load test has been performed within 30 days of entry into the extended Completion Time. The Required Action evaluation is met with an administrative verification of this prior to testing; and

2) ESPS fuel tank level is verified locally to be ≥ 24 hour supply; and

3) ESPS supporting system parameters for starting and operating are verified to be within required limits for functional availability (e.g., battery state of charge).

The ESPS is not used to extend the Completion Time for more than one inoperable DG at any one time.

D.6

In accordance with Branch Technical Position 8-8 (Ref. 14), operation may continue in Condition D for a period that should not exceed 14 days, provided a supplemental AC power source is available.

In Condition D, the remaining OPERABLE DGs, unavailable ESPS, and offsite power circuits are adequate to supply electrical power to the Class 1E Distribution System. The 14 day 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.

If the ESPS is or becomes unavailable with an inoperable LCO 3.8.1.d DG, then action is required to restore the ESPS to available status or to restore the DG to OPERABLE status within 72 hours from discovery of

ACTIONS (continued)

unavailable ESPS. However, if the ESPS unavailability occurs at or sometime after 48 hours of continuous LCO 3.8.1.d DG inoperability, then the remaining time to restore the ESPS to available status or to restore the DG to OPERABLE status is limited to 24 hours.

The 72 hour and 24 hour Completion Times allow for an exception to the normal “time zero” for beginning the allowed outage time “clock.” The 72 hour Completion Time only begins on discovery that both:

a. An inoperable DG exists; and
b. ESPS is unavailable.

The 24 hour Completion Time only begins on discovery that:

a. An inoperable DG exists for ≥ 48 hours; and
b. ESPS is unavailable.

Therefore, when one LCO 3.8.1.d DG is inoperable due to either preplanned maintenance (preventive or corrective) or unplanned corrective maintenance work, the Completion Time can be extended from 72 hours to 14 days if ESPS is verified available for backup operation.

The fourth Completion Time for Required Action D.6 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 LCO 3.8.1.c or LCO 3.8.1.d. If Condition D is entered while, for instance, a LCO 3.8.1.c 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 17 days, since initial failure to meet LCO 3.8.1.c or LCO 3.8.1.d, to restore the DG. At this time, a LCO 3.8.1.c offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 20 days) allowed prior to complete restoration of LCO 3.8.1.c and LCO 3.8.1.d. The 17 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet LCO 3.8.1.c or LCO 3.8.1.d. This limit is considered reasonable for situations in which Conditions C and D are entered concurrently. The "AND" connector between the 14 day and 17 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

E.1 and E.2

Condition E is entered when both offsite circuits required by LCO 3.8.1.a are inoperable, or when the offsite circuit required by LCO 3.8.1.c and

ACTIONS (continued)

one offsite circuit required by LCO 3.8.1.a are concurrently inoperable. Condition E is also entered when two offsite circuits required by LCO 3.8.1.c are inoperable.

Required Action E.1, which applies when two 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. 7) 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 turbine driven auxiliary pumps, are not included in the list.

The Completion Time for Required Action E.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 E (two LCO 3.8.1.a offsite circuits inoperable or one LCO 3.8.1.a offsite circuit and one LCO 3.8.1.c offsite circuit inoperable or two LCO 3.8.1.c offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 7), operation may continue in Condition E 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 affect 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.

ACTIONS (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 that involve one or more DGs 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 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 unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time 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 or C, as applicable.

<u>F.1 and F.2</u>

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 F are modified by a Note to indicate that when Condition F 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 F to provide requirements for the loss of one offsite circuit and one DG, 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. 7), operation may continue in Condition F for a period that should not exceed 12 hours.

ACTIONS (continued)

In Condition F, 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 E (loss of two 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.

G.1

With two LCO 3.8.1.b DGs inoperable, there are no remaining standby AC sources to provide power to most of the ESF systems. With one LCO 3.8.1.b DG that provides power to the shared systems inoperable and one LCO 3.8.1.d DG that provides power to the shared systems inoperable, there are no remaining standby AC sources to the shared systems. Also, with two DGs required by LCO 3.8.1.d inoperable, there are no remaining standby AC sources to the two opposite unit NSWS pump(s) and at least one train of shared systems. 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 7, with both LCO 3.8.1.b DGs inoperable, with one LCO 3.8.1.b DG that provides power to the shared systems and one LCO 3.8.1.d DG that provides power to the shared systems inoperable, or with two DGs required by LCO 3.8.1.d inoperable, operation may continue for a period that should not exceed 2 hours.

H.1

The sequencer(s) is an essential support system to both the offsite circuit and the DG associated with a given ESF bus. Furthermore, the sequencer is on the primary success path for most major AC electrically

ACTIONS (continued)

powered safety systems powered from the associated ESF bus. Therefore, loss of an ESF bus sequencer affects every major ESF system in the train. When a sequencer is inoperable, its associated unit and train related offsite circuit and DG must also be declared inoperable and their corresponding Conditions must also be entered. The 12 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining sequencer OPERABILITY. This time period also ensures that the probability of an accident (requiring sequencer OPERABILITY) occurring during periods when the sequencer is inoperable is minimal.

I.1 and I.2

If any Required Action and associated Completion Time of Conditions A, C, F, G, or H are not met, the unit must be brought to a MODE in which the LCO does not apply. Furthermore, if any Required Action and associated Completion Time of Required Actions B.2, B.3, B.4.1, B.4.2, B.6, D.2, D.3, D.4.1, D.4.2, and D.6 are not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

J.1

Condition J corresponds to a level of degradation in which all redundancy in LCO 3.8.1.a and LCO 3.8.1.b AC electrical power supplies has been lost or in which all redundancy in LCO 3.8.1.c and LCO 3.8.1.d AC electrical power supplies has been lost. At this severely degraded level, any further losses in the AC electrical power system will cause a loss of function. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 9). 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), Regulatory Guide 1.108 (Ref. 10), and Regulatory Guide 1.137 (Ref. 11), as

SURVEILLANCE REQUIREMENTS (continued)

addressed in the UFSAR.

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 3950 V is 95% of the nominal 4160 V output voltage. This value allows for voltage drop to the terminals of 4000 V motors whose minimum operating voltage is specified as 90% or 3600 V. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating.

The specified maximum steady state output voltage of 4320 V ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V and 575 V motors is no more than the maximum rated operating voltages.

The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

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 unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note (Note 2 for SR 3.8.1.2) to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period and followed by a warmup period prior to loading.

SURVEILLANCE REQUIREMENTS (continued)

For the purposes of SR 3.8.1.2 and SR 3.8.1.7 testing, the DGs are started from standby conditions using a manual start, loss of offsite power signal, safety injection signal, or loss of offsite power coincident with a safety injection signal. 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 3, which is only applicable when such modified start procedures are recommended by the manufacturer.

SR 3.8.1.7 requires that the DG starts from standby conditions and achieves required voltage and frequency within 11 seconds. The 11 second start requirement supports the assumptions of the design basis LOCA analysis in the UFSAR, Chapter 15 (Ref. 5).

The 11 second start requirement is not applicable to SR 3.8.1.2 (see Note 3) when a modified start procedure as described above is used. If a modified start is not used, the 11 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 requires a 11 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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

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

SURVEILLANCE REQUIREMENTS (continued)

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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

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.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which 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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks 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

SURVEILLANCE REQUIREMENTS (continued)

provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. 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 system operates and transfers fuel oil from its associated storage tanks to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil valve is OPERABLE, and allows gravity feed of fuel oil to the day tank from underground storage tanks, to ensure the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for fuel transfer systems are OPERABLE.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

Transfer of each 4.16 kV ESF bus power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the capability of the alternate circuit distribution network to power the shutdown loads. The alternate circuit distribution network consists of an offsite power source through a 6.9 kV bus incoming breaker, its associated 6.9 kV bus tie breaker and the aligned 6.9/4.16 kV transformer to the essential bus. The requirement of this SR is the transfer from the normal offsite circuit to the alternate offsite circuit via the automatic and manual actuation of the 6.9 kV bus tie breaker and 6.9 kV bus incoming breakers upon loss of the normal offsite source that is being credited. The 6.9 kV bus tie breaker provides a means for each of the offsite circuits to act as a backup in the event power is not available from one of the circuits. The Catawba power system design, without the tie breaker, meets all GDC 17 requirements as well as all other standards to which Catawba is committed. If the tie breaker is incapable of closing manually or
automatically during its required MODE of applicability, then the

SURVEILLANCE REQUIREMENTS (continued)

Surveillance is not met and the normal offsite circuit that supplies that Class 1E ESF bus is inoperable and the applicable Condition shall be entered and the Required Actions shall be performed. Table B 3.8.1-1 identifies the offsite circuit affected by a non-functioning tie breaker.

The intent of the tie breaker is to provide an alternate means of power to a Class 1E ESF bus; this assumes there are two available offsite circuits. In the event an offsite circuit is lost for any reason, the function of the tie breaker is to close, and the offsite circuit that is supplying its normally connected Class 1E ESF bus is fully OPERABLE. With the tie breaker closed, then both Class 1E ESF buses are provided power from a single offsite circuit. The normally connected offsite circuit of the Class 1E ESF bus that is being supplied through the tie breaker shall be declared inoperable and the applicable Condition shall be entered and the Required Actions shall be performed. If the tie breaker does not close, then the associated Class 1E ESF bus will be supplied power from its associated DG. In this event, the associated offsite circuit is inoperable and the applicable Condition shall be entered and the Required Actions shall be performed. Capability of manually swapping to a standby transformer is not required to satisfy this SR. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

Table B 3.8.1-1 (page 1 of 1)
Relationship between Tie Breakers and Offsite Circuits

Tie Breaker	Description	Essential Load Center and Transformer	Affected Offsite Circuit
1TA-7	7kV Bus 1TA Tie Breaker	1ETA from 1ATC	1A
1TC-7	7kV Bus 1TC Tie Breaker	1ETA from SATA from Unit 1	
2TC-7	7kV Bus 2TC Tie Breaker	1ETA from SATA from Unit 2	
1TD-7	7kV Bus 1TD Tie Breaker	1ETB from 1ATD	1B
1TB-7	7kV Bus 1TB Tie Breaker	1ETB from SATB from Unit 1	
2TB-7	7kV Bus 2TB Tie Breaker	1ETB from SATB from Unit 2	
2TA-7	7kV Bus 2TA Tie Breaker	2ETA from 2ATC	2A
1TC-7	7kV Bus 1TC Tie Breaker	2ETA from SATA from Unit 1	
2TC-7	7kV Bus 2TC Tie Breaker	2ETA from SATA from Unit 2	
2TD-7	7kV Bus 2TD Tie Breaker	2ETB from 2ATD	2B
1TB-7	7kV Bus 1TB Tie Breaker	2ETB from SATB from Unit 1	
2TB-7	7kV Bus 2TB Tie Breaker	2ETB from SATB from Unit 2	

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

Each DG is provided with an engine overspeed trip to prevent damage to the engine. Recovery from the transient caused by the loss of a large load could cause diesel engine overspeed, which, if excessive, might result in a trip of the engine. This Surveillance demonstrates the DG load response characteristics and capability to reject the largest single load without exceeding predetermined voltage and frequency and while maintaining a specified margin to the overspeed trip. For this unit, the single load for each DG and its horsepower rating is as follows: Nuclear Service Water pump which is a 1000 H.P. motor. This Surveillance may be accomplished by:

a. Tripping the DG output breaker with the DG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or while solely supplying the bus; or

b. Tripping its associated single largest post-accident load with the DG solely supplying the bus.

As required by Regulatory Guide 1.9 (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. The value of 63 Hz has been selected for the frequency limit for the load rejection and it is a more conservative limit than required by Reference 3.

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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, the Note requires that, if synchronized to offsite power, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

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.

Although not representative of the design basis inductive loading that the DG would experience, a power factor of approximately unity (1.0) is used for testing. This power factor is chosen in accordance with manufacturer's recommendations to minimize DG overvoltage damage during testing.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.8.1.11

As required by Regulatory Guide 1.108 (Ref. 10), paragraph 2.a.(1), this Surveillance demonstrates the as designed operation of the standby power sources during loss of the offsite source. This test verifies all actions encountered from the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

The DG autostart time of 11 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.

SURVEILLANCE REQUIREMENTS (continued)

The requirement to verify the connection and power supply of the emergency bus and autoconnected 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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 is further amplified to allow portions of 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, at a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial 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 portions of the Surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (11 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.12.d ensures that the emergency bus remains energized from the offsite electrical power system on an ESF signal without loss of offsite power.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. This SR is modified by a Note. The reason for the Note is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations.

SR 3.8.1.13

This Surveillance demonstrates that DG non-emergency protective functions (e.g., high jacket water temperature) are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal. Non-emergency automatic trips are all automatic trips except:

a. Engine overspeed;
b. Generator differential current;
c. Low - low lube oil pressure; and
d. Voltage control overcurrent relay scheme.

The non-emergency 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. Currently, DG emergency automatic trips are tested periodically per the station periodic maintenance program.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Regulatory Guide 1.108 (Ref. 10), paragraph 2.a.(3), requires demonstration that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours. 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 $\leq$ 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.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This Surveillance is modified by a Note. The Note 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.

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 11 seconds. The 11 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. Note 1 ensures 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 an hour at full load conditions prior to performance of this Surveillance is based on

SURVEILLANCE REQUIREMENTS (continued)

manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.16

As required by Regulatory Guide 1.108 (Ref. 10), paragraph 2.a.(6), 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 standby operation when offsite power is restored. It also ensures that the autostart logic is reset to allow the DG to reload if a subsequent loss of offsite power occurs. The DG is considered to be in standby operation 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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 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, at 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, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

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 standby operation if a LOCA actuation signal is received during operation in the test mode. Standby 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 Regulatory Guide 1.9 (Ref. 3).

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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 is further amplified to allow portions of 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, at a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial 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 portions of the Surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

Under accident and loss of offsite power conditions loads are sequentially connected to the bus 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 interval tolerance in Table 8-6 of Reference 2 ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Table 8-6 of Reference 2 provides a summary of the automatic loading of ESF buses.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations for DGs. The reason for Note 2 is that the performance of the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, 3, or 4 is further amplified to

SURVEILLANCE REQUIREMENTS (continued)

allow portions of 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, at a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial 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 portions of the Surveillance are performed in MODE 1, 2, 3, or 4. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.20

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

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

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

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.

2. UFSAR, Chapter 8.

3. Regulatory Guide 1.9, Rev. 2, December 1979.

4. UFSAR, Chapter 6.

5. UFSAR, Chapter 15.

6. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).

7. Regulatory Guide 1.93, Rev. 0, December 1974.

8. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.

9. 10 CFR 50, Appendix A, GDC 18.

10. Regulatory Guide 1.108, Rev. 1, August 1977 (Supplement September 1977).

11. Regulatory Guide 1.137, Rev. 1, October 1979.

12. ASME, Boiler and Pressure Vessel Code, Section XI.

13. Response to a Request for Additional Information (RAI) concerning the June 5, 2006 License Amendment Request (LAR) Applicable to Technical Specification (TS) 3.8.1, “AC Sources-Operating,” Surveillance Requirement (SR) 3.8.1.13, (TAC NOS. MD3217, MD3218, MD3219, and MD3220), April 4, 2007.

14. Branch Technical Position 8-8, February 2012.

B 3.9 REFUELING OPERATIONS

B 3.9.5 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 and component cooling water through the RHR heat exchanger(s). 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.

The RHR System satisfies Criterion 4 of 10 CFR 50.36 (Ref. 2).

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.

BASES

LCO (continued)

This LCO is modified by two Notes. Note 1 permits the RHR pumps to be removed from operation for ≤ 15 minutes when switching from one train to another. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and the core outlet temperature is maintained > 10 degrees F below saturation temperature. Note 1 also 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 the other loop is OPERABLE and in operation. Prior to declaring the loop inoperable, consideration should be given to the existing plant configuration. This consideration should include that the core time to boil is short, there is no draining operation to further reduce RCS water level, and that the capability exists to inject borated water into the reactor vessel. This permits surveillance tests to be performed on the inoperable loop during a time when these tests are safe and possible.

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. An OPERABLE RHR heat exchanger includes an available heat sink comprised of the necessary component cooling support function to meet RHR heat load requirements. Componenet cooling support for RHR may be provided by a cross connected alignment where opposite train component cooling pumps can be aligned through a single component cooling heat exchanger. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs. The operability of the operating RHR train and the supporting heat sink is dependent on the ability to maintain the desired RCS temperature. If not in its normal RHR alignment from the RCS hot leg and returning to the RCS cold legs, the required RHR loop is OPERABLE provided the system may be placed in service from the control room, or may be placed in service in a short period of time by actions outside the control room and there are no restraints to placing the equipment in service. Management of gas voids is important to RHR System OPERABILITY.

Both RHR pumps may be aligned to the Refueling Water Storage Tank to support filling the refueling cavity or for performance of required testing.

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 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level."

BASES

ACTIONS

A.1 and A.2

If less than the required number of RHR loops are OPERABLE, action 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 3.9.4, 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. Suspending positive reactivity additions that could result in failure to meet the minimum boron concentration limit is required to assure continued safe operation. Introduction of coolant inventory must be from sources that have a boron concentration greater than that which would be required in the RCS for minimum refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation.

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, B.4, B.5.1, and B.5.2

If no RHR loop is in operation, the following actions must be taken:

a. The containment equipment hatch must be closed and secured with four bolts.
b. One door in each air lock must be closed, and
c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere must be either closed by a manual or automatic isolation valve, blind flange, or equivalent, or verified to be capable of being closed on a high radiation signal.

With RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Performing the actions described above ensures that all containment penetrations are either closed or can be closed so that the dose limits are not exceeded.

BASES

ACTIONS (continued)

The Completion Time of 4 hours allows fixing of most RHR problems and 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 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, prevent vortexing in the suction of the RHR pumps, and to prevent thermal and boron stratification in the core. The RCS temperature is determined to ensure the appropriate decay heat removal is maintained. 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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.9.5.2

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 Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program.

SR 3.9.5.3

RHR System piping and components have the potential to develop voids and pockets of entrained gases. Preventing and managing gas intrusion and accumulation is necessary for proper operation of the RHR loops and may also prevent water hammer, pump cavitation, and pumping of noncondensible gas into the reactor vessel.

Selection of RHR System locations susceptible to gas accumulation is based on a review of system design information, including piping and instrumentation drawings, isometric drawings, plan and elevation drawings, and calculations. The design review is supplemented by system walk downs to validate the system high points and to confirm the location and orientation of important components that can become sources of gas or could otherwise cause gas to be trapped or difficult to remove during system maintenance or restoration. Susceptible locations depend on plant and system configuration, such as stand-by versus

BASES

SURVEILLANCE REQUIREMENTS (continued)

operating conditions.

The RHR System is OPERABLE when it is sufficiently filled with water. Acceptance criteria are established for the volume of accumulated gas at susceptible locations. If accumulated gas is discovered that exceeds the acceptance criteria for the susceptible location (or the volume of accumulated gas at one or more susceptible locations exceeds an acceptance criteria for gas volume at the suction or discharge of a pump), the Surveillance is not met. If it is determined by subsequent evaluation that the RHR System is not rendered inoperable by the accumulated gas (i.e., the system is sufficiently filled with water), the Surveillance may be declared met. Accumulated gas should be eliminated or brought within the acceptance criteria limits.

RHR System locations susceptible to gas accumulation are monitored and, if gas is found, the gas volume is compared to the acceptance criteria for the location. Susceptible locations in the same system flow path which are subject to the same gas intrusion mechanisms may be verified by monitoring a representative sub-set of susceptible locations. Monitoring may not be practical for locations that are inaccessible due to radiological or environmental conditions, the plant configuration, or personnel safety. For these locations alternative methods (e.g., operating parameters, remote monitoring) may be used to monitor the susceptible location. Monitoring is not required for susceptible locations where the maximum potential accumulated gas void volume has been evaluated and determined to not challenge system OPERABILITY. The accuracy of the method used for monitoring the susceptible locations and trending of the results should be sufficient to assure system OPERABILITY during the Surveillance interval.

The Surveillance Frequency is based on operating experience, equipment reliability, and plant risk and is controlled under the Surveillance Frequency Control Program. The Surveillance Frequency may vary by location susceptible to gas accumulation.

REFERENCES

1. UFSAR, Section 5.5.7.
2. 10 CFR 50.36, Technical Specifications, (c)(2)(ii).

Enclosure 5

Catawba Nuclear Station
Selected Licensee Commitments (SLC) Manual Changes

Removal and insertion instructions for Catawba Nuclear Station Selected Licensee Commitments (SLC) Manual with the attached revised page(s) for the period of April 2, 2020 thru October 4, 2021. The revised page(s) are identified by Section number and contains marginal lines indicating the areas of change.

REMOVE THESE PAGES		**INSERT THESE PAGES**
	LIST OF EFFECTIVE SECTIONS	
Pages 1-5 Revision 87		Pages 1-5 Revision 102
	TAB 16.5	
16.5-1 Revision 5		16.5-1 Revision 7
16.5-9 Revision 2		16.5-9 Deleted
	TAB 16.6	
16.6-5 Revision 2		16.6-5 Revision 3
	TAB 16.7	
16.7-5 Revision 2		16.7-5 Revision 5
16.7-9 Revision 11		16.7-9 Revision 13
16.7-10 Revision 8		16.7-10 Revision 9
	TAB 16.8	
16.8-1 Revision 6		16.8-1 Revision 7
	TAB 16.9	
16.9-18 Revision 0		16.9-18 Deleted
	TAB 16.10	
		16.10-4 (NEW) Revision 0

TAB 16.10 (continued)

	16.10-5 (NEW) Revision 1

TAB 16.11

16.11-2 Revision 4	16.11-2 Revision 6
16.11-7 Revision 10	16.11-7 Revision 12

TAB 16.13

16.13-4 Revision 2	16.13-4 Revision 4

LIST OF EFFECTIVE SECTIONS

SECTION	REVISION NUMBER	REVISION DATE
TABLE OF CONTENTS	15	05/10/16
16.1	1	08/27/08
16.2	2	08/21/09
16.3	1	08/21/09
16.5-1	7	03/30/21
16.5-2	Deleted	
16.5-3	2	09/19/19
16.5-4	0	10/09/02
16.5-5	1	01/28/10
16.5-6	1	08/21/09
16.5-7	2	02/06/15
16.5-8	Deleted	
16.5-9	Deleted	03/02/21
16.5-10	Deleted	
16.6-1	0	10/09/02
16.6-2	Deleted	
16.6-3	1	08/21/09
16.6-4	2	11/21/19
16.6-5	3	07/07/20
16.7-1	1	08/21/09
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16.7-3	5	11/21/19
16.7-4	2	08/21/09
16.7-5	5	04/20/21

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16.7-7	1	08/21/09
16.7-8	2	08/21/09
16.7-9	13	09/14/21
16.7-10	9	04/23/20
16.7-11	1	08/21/09
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16.7-13	3	06/10/16
16.7-14	1	08/21/09
16.7-15	1	08/21/09
16.7-16	0	06/08/09
16.7-17	0	02/10/15
16.7-18	0	05/10/16
16.8-1	7	06/01/20
16.8-2	3	12/18/19
16.8-3	1	10/24/06
16.8-4	2	11/05/07
16.8-5	3	08/21/09
16.9-1	10	01/29/19
16.9-2	6	08/03/17
16.9-3	5	07/03/18
16.9-4	5	09/11/17
16.9-5	11	10/08/19
16.9-6	12	07/03/18

SECTION	REVISION NUMBER	REVISION DATE
16.9-7	4	08/21/09
16.9-8	5	08/21/09
16.9-9	3	08/21/09
16.9-10	5	08/21/09
16.9-11	3	08/21/09
16.9-12	3	02/10/15
16.9-13	4	09/27/16
16.9-14	1	09/25/06
16.9-15	2	08/21/09
16.9-16	2	08/21/09
16.9-17	0	10/09/02
16.9-18	Deleted	
16.9-19	3	02/20/12
16.9-20	0	10/09/02
16.9-21	1	10/13/16
16.9-22	1	08/21/09
16.9-23	5	08/03/17
16.9-24	2	10/24/06
16.9-25	2	08/21/09
16.9-26	1	11/15/18
16.10-1	1	08/21/09
16.10-2	1	10/24/06
16.10-3	1	08/21/09
16.10-4	0	08/04/20

LIST OF EFFECTIVE SECTIONS

16.5 REACTOR COOLANT SYSTEM

16.5-1 Reduced Inventory and Mid-Loop Operation with Irradiated Fuel in the Core

COMMITMENT

Two independent trains of reactor coolant system level instruments are required. These instruments shall have independent transmitters and shall not include the reactor coolant system sightglass (NCLG-6450) or tygon tubing.

AND

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

1. Final disconnection of the last two core exit thermocouples shall occur no sooner than 2 hours prior to reactor vessel head removal.

2. Reconnection of at least two thermocouples shall occur within 2 hours after reinstalling the reactor vessel head.

3. The total time without thermocouple indication shall not exceed 12 hours.

Whenever the reactor vessel head is installed, two core exit thermocouples shall be maintained operating with temporary high alarms set at 140°F and monitored.

AND

--NOTE---

The number of open containment penetrations shall be limited such that the penetrations can be closed prior to the onset of core boiling upon loss of residual heat removal.

Containment closure shall be established. Containment closure is verified by the performance of PT/1/(2)/A/4200/002C&I, Containment Closure Verification, with penetrations not verified acceptable, administratively controlled per OP/0/A/6100/014, Penetration Control For Modes 5 and 6.

AND

The reactor has been subcritical for at least 7 days or Engineering has provided a required subcritical time based on plant operating history and actual reduced reactor coolant system level.

(continued)

COMMITMENT (continued)

<u>AND</u>

Operation in a mid-loop condition shall only occur during low decay heat conditions (after refueling).

<u>AND</u>

One of the following (either A. or B. or C. below):

A. Four power sources (two offsite sources and two diesel generators) and two independent makeup paths of borated water (one centrifugal charging pump or one safety injection pump as required per SLC 16.9-7 and SLC 16.9-9 and one additional centrifugal charging pump or safety injection pump on the opposite train as the first required makeup path) shall be available.

<u>OR</u>

B. Three power sources (two offsite sources and one diesel generator or one offsite source and two diesel generators), a hot leg vent path established (the reactor vessel head removed or no hot leg nozzle dam installed coupled with the removal of the hot or the cold leg diaphragm and manway on the associated loop), and two independent makeup paths of borated water (one centrifugal charging pump or one safety injection pump as required per SLC 16.9-7 and SLC 16.9-9 and one of the following gravity flow paths: 1) refueling water storage tank through ND-33 to the cold legs via NI-173A or NI-178B, 2) refueling water storage tank through the residual heat removal suction lines to the hot legs, 3) refueling water storage tank through ND-33 to the hot legs via NI-183B) shall be available.

<u>OR</u>

C. Three power sources (two offsite sources and one diesel generator or one offsite source and two diesel generators), and two independent makeup paths of borated water, 1) one centrifugal charging pump or one safety injection pump as required per SLC 16.9-7 and SLC 16.9-9 <u>AND</u> 2) a gravity flow path from the refueling water storage tank through ND-33 to the cold legs via NI-173A or NI-178B shall be available. Additional conditions are, 1) the reactor has been refueled and shutdown for at least 10 days, 2) pressurizer is vented by at least one PZR

(continued)

COMMITMENT (continued)

Safety Valve removed and open to containment with an FME cover consistent with that described in CNC-1552.08-00-0510, and 3) FWST level is ≥ 86.0% (401.03 inches).

AND

The Reactor Coolant System (RCS) shall be properly vented when SG nozzle dams are in use or the RCS cold legs are open >1in^2. The vent may be satisfied by the following:

1. On the vented loop, no hot leg nozzle dam installed
   AND
   Removal of either of the following:
   a. A hot leg diaphragm and manway
      OR
   b. A cold leg diaphragm and manway

OR

2. Rector vessel head is removed.

OR

-----------------------------------NOTE-------------------------------
Vent path 3 is restricted to the nozzle dams analyzed in Reference 14 for Unit 1 and Reference 15 for Unit 2.
----

3. All three Pressurizer Code Safety Valves have been removed. This option does NOT apply if there is a cold leg opening >1in^2 (including potential openings that could develop when pressurization occurs).

   Option 3 may only be used when all of the following conditions are satisfied:
   1. The reactor has been shutdown for at least 12 days.
   2. The reactor has been refueled.

APPLICABILITY: Whenever irradiated fuel is in the reactor vessel and reactor coolant system wide range level is ≤ 16%.

REMEDIAL ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more COMMITMENT(S) not met.	A.1 Initiate action to restore compliance with COMMITMENT(S). <u>AND</u> A.2 Contact station management for additional guidance.	Immediately Immediately
B. Primary method of monitoring core exit thermocouples unavailable.	B.1 Monitor and record thermocouple temperatures on the Incore Instrument Panel.	Once per 15 minutes

TESTING REQUIREMENTS None

BASES

Generic Letter 88-17 and NUREG-1410 involve concerns associated with a loss of residual heat removal. Numerous events have occurred in the industry that resulted in a loss of residual heat removal during reduced inventory operation. This is of great concern due to the potential for substantial core damage occurring in a relatively short time period.

The basis for the requirement for the reactor to be subcritical for 7 days is to ensure 2.5 hours until the core is uncovered following a loss of decay heat removal when at mid-loop operation (Refs. 10, 11).

The vent path is provided to address Expeditious Action (7) of Generic Letter 88-17. The vent path is provided to assure that the nozzle dams are not dislodged due to pressurization that could result on a loss of decay heat removal event resulting in core boiling. In the absence of a sufficient vent path, pressurization following a loss of residual heat removal in combination with cold leg openings could allow water to be ejected from the vessel and lead to rapid core uncovery.

Per Reference 13, one Reactor Coolant Pump uncoupled from its motor does not introduce a cold leg opening $\geq 1in^2$.

This Selected Licensee Commitment depicts those commitments which are extremely important to nuclear safety, however, are not presently covered by Technical Specifications.

REFERENCES

1. Generic Letter 88-17, “Loss of Decay Heat Removal.”

2. NUREG-1410, “Loss of Vital AC Power and Residual Heat Removal during Mid-Loop Operation at Vogtle.”

3. AD-WC-CNS-0420, “Catawba Nuclear Station Shutdown Risk Management.”

4. OP/1(2)/A/6150/06, “Draining the Reactor Coolant System.”

5. Catawba Nuclear Station Technical Specifications.

6. Catawba Design Basis Specification for the Reactor Coolant (NC) System.

7. Oconee Nuclear Station Selected Licensee Commitment 16.5.3.

8. Work Processes Manual, Sections 602, “Outage Management,” and 603, “Unit Trip Forced Outage Management.”

9. Catawba Nuclear Station responses to Generic Letter 88-17 dated January 3, 1989 and February 2, 1989.

10. Design Study CNDS-0242, “Catawba and McGuire Nuclear Stations, Shutdown by Decay Heat Level Before Mid-Loop Operation.”

11. DPC-1552-08-00-0023, “Loss of Decay Heat Removal (G.L. 88-17).”

12. CNC-1552.08-00-0510, "Loss of Decay Heat Removal - Gravity Drain Flow Evaluation."

13. EC EVAL 417274, Evaluation of Cold Leg Opening Through a Reactor Coolant Pump.

14. CNC-1201.37-00-0059, “Nozzle Dam Design Report.”

15. CNC-1223.03-00-0039, “Engineering Analysis for Unit 2 Type WR-2 Steam Generator Nozzle Dams” (CNM 2201.01-0960), and/or CNC-1223.03-00-0042, “Unit 2 Design and Seismic Report for Type WR-2B Steam Generator Nozzle Dam” (CNM 2201.01-0990).

16. DPC-1552.08-00-0017, “Analysis of Potential NC System Vent Paths During Nozzle Seal Dam Installation and Use.”

REFERENCES (continued)

17. NUREG-1449, "Shutdown and Low-Power Operation at Commercial Nuclear Power Plants in the United States."

18. NRC letter to Hal Tucker, "Comments on Expeditious Action and Notice of Audit on Generic Letter 88-17, McGuire and Catawba Nuclear Stations, Units 1 and 2," dated May 17, 1989.

19. DPC-1552.08-00-0323, "GOTHIC Analysis of NC System Vent Paths During Steam Generator Nozzle Dam Use."

16.6 ENGINEERED SAFETY FEATURES

16.6-5 Residual Heat Removal/Containment Spray Sump Pump Interlock

NOTES:

1. The ND/NS sump level switches provide input to the ND/NS sump High-High Level annunciator. These level switches are powered from the associated ND/NS sump pump motor supply circuit.
2. To be considered functional the level indication and sump pump must be supplied from an essential buss with an operable onsite power source.

COMMITMENT

The residual heat removal/containment spray sump pump interlock shall be FUNCTIONAL. This feature requires the following:

- Two of four functional ND/NS sump pump level switches.
    - 0WLLS5060 (Associated with pump 1A)
    - 0WLLS5080 (Associated with pump 1B)
    - 0WLLS5070 (Associated with pump 2A)
    - 0WLLS5090 (Associated with pump 2B)

    AND

- Annunciator Panel 1AD-10 C/2, ND & NS Rooms Sump Level HI-HI, Functional

At least two ND/NS sump pumps should remain Functional. The condition of less than two (2) Functional ND/NS pumps shall be minimized.

APPLICABILITY: MODES 1, 2, 3, and 4 on either Unit 1 or Unit 2.

REMEDIAL ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. COMMITMENT not met.	A.1 Initiate action to implement alternate means of fulfilling the interlock function to detect leakage from ECCS components in the event of a Safety Injection.	Immediately

TESTING REQUIREMENTS

TEST		FREQUENCY
TR 16.6-5-1	Perform SLAVE RELAY TEST of the interlock auxiliary relay.	18 months
TR 16.6-5-2	Perform TADOT of the ND/NS sump level switches.	3 years
TR 16.6-5-3	Verify each sump pump's flow rate is greater than or equal to the required flow rate.	In Accordance with the INSERVICE TESTING PROGRAM

BASES

The basis for the residual heat removal/containment spray sump pump interlock is to alert the operator to potential Emergency Core Cooling System leakage. The interlock will inhibit operation of the sump pumps at the high level setpoint, subsequent to a safety injection signal on either unit. When the sump inventory increases to the high-high level setpoint, an alarm in the control room alerts the operator to the increasing sump level and the sump pumps will start. In the event that the COMMITMENT is not met, the REMEDIAL ACTION ensures that the function of the interlock can be fulfilled using alternate means. The REMEDIAL ACTION purpose is to promptly detect leakage in the event of an accident to allow isolation of a passive failure of an ECCS or NS pump seal within 30 minutes.

The interlock utilizes an auxiliary relay (K639); however, this particular relay does not perform any actual Engineered Safety Features function. The specified TESTING REQUIREMENT ensures that the interlock remains capable of performing its intended function. The 18-month Frequency is based on the known reliability of relays of this type.

The TADOT of the sump level switches assures the annunciator 1AD-10 C-2 is functional.

The In Service Test (IST) of the ND/NS sump pumps assures that the sump pumps and associated sump check valves are functional.

A license basis review documented in reference 3, determined that the Auxiliary Building 522 elevation has sufficient capacity to protect the NS and ECCS safety functions in the event of a passive failure of ECCS or NS piping or pump seal following transfer to cold leg recirculation assuming the leakage is promptly detected and isolated without the benefit of the ND/NS sump

BASES (continued)

pumps. However Functional sump pumps aid in mitigation of flooding of the 522 elevation.

TR 16.6-5-1 verifies the ND/NS interlock from SSPS is functional.
TR 16.6-5-2 verifies the control room annunciator is functional.
TR 16.6-5-3 verifies the ND/NS Sump Pump starts on High level and delivers >100 gpm nominal flow in accordance with Reference 1.b and reference 3 and 4. The In-Service Testing also monitors component vibration and forward and reverse flow through check valves in the discharge flowpath.

REFERENCES

1. Catawba Updated Final Safety Analysis Report
   a. Section 11.2.2.2.4.3, Containment Spray and Residual Heat Removal Pump Room Sumps
   b. Section 11.2.2.2.5.6, Containment Spray and Residual Heat Removal Pump Room Sump Pumps
   c. Section 7.6.6, Liquid Radwaste System
   d. Section 10.4.9, Auxiliary Feedwater System
   e. Section 6.3.2.5, System Reliability (ECCS)

2. WCAP-13877, Revision 1-P-A, “Reliability Assessment of Westinghouse Type AR Relays Used as SSPS Slave Relays,” December 1999.

3. CNC-1206.03-00-0001, Flood Levels For Structures outside the Reactor Building, Appendix E.

4. CNTC-1(2)565-WL-P004, ND & NS Room Sump Pumps.

16.7 INSTRUMENTATION

16.7-5 Turbine Overspeed Protection

COMMITMENT At least one Turbine Overspeed Protection System shall be FUNCTIONAL.

APPLICABILITY: MODES 1, 2, and 3.

REMEDIAL ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One stop valve or one control valve per high pressure turbine steam line non-functional.	A.1 Restore non-functional valve(s) to FUNCTIONAL status.	72 hours
	<u>OR</u>	
	A.2 Close at least one valve in affected steam line(s).	78 hours
	<u>OR</u>	
	A.3 Isolate the turbine from the steam supply.	78 hours
B. One intermediate stop valve or one intercept valve per low pressure turbine steam line non-functional.	B.1 Restore non-functional valve(s) to FUNCTIONAL status.	72 hours
	<u>OR</u>	
	B.2 Close at least one valve in affected steam line(s).	78 hours
	<u>OR</u>	
	B.3 Isolate the turbine from the steam supply.	78 hours

(continued)

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Turbine Overspeed Protection System non-functional for reasons other than Condition A or B.	C.1 Isolate the turbine from the steam supply.	6 hours

TESTING REQUIREMENTS

TEST		FREQUENCY
TR 16.7-5-1	--------------------------------NOTES-------------------------------- 1. This TR shall be performed in MODE 1 or in MODE 2 with the turbine operating. 2. Not required to be performed until 24 hours after each valve is opened. -- Cycle while performing a direct observation of the four high pressure turbine stop valves, six low pressure turbine intermediate stop valves, six low pressure turbine intercept valves, and four high pressure turbine control valves, through one complete cycle from the running position.	4 months
TR 16.7-5-2	Perform CHANNEL CALIBRATION.	18 months

(continued)

	TEST	FREQUENCY
TR 16.7-5-3	Disassemble at least one each of the four high pressure turbine stop valves, six low pressure turbine intermediate stop valves, six low pressure turbine intercept valves, and four high pressure turbine control valves, and perform a visual and surface inspection of valve seats, disks, and stems, and verify no unacceptable flaws or corrosion.	54 months

BASES

This COMMITMENT is provided to ensure that the Turbine Overspeed Protection instrumentation and the turbine speed control valves are FUNCTIONAL and will protect the turbine from excessive overspeed. Protection from turbine excessive overspeed is required since excessive overspeed of the turbine could generate potentially damaging missiles which could impact and damage safety related components, equipment, or structures.

The term "Isolate the turbine from the steam supply" used in Required Actions A.3, B.3, and C.1 can be met in several ways. These include:
Maintaining the turbine in a tripped condition; or
Hydraulically gagging all four main stop valves closed; or
Hydraulically gagging all four main control valves closed; or
Closing the main steam isolation valves and main steam isolation valve bypass valves.

REFERENCES

None

16.7 INSTRUMENTATION

16.7-9 Standby Shutdown System (SSS)

COMMITMENT The SSS shall be FUNCTIONAL.

APPLICABILITY: MODES 1, 2, and 3.

REMEDIAL ACTIONS

---NOTE---
SLC 16.2.3 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SSS non-functional.	A.1 Restore SSS to FUNCTIONAL status.	7 days
B. Total accumulative LEAKAGE from unidentified LEAKAGE, identified LEAKAGE, and reactor coolant pump seal LEAKAGE > 20 gpm.	B.1 Declare the standby makeup pump non-functional and enter Condition A.	Immediately
C. A required cell in a 24-Volt battery bank is < 1.36 volts on float charge.	C.1 Enter Condition A.	Immediately
D. Required Action and associated Completion Time of Condition A not met.	D.1 Prepare and submit a Special Report to the NRC outlining the extent of repairs required, schedule for completing repairs, and basis for continued operation.	14 days

TESTING REQUIREMENTS

	TEST	FREQUENCY
TR 16.7-9-1	Verify that the electrolyte level of each SSS diesel starting 24-Volt battery is ≥ the low mark and ≤ the high mark.	7 days
TR 16.7-9-2	Verify that the overall SSS diesel starting 24-Volt battery voltage is ≥ 24 volts on float charge.	7 days
TR 16.7-9-3	Verify that the requirements of SLC 16.9-21 are met and the boron concentration in the storage pool is ≥ the minimum specified in the COLR.	7 days
TR 16.7-9-4	Verify the fuel level in the SSS diesel generator fuel storage tank is ≥ 67 inches.	31 days
TR 16.7-9-5	Verify the SSS diesel generator starts from ambient conditions and operates for ≥ 30 minutes at ≥ 700 kW.	31 days
TR 16.7-9-6	Verify that the electrolyte level of each SSS 250/125-Volt battery is above the plates.	31 days
TR 16.7-9-7	Verify the total SSS 250/125-Volt battery terminal voltage is ≥ 258/129 volts on float charge.	31 days
TR 16.7-9-8	Perform CHANNEL CHECK of each SSS instrumentation device.	31 days
TR 16.7-9-9	Verify the fuel oil properties of new and stored fuel oil for the SSS diesel generator 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
TR 16.7-9-10	Verify that the individual battery cell voltage of the required cells in the SSS diesel starting 24-Volt battery is ≥ 1.36 volts on float charge.	92 days

(continued)

TESTING REQUIREMENTS (continued)

TEST		FREQUENCY
TR 16.7-9-11	Verify that the Standby Makeup Pump's developed head at the test flow point is $\geq$ the required developed head, in accordance with the Inservice Testing Program.	92 days
TR 16.7-9-12	Verify that the specific gravity of the SSS 250/125-Volt battery is appropriate for continued service of the battery.	92 days
TR 16.7-9-13	Subject the SSS diesel generator to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for the class of service.	18 months
TR 16.7-9-14	Verify that the SSS diesel starting 24-Volt batteries, cell plates, and battery racks show no visual indication of physical damage or abnormal deterioration.	18 months
TR 16.7-9-15	Verify that the SSS diesel starting 24-Volt battery-to-battery and terminal connections are clean, tight, and free of corrosion.	18 months
TR 16.7-9-16	Verify that the SSS 250/125-Volt batteries, cell plates, and battery racks show no visual indications of physical damage or abnormal deterioration.	18 months
TR 16.7-9-17	Verify that the SSS 250/125-Volt battery-to-battery and terminal connections are clean, tight, free of corrosion, and coated with anti-corrosion material.	18 months
TR 16.7-9-18	Verify that the steam turbine driven auxiliary feedwater pump and controls from the Standby Shutdown Facility function as designed from the SSS.	18 months
TR 16.7-9-19	Perform CHANNEL CALIBRATION of each SSS instrumentation device.	18 months

(continued)

TESTING REQUIREMENTS (continued)

TEST		FREQUENCY
TR 16.7-9-20	Verify proper installation of pressurizer insulation.	18 months
TR 16.7-9-21	Verify pressurizer heaters powered from the SSS have a capacity of $\geq$ 63.5 kW measured at motor control center SMXG.	18 months
TR 16.7-9-22	Verify flowpath from the reactor vessel head through the valves powered from the SSS is unobstructed.	18 months

BASES

The SSS is designed to mitigate the consequences of certain postulated fire, security, and station blackout incidents by providing capability to maintain MODE 3 conditions and by controlling and monitoring vital systems from locations external to the main control room. This capability is consistent with the requirements of 10 CFR Part 50.48(c).

When the SSS is under Condition A and it is anticipated that Condition D will be utilized, establish the bases for continued operation (including any supporting actions) prior to entering Condition D. Risks associated with the continued operation under Condition D are evaluated and managed through existing processes and procedures. These risk contributors, risk insights, risk-informed information, and/or risk mitigation actions assessed and managed during periods when Condition D is applied, are to be included in the 14-day special report.

The TESTING REQUIREMENTS ensure that the SSS systems and components are capable of performing their intended functions. The required level in the SSS diesel generator fuel storage tank ensures sufficient fuel for 72 hours uninterrupted operation. It is assumed that, within 72 hours, either offsite power can be restored or additional fuel can be added to the storage tank.

Although the standby makeup pump is not nuclear safety related and was not designed according to ASME Code requirements, it is tested quarterly to ensure its FUNCTIONALITY. The TESTING REQUIREMENT concerning the standby makeup pump water supply ensures that an adequate water volume is available to supply the pump continuously for 72 hours.

Total accumulative LEAKAGE is calculated in the NC System Leakage Calculation procedure as identified + unidentified + seal leakoff (References 2 and 3). The REMEDIAL ACTION limit of 20 gpm total accumulative LEAKAGE provides additional margin to allow for

BASES (continued)

instrument inaccuracy, and for the predicted increase in seal leakoff rate due to heatup of the reactor coolant pump seal injection water supply temperature following the SSS event (due to spent fuel pool heatup). Following the increase in seal injection temperature, the standby makeup pump flow of 26 gpm is sufficient to provide in excess of this total accumulative LEAKAGE, thereby assuring that reactor coolant system inventory is maintained at MODE 3 conditions. The supporting evaluation is provided in CNC-1223.04-00-0072 (Ref. 4).

A visual inspection of the diesel starting 24-volt batteries, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance. Since the battery cell jars are not transparent, a direct visual inspection of the cell plates cannot be performed. Instead, the cell plates are inspected for physical damage and abnormal deterioration by: 1) visually inspecting the jar sides of each cell for excessive bowing and/or deformation, and 2) visually inspecting the electrolyte of each cell for abnormal appearance.

Verifying individual cell voltage while on float charge for the SSS diesel starting 24-Volt batteries ensures that each cell is capable of supporting its 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 battery cell) in a fully charged state. The battery cell voltage limit of 1.36 volts is consistent with the nominal design voltage of the battery and is based on the manufacturer's recommended minimum float charge voltage for a fully charged cell with adequate capacity. The 24-Volt starting battery is designed with two battery banks, each battery bank contains 20 individual battery cells. The 24-Volt starting battery has sufficient capacity margin to maintain SSS diesel starting functionality with one cell in each battery bank to be fully degraded with a voltage < 1.36 volts. The 24-Volt starting battery is required to have 19 individual battery cells per battery bank to maintain SSS diesel starting functionality with sufficient capacity margin. The battery sizing calculation accounts for one degraded cell in each battery bank by assuming the degraded cells undergo a worst case polarity reversal during SSS diesel starting. The supporting evaluation is provided in CNC-1381.06-00-0056 (Ref.12).

Verification of proper installation of pressurizer insulation ensures that pressurizer heat losses during an SSS event do not exceed the capacity of the pressurizer heaters powered from the SSS.

Testing of the pressurizer heater capacity ensures the full capacity of the heaters is available to maintain a steam bubble in the pressurizer during an SSS event. The acceptance criterion includes an allowance for the voltage drop in the power cables between the SSS and the pressurizer and measurement uncertainty.

BASES (continued)

Testing of the flowpath from the reactor vessel head to the pressurizer relief tank ensures sufficient flow capacity for reactor coolant inventory control during an SSS event.

REFERENCES

1. Letter from NRC to Gary R. Peterson, Duke, Issuance of Improved Technical Specifications Amendments for Catawba, September 30, 1998.

2. PT/1(2)/A/4150/001D, NC System Leakage Calculation.

3. PT/1(2)/A/4150/001I, Manual NC Leakage Calculation.

4. CNC-1223.04-00-0072, Reactor Coolant Pumps No. 1 Seal Leakoff Annunciator Alarm Setpoint for Unit 1 and Unit 2.

5. CNS-1560.SS-00-0001, Design Basis Specification for the Standby Shutdown Facility.

6. Catawba Technical Specification Amendments 206/200, July 10, 2003.

7. Catawba UFSAR, Section 18.2.4.

8. Catawba License Renewal Commitments, CNS-1274.00-00-0016, Section 4.5.

9. CNC-1223.03-00-0033, Determination of Pressurizer Heater Capacity Powered from the SSF Diesel.

10. Catawba Nuclear Station 10 CFR 50.48(c) Fire Protection Safety Evaluation (SE).

11. 10 CFR 50.48(c), Fire Protection.

12. CNC-1381.06-00-0056, SSF Diesel Generator Battery Sizing Calculation.

16.7 INSTRUMENTATION

16.7-10 Radiation Monitoring for Plant Operations

COMMITMENT The radiation monitoring instrumentation channels for plant operations shown in Table 16.7-10-1 shall be FUNCTIONAL.

APPLICABILITY: As shown in Table 16.7-10-1.

REMEDIAL ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more radiation monitoring channels Alarm/Trip setpoint for plant operations exceeding the value shown in Table 16.7-10-1.	A.1 Adjust the setpoint to within the limit. OR A.2 Declare the channel non-functional.	4 hours 4 hours

(continued)

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One Containment Atmosphere – High Gaseous Radioactivity (EMF-39 – Low Range) channel non-functional.	B.1 -------------NOTE-------------- In order to utilize Required Action B.1, the following conditions must be satisfied: 1. The affected unit is in MODES 5 or 6. 2. EMF-36 is FUNCTIONAL and in service for the affected unit. 3. The Reactor Coolant System for the affected unit has been vented. 4. Either the reactor vessel head is in place (bolts are not required), or if it is not in place, the lifting of heavy loads over the reactor vessel and the movement of irradiated fuel assemblies within containment have been suspended. ------------------------------------	
	Restore the non-functional channel to FUNCTIONAL status.	12 hours

(continued)

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition B not met. OR Required Action B.1 not utilized.	C.1 Close the Containment Purge Exhaust System (CPES) valves.	Immediately
D. One Control Room Air Intake – Radiation Level – High Gaseous Radioactivity (EMF-43A & B – Low Range) channel non-functional in one or both control room intakes.	D.1 Initiate action to restore non-functional channel(s) to FUNCTIONAL status. AND D.2 Ensure that one Control Room Area Ventilation System (CRAVS) train is in operation.	Immediately 1 hour
E. One Fuel Storage Pool Area – Radiation Level (1EMF-15, 2EMF-4) channel non-functional.	E.1 Provide a portable continuous monitor with the same Alarm Setpoint in the fuel storage pool area. AND E.2.1 Restore non-functional monitor to FUNCTIONAL status. OR E.2.2 Suspend all operations involving fuel movement in the fuel building.	Immediately 30 days 30 days

(continued)

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One Fuel Storage Pool Area – High Gaseous Radioactivity (EMF-42) channel non-functional.	F.1.1 Initiate action to restore non-functional channel to FUNCTIONAL status.	Immediately
	AND	
	F.1.2 --------------NOTE------------- Only applicable during fuel handling operations in the fuel building. ------------------------------------	
	Ensure one Fuel Handling Ventilation Exhaust System (FHVES) train is in operation and all operating FHVES trains are in the filtered mode.	Immediately
	OR	
	F.2 Suspend all operations involving fuel movement in the fuel building.	Immediately

(continued)

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. One Auxiliary Building Ventilation – High Gaseous Radioactivity (EMF-41) channel non-functional.	G.1.1 Initiate action to restore non-functional channel to FUNCTIONAL status.	Immediately
	<u>AND</u>	
	G.1.2 Verify EMF-36 is FUNCTIONAL (reference SLC 16.11-7) and in service for any affected unit in MODE 1, 2, 3 or 4.	Immediately
	<u>AND</u>	
	G.1.3 Restore non-functional channel to FUNCTIONAL status.	30 days
	<u>OR</u>	
	G.2 Ensure all operating ABFVES trains are in the filtered mode for any affected unit in Mode 1, 2, 3 or 4.	Immediately

(continued)

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. One Component Cooling Water System (EMF-46A & B) channel non-functional.	H.1 Collect and analyze grab samples for principal gamma emitters (listed in Table 16.11-1-1, NOTE 3) at a lower limit of detection of no more than $5x10^{-7}$ μCi/ml.	Once per 12 hours
	<u>AND</u>	
	H.2 Restore non-functional channel to FUNCTIONAL status.	30 days
I. One or more N-16 Leakage Monitor (EMF-71, 72, 73, & 74) channels non-functional.	I.1 Ensure that the Condenser Evacuation System Noble Gas Activity Monitor (EMF-33) is FUNCTIONAL and in operation.	Immediately
	<u>OR</u>	
	I.2 Ensure that Required Actions are met per SLC 16.11-7 if the Condenser Evacuation System Noble Gas Activity Monitor (EMF-33) is non-functional or not in operation.	Immediately
J. One Auxiliary Building Cooling Water System (EMF-89) channel non-functional.	J.1 Collect and analyze grab samples for principal gamma emitters (listed in Table 16.11-1-1, NOTE 3) at a lower limit of detection of no more than $5x10^{-7}$ μCi/ml.	Once per 7 days
	<u>AND</u>	
	J.2 Restore non-functional channel to FUNCTIONAL status.	30 days

TESTING REQUIREMENTS

--NOTE--
Refer to Table 16.7-10-1 to determine which TRs apply for each Radiation Monitoring for Plant Operations channel.

TEST	FREQUENCY
TR 16.7-10-1 Perform CHANNEL CHECK.	12 hours
TR 16.7-10-2 Perform CHANNEL OPERATIONAL TEST.	9 months
TR 16.7-10-3 Perform CHANNEL CALIBRATION.	18 months

Table 16.7-10-1

Radiation Monitoring Instrumentation for Plant Operations

MONITOR	APPLICABLE MODES	REQUIRED CHANNELS	ALARM/TRIP SETPOINT	TESTING REQUIREMENTS
1. Containment Atmosphere – High Gaseous Radioactivity (EMF-39 – Low Range)	1, 2, 3, 4, 5, 6	1	Note (a)	TR 16.7-10-1 TR 16.7-10-2 TR 16.7-10-3
2. Fuel Storage Pool Areas – High Gaseous Radioactivity (EMF-42)	With irradiated fuel in the fuel storage pool areas	1	$\leq 1.7 \times 10^{-4}$ μCi/ml	TR 16.7-10-1 TR 16.7-10-2 TR 16.7-10-3
3. Fuel Storage Pool Areas – Radiation Level (Fuel Bridge – 1EMF-15, 2EMF-4)	With fuel in the fuel storage pool areas	1	$\leq$ 15 mR/h Note (d)	TR 16.7-10-1 TR 16.7-10-2 TR 16.7-10-3
4. Control Room Air Intake – Radiation Level – High Gaseous Radioactivity (EMF-43A & B – Low Range)	At all times	2 (1/intake)	$\leq 1.7 \times 10^{-4}$ μCi/ml	TR 16.7-10-1 TR 16.7-10-2 TR 16.7-10-3
5. Auxiliary Building Ventilation – High Gaseous Radioactivity (EMF-41)	1, 2, 3, 4	1	$\leq 1.7 \times 10^{-4}$ μCi/ml	TR 16.7-10-1 TR 16.7-10-2 TR 16.7-10-3
6. Component Cooling Water System (EMF-46A & B)	At all times[e]	1[b]	$\leq 1 \times 10^{-3}$ μCi/ml	TR 16.7-10-1 TR 16.7-10-2 TR 16.7-10-3
7. N-16 Leakage Monitor (EMF-71, 72, 73, & 74)	1 (40-100% reactor power)	4 (1/steamline)	Note (c)	TR 16.7-10-1 TR 16.7-10-2 TR 16.7-10-3
8. Auxiliary Building Cooling Water System (EMF-89)	At all times	1	$\leq 1 \times 10^{-3}$ μCi/ml	TR 16.7-10-1 TR 16.7-10-2 TR 16.7-10-3

Table 16.7-10-1 Notes

(a) When venting or purging from containment to the atmosphere, the trip setpoint shall not exceed the equivalent limits of SLC 16.11-6 in accordance with the methodology and parameters in the ODCM. When not venting or purging in Modes 5 or 6, the alarm setpoint concentration (μCi/ml) shall be such that the actual submersion dose rate would not exceed 5 mR/hr without alarm. When not venting or purging in Modes 1 through 4, the alarm setpoint shall be no more than 3 times the containment atmosphere activity as indicated by the radiation monitor.

(b) For EMF-46A & B: The EMF monitor associated with the operating Component Cooling Water System train shall be FUNCTIONAL. This requirement is based on the existence of an interlock which blocks the EMF loss of flow alarm from being received in the control room when the associated train pump motor(s) are not running.

(c) The setpoint is as required by the primary to secondary leak rate monitoring program.

(d) Catawba's Spent Fuel Pools were originally licensed for compliance with 10 CFR 70.24. The basis for the 15 mR/hr setpoint can be found in 10 CFR 70.24(a)(2) which states, in part, "... The monitoring devices in the system shall have a preset alarm point of not less than 5 millirems per hour (in order to avoid false alarms) nor more than 20 millirems per hour. ..." Although Catawba received exemption from 10 CFR 70.24 in 1997, the 15 mR/hr setpoint limit for detection of inadvertent criticality in the Spent Fuel Pool is still appropriate. Catawba is presently committed to compliance with 10 CFR 50.68 which requires, in part, "(6) Radiation monitors are provided in storage and associated handling areas when fuel is present to detect excessive radiation levels and initiate appropriate safety actions."

Therefore, the setpoint may be elevated, using approved plant procedures, above 15 mR/hr during Independent Spent Fuel Storage Installation (ISFSI) Transportable Storage Container (TSC) transfer activities when the loaded TSC may generate dose rates in excess of 15 mR/hr at the detector location. The setpoint shall be returned to ≤ 15 mR/hr upon completion of the TSC transfer.

(e) The Component Cooling Water (CCW) radiation monitors are not considered to be non-functional just because there is no CCW flow through their respective trains. The EMFs would be considered non-functional if one of the inlet/outlet CCW isolation valves to the EMF were closed, if the EMF itself was not functioning properly, or if preventive maintenance/calibration activities were being performed on the EMF rendering it out of service. For the situation where the associated train related CCW pumps are not running and a section of the CCW System (e.g., CCW heat exchanger) has been isolated and drained such that the associated radiation monitor has no process fluid to monitor, grab samples are not required.

BASES

The FUNCTIONALITY of the radiation monitoring instrumentation for plant operations ensures that: (1) the associated action will be initiated when the radiation level monitored by each channel or combination thereof reaches its setpoint, (2) the specified coincidence logic is maintained, and (3) sufficient redundancy is maintained to permit a channel to be out of service for testing or maintenance. The radiation monitors for plant operations senses radiation levels in selected plant systems and locations and determines whether or not predetermined limits are being exceeded. The radiation monitors send actuation signals to initiate alarms or automatic isolation action and actuation of emergency exhaust or ventilation systems. Some of the final actuations are dependent on plant condition in addition to the actuation signals from the radiation monitors.

Operation of the Component Cooling Water (CCW) System Train A with the Train A Radiation Monitoring System (EMF) monitor non-functional and relying on the Train B EMF monitor for detection of radioactivity is not permissible. Likewise, operation of the CCW System Train B with the Train B EMF monitor non-functional and relying on the Train A EMF monitor for detection of radioactivity is not permissible. This is due to the interlock between the EMF monitor low-flow alarm and the operation of the CCW System pump motors on the same train. The EMF monitor in the operating CCW System pump train must be FUNCTIONAL, or the compensatory measures taken as specified.

In MODES 5 and 6, initiation of the Containment Purge Exhaust System (CPES) with EMF-39 non-functional is not permissible. The basis for Required Action B.1 is to allow the continued operation of the CPES with EMF-39 initially FUNCTIONAL. Continued operation of the CPES is contingent upon the ability of the affected unit to meet the requirements as noted in Required Action B.1.

REFERENCES

1. Letter from NRC to Gary R. Peterson, Duke, Issuance of Improved Technical Specifications Amendments for Catawba, September 30, 1998.

2. Letter from NRC to M. S. Tuckman, Duke, Issuance of Exemption to 10 CFR 70.24, Criticality Accident Requirements, July 29, 1997.

16.8 ELECTRICAL POWER SYSTEMS

16.8-1 Containment Penetration Conductor Overcurrent Protective Devices (CPCOPDs)

COMMITMENT Primary and backup CPCOPDs shown in Table 16.8-1-1 and 16.8-1-2 shall be FUNCTIONAL.

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

REMEDIAL ACTIONS

---NOTES---

1. Separate Condition entry is allowed for each penetration circuit.

2. Enter applicable Conditions and Required Actions for systems made inoperable or non-functional by CPCOPDs.

3. SLC 16.2-3 is not applicable to CPCOPDs in circuits which have their redundant devices tripped or removed, or their non-functional protective devices racked out or removed from the circuits.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more CPCOPD(s) non-functional.	A.1.1 De-energize the circuit(s) by tripping the associated redundant circuit breaker or removing the redundant fuse(s). <u>AND</u> A.1.2 Verify the associated redundant protective device(s) to be tripped or removed.	72 hours Once per 7 days (continued)

REMEDIAL ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	OR	
	A.2.1 De-energize the circuit(s) by racking out the non-functional circuit breaker or removing the non-functional protective device(s).	72 hours
	AND	
	A.2.2 Verify the non-functional device(s) are removed or racked out.	Once per 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

TESTING REQUIREMENTS

---NOTE---
TR 16.8-1-1, 16.8-1-2, and 16.8-1-3 are only required to be performed for 10% of the circuit breakers within each voltage level on a rotating basis during each testing interval.

TEST	FREQUENCY
TR 16.8-1-1 Perform a CHANNEL CALIBRATION of the associated protective relays for medium voltage circuits (4-15 kV).	18 months

(continued)

TESTING REQUIREMENTS (continued)

	TEST	FREQUENCY
TR 16.8-1-2	---------------------------------NOTE--------------------------------- For each circuit breaker found non-functional during these functional tests, an additional representative sample of ≥ 10% of all the circuit breakers of the non-functional type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested. --- Perform an integrated protective system functional test on each medium voltage (4-15 kV) circuit breaker which includes simulated automatic actuation of the system and verify that each relay and associated circuit breakers function as designed.	18 months
TR 16.8-1-3	--------------------------------NOTES-------------------------------- 1. Only required to be performed for 10% of each type of lower voltage circuit breakers on a rotating basis during each testing interval. 2. Circuit breakers found non-functional during functional testing shall be restored to FUNCTIONAL status prior to resuming operation of the circuit. 3. For each circuit breaker found non-functional during these functional tests, an additional representative sample of ≥ 10% of all the circuit breakers of the non-functional type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested. --- Inject a current in excess of the breaker's nominal setpoint, measure the response time, and verify that the measured response time is ≤ the manufacturer's specified response time.	18 months

(continued)

TESTING REQUIREMENTS (continued)

TEST		FREQUENCY
TR 16.8-1-4	Perform fuse inspection and maintenance program.	18 months
TR 16.8-1-5	Perform inspection and preventive maintenance on each circuit breaker in accordance with procedures prepared in conjunction with its manufacturer's recommendations.	60 months

BASES

Containment electrical penetrations and penetration conductors are protected by either deenergizing circuits not required during reactor operation or by demonstrating the FUNCTIONALITY of primary and backup overcurrent protection circuit breakers during periodic testing.

The TESTING REQUIREMENTS applicable to lower voltage circuit breakers provide assurance of breaker reliability by testing at least one representative sample of each manufacturer's brand of circuit breaker. Each manufacturer's molded case circuit breakers are grouped into representative samples which are then tested on a rotating basis to ensure that all breakers are tested. If a wide variety exists within any manufacturer's brand of circuit breakers, it is necessary to divide that manufacturer's breakers into groups and treat each group as a separate type of breaker for testing purposes.

Fuse testing is in accordance with IEEE Standard 242-1975 (Reference 2). This program will detect any significant degradation of the fuses or improperly sized fuses. Safety is further assured by the "fail-safe" nature of fuses; that is, if the fuse fails, the circuit will de-energize.

The lists of components for which this COMMITMENT is applicable exclude those circuits for which credible fault currents would not exceed the electrical penetration design rating.

REFERENCES

1. Letter from NRC to Gary R. Peterson, Duke, Issuance of Improved Technical Specifications Amendments for Catawba, September 30, 1998.

2. IEEE Standard 242-1975, "IEEE Recommended Practice for Protection and Coordination of Industrial and Commercial Power Systems".

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
1. 6900 VAC Swgr	
Primary Bkr RCP1A Backup Bkr 1TA-3	Reactor Coolant Pump 1A
Primary Bkr RCP1B Backup Bkr 1TB-3	Reactor Coolant Pump 1B
Primary Bkr RCP1C Backup Bkr 1TC-3	Reactor Coolant Pump 1C
Primary Bkr RCP1D Backup Bkr 1TD-3	Reactor Coolant Pump 1D
2. 600 VAC MCC	
1EMXC-F01B Primary Bkr Backup Fuse	Accumulator 1C Discharge Isol Vlv 1NI76A
1EMXC-F01C Primary Bkr Backup Fuse	Check Vlv Test Header Cont Isol Vlv 1NI95A
1EMXC-F02A Primary Bkr Backup Fuse	Train A Alternate Power to ND Letdn Vlv 1ND1B
1EMXC-F02B Primary Bkr Backup Fuse	Hot Leg Inj Check Vlv Test Isol Vlv 1NI153A
1EMXC-F03A Primary Bkr Backup Fuse	NC Pump 1C Thermal Barrier Outlet Isol Vlv 1KC345A
1EMXC-F03B Primary Bkr Backup Fuse	Nitrogen to PRT Cont Isol Inside Vlv 1NC54A
1EMXC-F03C Primary Bkr Backup Fuse	Pressurizer Power Operated Relief Isol Vlv 1NC33A
1EMXC-F05A Primary Bkr Backup Fuse	NCDT Vent Inside Cont Isol Vlv 1WL450A

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
1EMXC-F05B Primary Bkr Backup Fuse	Cont Sump Pumps Discharge Inside Cont Isol Vlv 1WL825A
1EMXC-F05C Primary Bkr Backup Fuse	Ventilation Unit Cond Drain Tnk Outside Cont Isol Vlv 1WL867A
1EMXC-F06A Primary Bkr Backup Fuse	NCDT Pumps Discharge Inside Cont Isol Vlv 1WL805A
1EMXC-F07B Primary Bkr Backup Fuse	Cont Hydrogen Purge Outlet Cont Isol Vlv 1VY17A
1EMXD-F01A Primary Bkr Backup Fuse	ND Pump 1A Suction from NC Loop B Vlv 1ND1B
1EMXD-F01B Primary Bkr Backup Fuse	Accumulator 1B Discharge Isol Vlv 1NI65B
1EMXD-F01C Primary Bkr Backup Fuse	NI Pump A to Hot Leg Check Vlv Test Isol Vlv 1NI122B
1EMXD-F02A Primary Bkr Backup Fuse	ND Pump 1B Suction from NC Loop C Vlv 1ND36B
1EMXD-F02B Primary Bkr Backup Fuse	ND to Hot Legs Chk 1NI125, 1NI129 Test Isol Vlv 1NI154B
1EMXD-F02C Primary Bkr Backup Fuse	Pressurizer Power Operated Relief Isol Vlv 1NC31B
1EMXD-F05A Primary Bkr Backup Fuse	Pressurizer Power Operated Relief Isol Vlv 1NC35B
1EMXD-F05B Primary Bkr	Rx Bldg Drain Hdr Inside Cont Isol Vlv 1KC429B

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Backup Fuse	
1EMXD-F05C Primary Bkr Backup Fuse	NCDT Hx Clng Water Return Inside Isol Vlv 1KC332B
1EMXD-F06A Primary Bkr Backup Fuse	NC Pump 1B Thermal Barrier Outlet Isol Vlv 1KC364B
1EMXD-F06B Primary Bkr Backup Fuse	NC Pumps Return Hdr Inside Cont Isol Vlv 1KC424B
1EMXK-F01C Primary Bkr Backup Fuse	Backup Nitrogen to PORV 1NC34A from Accum Tnk 1A Vlv 1NI438A
1EMXK-F02A Primary Bkr Backup Fuse	NC Pump 1A Thermal Barrier Outlet Isol Vlv 1KC394A
1EMXK-F02B Primary Bkr Backup Fuse	Lower Cont Ventilation Units Return Cont Isol Vlv 1RN484A
1EMXK-F02C Primary Bkr Backup Fuse	NV Supply to Pressurizer Vlv 1NV037A
1EMXK-F03A Primary Bkr Backup Fuse	S/G C Blowdown Line Sample Inside Cont Isol Vlv 1NM210A
1EMXK-F04A Primary Bkr Backup Fuse	S/G A Upper Shell Sample Inside Cont Isol Vlv 1NM187A
1EMXK-F04B Primary Bkr Backup Fuse	S/G A Blowdown Line Sample Inside Cont Isol Vlv 1NM190A
1EMXK-F04C Primary Bkr Backup Fuse	S/G C Upper Shell Sample Inside Cont Isol Vlv 1NM207A
1EMXK-F06A	Hydrogen Skimmer Fan 1A Inlet Vlv

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Primary Bkr Backup Fuse	1VX1A
1EMXK-F07C Primary Bkr Backup Fuse	Electric Hydrogen Recombiner Power Supply Panel 1A
1EMXK-F09A Primary Bkr Backup Fuse	Accum 1A Discharge Isol Vlv 1NI54A
1EMXK-F09C Primary Bkr Backup Fuse	NC Pump Oil Fill Header Cont Isol Vlv 1NC196A
1EMXK-F10A Primary Bkr Backup Fuse	Cont Air Return Damper 1ARF-D-2
1EMXK-F10B Primary Bkr Backup Fuse	VQ Fans Suction from Cont Isol Vlv 1VQ2A
1EMXK-F10C Primary Bkr Backup Fuse	Cont Air Addition Cont Isol Vlv 1VQ16A
1EMXK-F11A Primary Bkr Backup Fuse	Cont Air Return Fan Motor 1A
1EMXK-F11B Primary Bkr Backup Fuse	Hydrogen Skimmer Fan Motor 1A
1EMXL-F01B Primary Bkr Backup Fuse	Trn B Alternate Power to ND Letdn Vlv 1ND37A
1EMXL-F01C Primary Bkr Backup Fuse	NI Accum D Sample Line Inside Cont Isol Vlv 1NM81B
1EMXL-F02A Primary Bkr Backup Fuse	NC Pump 1D Thermal Barrier Outlet Isol Vlv 1KC413B

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
1EMXL-F02B Primary Bkr Backup Fuse	Air Handling Units Glycol Return Cont Isol Vlv 1NF233B
1EMXL-F02C Primary Bkr Backup Fuse	NI Accum C Sample Line Inside Cont Isol Vlv 1NM78B
1EMXL-F03A Primary Bkr Backup Fuse	S/G D Blowdown Sample Line Inside Cont Isol Vlv 1NM220B
1EMXL-F03B Primary Bkr Backup Fuse	NI Accum A Sample Line Inside Cont Isol Vlv 1NM72B
1EMXL-F03C Primary Bkr Backup Fuse	NI Accum B Sample Line Inside Cont Isol Vlv 1NM75B
1EMXL-F04A Primary Bkr Backup Fuse	S/G B Upper Shell Sample Inside Cont Isol Vlv 1NM197B
1EMXL-F04B Primary Bkr Backup Fuse	S/G B Blowdown Sample Line Inside Cont Isol Vlv 1NM200B
1EMXL-F04C Primary Bkr Backup Fuse	S/G D Upper Shell Sample Inside Cont Isol Vlv 1NM217B
1EMXL-F06A Primary Bkr Backup Fuse	Hydrogen Skimmer Fan 1B Inlet Vlv 1VX2B
1EMXL-F06B Primary Bkr Backup Fuse	Backup Nitrogen to PORV 1NC32B from Accum Tnk 1B Vlv 1NI439B
1EMXL-F07C Primary Bkr Backup Fuse	Electric Hydrogen Recombiner Power Supply Panel 1B
1EMXL-F09A Primary Bkr Backup Fuse	Accum 1D Discharge Isol Vlv 1NI88B

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
1EMXL-F10A Primary Bkr Backup Fuse	Cont Air Return Damper 1ARF-D-4
1EMXL-F10B Primary Bkr Backup Fuse	Reactor Vessel Head Vent Vlv 1NC251B
1EMXL-F10C Primary Bkr Backup Fuse	Reactor Vessel Head Vent Vlv 1NC252B
1EMXL-F11A Primary Bkr Backup Fuse	Cont Air Return Fan Motor 1B
1EMXL-F11B Primary Bkr Backup Fuse	Hydrogen Skimmer Fan Motor 1B
1EMXS-F01B Primary Bkr Backup Fuse	NC Pumps Seal Return Inside Cont Isol Vlv 1NV89A
1EMXS-F02A Primary Bkr Backup Fuse	ND Pump 1B Suction from NC Loop C Vlv 1ND37A
1EMXS-F02B Primary Bkr Backup Fuse	Reactor Vessel Head Vent Vlv 1NC250A
1EMXS-F03D Primary Bkr Backup Fuse	ND Pump 1A Suction from NC Loop B Vlv 1ND2A
1EMXS-F03E Primary Bkr Backup Fuse	Reactor Vessel Head Vent Vlv 1NC253A
1EMXS-F04B Primary Bkr Backup Fuse	S/G D Blowdown Inside Cont Isol Vlv 1BB8A
1EMXS-F04C Primary Bkr	S/G B Blowdown Inside Cont Isol Vlv 1BB19A

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Backup Fuse	
1EMXS-F05A Primary Bkr Backup Fuse	S/G A Blowdown Inside Cont Isol Vlv 1BB56A
1EMXS-F05B Primary Bkr Backup Fuse	S/G C Blowdown Inside Cont Isol Vlv 1BB60A
1EMXS-F05C Primary Bkr Backup Fuse	Pressurizer Liquid Sample Line Inside Cont Isol Vlv 1NM3A
1EMXS-F06A Primary Bkr Backup Fuse	Pressurizer Steam Sample Line Inside Cont Isol Vlv 1NM6A
1EMXS-F06B Primary Bkr Backup Fuse	NC Hot Leg A Sample Line Inside Cont Isol Vlv 1NM22A
1EMXS-F06C Primary Bkr Backup Fuse	NC Hot Leg C Sample Line Inside Cont Isol Vlv 1NM25A
1MXM-F01A Primary Bkr Backup Fuse	Reactor Coolant Pump Motor Drain Tnk Pump Motor
1MXM-F02A Primary Bkr Backup Fuse	NC Pump 1B Oil Lift Pump Motor 1
1MXM-F02B Primary Bkr Backup Fuse	NC Pump 1C Oil Lift Pump Motor 1
1MXM-F03A Primary Bkr Backup Fuse	Ice Condenser Power Transformer ICT1A
1MXM-F03B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B6 Fan Motor A & B
1MXM-F03C	Ice Condenser Equipment Access

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Primary Bkr Backup Fuse	Door Hoist Motor 1A
1MXM-F04D Primary Bkr Backup Fuse	Lighting Transformer 1LR10
1MXM-F04E Primary Bkr Backup Fuse	Lighting Transformer 1LR13
1MXM-F05A Primary Bkr Backup Fuse	175 Ton Polar Crane and 25 Ton Aux Crane No. R013 and R015
1MXM-F05C Primary Bkr Backup Fuse	Upper Containment Welding Feeder
1MXM-F06A Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A7 Fan Motor A & B
1MXM-F06B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B8 Fan Motor A & B
1MXM-F06C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A9 Fan Motor A & B
1MXM-F06D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B10 Fan Motor A & B
1MXM-F07B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A13 Fan Motor A & B
1MXM-F07C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B14 Fan Motor A & B
1MXM-F08D Primary Bkr Backup Fuse	Ice Condenser Refrigeration Floor Cool Defrost Heater 1A

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
1MXM-F09A Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A1 Fan Motor A & B
1MXM-F09B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B2 Fan Motor A & B
1MXM-F09C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A3 Fan Motor A & B
1MXM-F09D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B4 Fan Motor A & B
1MXM-F10A Primary Bkr Backup Fuse	Cont Floor and Equipment Sump Pump Motor 1A1
1MXM-F10B Primary Bkr Backup Fuse	Cont Floor and Equipment Sump Pump Motor 1B1
1MXN-F01F Primary Bkr Backup Fuse	Stud Tensioner Hoist 1B
1MXN-F02A Primary Bkr Backup Fuse	NC Pump 1B Oil Lift Pump Motor 2
1MXN-F02B Primary Bkr Backup Fuse	NC Pump 1C Oil Lift Pump Motor 2
1MXN-F02E Primary Bkr Backup Fuse	Stud Tensioner Hoist 1C
1MXN-F03A Primary Bkr Backup Fuse	Ice Condenser Power Transformer ICT1B
1MXN-F03B Primary Bkr Backup Fuse	Ice Condenser Bridge Crane 1 Crane No. R011

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
1MXN-F03E Primary Bkr Backup Fuse	Stud Tensioner Hoist 1A
1MXN-F04D Primary Bkr Backup Fuse	Lighting Transformer 1LR5
1MXN-F04E Primary Bkr Backup Fuse	Lighting Transformer 1LR6
1MXN-F05A Primary Bkr Backup Fuse	Ice Condenser Refrigeration Floor Cool Defrost Heater 1B
1MXN-F05B Primary Bkr Backup Fuse	Ice Condenser Refrigeration Floor Cool Pump Motor 1B
1MXN-F05C Primary Bkr Backup Fuse	Ice Condenser Equipment Access Door Hoist Motor 1B
1MXN-F06A Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B1 Fan Motor A & B
1MXN-F06B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A2 Fan Motor A & B
1MXN-F06C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B3 Fan Motor A & B
1MXN-F06D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A4 Fan Motor A & B
1MXN-F07B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B5 Fan Motor A & B
1MXN-F07C Primary Bkr	Ice Condenser Air Handling Unit 1A6 Fan Motor A & B

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Backup Fuse	
1MXN-F08A Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B7 Fan Motor A & B
1MXN-F08B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A8 Fan Motor A & B
1MXN-F08C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B9 Fan Motor A & B
1MXN-F08D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A10 Fan Motor A & B
1MXN-F09A Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B11 Fan Motor A & B
1MXN-F09B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A12 Fan Motor A & B
1MXN-F09C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B13 Fan Motor A & B
1MXN-F09D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A14 Fan Motor A & B
1MXN-F10A Primary Bkr Backup Fuse	Cont Floor and Equipment Sump Pump Motor 1A2
1MXN-F10B Primary Bkr Backup Fuse	Cont Floor and Equipment Sump Pump Motor 1B2
1MXN-F10C Primary Bkr Backup Fuse	Incore Instrumentation Sump Pump Motor 1
1MXN-F10D	Ice Condenser Air Handling Unit

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Primary Bkr Backup Fuse	1B15 Fan Motor A & B
1MXO-F01A Primary Bkr Backup Fuse	Upper Cont Air Return Fan Motor 1C
1MXO-F02B Primary Bkr Backup Fuse	Control Rod Drive Ventilation Fan Motor 1A
1MXO-F03A Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 1C Fan Motor
1MXO-F04C Primary Bkr Backup Fuse	Upper Cont Ventilation Unit 1C Fan Motor
1MXO-F05C Primary Bkr Backup Fuse	Cont Pipe Tunnel Booster Fan Motor 1A
1MXP-F01A Primary Bkr Backup Fuse	Upper Cont Return Air Fan 1B
1MXP-F02B Primary Bkr Backup Fuse	Control Rod Drive Ventilation Fan Motor 1B
1MXP-F03A Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 1B Fan Motor
1MXP-F04D Primary Bkr Backup Fuse	Upper Cont Ventilation Unit 1B Fan Motor
1MXP-F05C Primary Bkr Backup Fuse	Cont Pipe Tunnel Booster Fan Motor 1B
1MXQ-F01A Primary Bkr Backup Fuse	Upper Cont Return Air Fan Motor 1A

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
1MXQ-F01B Primary Bkr Backup Fuse	Incore Instrument Room Ventilation Unit 1A Fan Motor
1MXQ-F02B Primary Bkr Backup Fuse	Control Rod Drive Ventilation Fan Motor 1C
1MXQ-F03A Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 1A Fan Motor
1MXQ-F04C Primary Bkr Backup Fuse	Upper Cont Ventilation Unit 1A Fan Motor
1MXR-F01A Primary Bkr Backup Fuse	Upper Cont Return Air Fan Motor 1D
1MXR-F01B Primary Bkr Backup Fuse	Incore Instrument Room Ventilation Unit 1B Fan Motor
1MXR-F02B Primary Bkr Backup Fuse	Control Rod Drive Ventilation Fan Motor 1D
1MXR-F03A Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 1D Fan Motor
1MXR-F04C Primary Bkr Backup Fuse	Upper Cont Ventilation Unit 1D Fan Motor
1MXY-F02A Primary Bkr Backup Fuse	NC Pump 1A Oil Lift Pump Motor 1
1MXY-F02B Primary Bkr Backup Fuse	NC Pump 1D Oil Lift Pump Motor 1
1MXY-F02C Primary Bkr Backup Fuse	Rx Bldg Lower Cont Welding Machine Receptacle 1RCPL0185

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
1MXY-F02D Primary Bkr Backup Fuse	Upper Cont Rx Bldg Welding Receptacle 1RCPL0193
1MXY-F03A Primary Bkr Backup Fuse	Reactor Coolant Drain Tnk Pump Motor 1A
1MXY-F03D Primary Bkr Backup Fuse	Ice Condenser Refrigeration Floor Cool Pump Motor 1A
1MXY-F05A Primary Bkr Backup Fuse	Lighting Transformer 1LR8
1MXY-F05B Primary Bkr Backup Fuse	Lighting Transformer 1LR11
1MXY-F05C Primary Bkr Backup Fuse	Lighting Transformer 1LR14
1MXY-F06A Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A5 Fan Motor A & B
1MXY-F06B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A11 Fan Motor A & B
1MXY-F06C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1B12 Fan Motor A & B
1MXY-F06D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 1A15 Fan Motor A & B
1MXY-F08A Primary Bkr Backup Fuse	Incore Drive Assembly Motor 1A
1MXY-F08B Primary Bkr	Incore Drive Assembly Motor 1C

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Backup Fuse	
1MXY-F08C Primary Bkr Backup Fuse	Incore Drive Assembly Motor 1E
1MXY-F08D Primary Bkr Backup Fuse	Lower Cont Auxiliary Charcoal Filter Unit Fan Motor 1A
1MXZ-F02A Primary Bkr Backup Fuse	NC Pump 1A Oil Lift Pump Motor 2
1MXZ-F02B Primary Bkr Backup Fuse	NC Pump 1D Oil Lift Pump Motor 2
1MXZ-F03A Primary Bkr Backup Fuse	Reactor Coolant Drain Tnk Pump Motor 1B
1MXZ-F04B Primary Bkr Backup Fuse	Lighting Transformer 1LR1
1MXZ-F04C Primary Bkr Backup Fuse	Lighting Transformer 1LR2
1MXZ-F04D Primary Bkr Backup Fuse	Lighting Transformer 1LR3
1MXZ-F05A Primary Bkr Backup Fuse	Reactor Coolant Pump Jib Hoist No. R019 through R022
1MXZ-F05C Primary Bkr Backup Fuse	Lower Cont Auxiliary Charcoal Filter Unit Fan Motor 1B
1MXZ-F06A Primary Bkr Backup Fuse	Incore Drive Assembly Motor 1B
1MXZ-F06B	Incore Drive Assembly Motor 1D

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Primary Bkr Backup Fuse	
1MXZ-F06C Primary Bkr Backup Fuse	Incore Drive Assembly Motor 1F
1MXZ-F06D Primary Bkr Backup Fuse	Lower Cont Rx Bldg Welding Receptacle 1RCPL0194
1MXZ-F07B Primary Bkr Backup Fuse	Lighting Transformer 1LR4
1MXZ-F07C Primary Bkr Backup Fuse	5 Ton Jib Crane in Cont Crane No. R005
1MXZ-F07D Primary Bkr Backup Fuse	Reactor Cavity Manipulator Crane No. R007 and R027
1MXZ-F08A Primary Bkr Backup Fuse	S/G Drain Pump Motor 1
1MXZ-F08C Primary Bkr Backup Fuse	15 Ton Equipment Access Hatch Hoist Crane No. R009
1MXZ-F08D Primary Bkr Backup Fuse	Control Rod Drive 2 Ton Jib Hoist Crane No. R017
1MXZ-F08E Primary Bkr Backup Fuse	Reactor Side Fuel Handling Control Console
SMXG-F01C Primary Bkr Backup Fuse	Standby Makeup Pump Drain Isol Vlv 1NV876
SMXG-F05C Primary Bkr Backup Fuse	Pressurizer Heaters 28, 55, and 56

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION		SYSTEM POWERED
	SMXG-F06A Primary Bkr Backup Fuse	Standby Makeup Pump to Seal Water Line Isol Vlv 1NV877
3.	600 VAC Pressurizer Heater Power Panels	
	PHP1A-F01A Primary Bkr Backup Fuse	Pressurizer Heaters 1, 2, and 22
	PHP1A-F01B Primary Bkr Backup Fuse	Pressurizer Heaters 5, 6, and 27
	PHP1A-F01C Primary Bkr Backup Fuse	Pressurizer Heaters 9, 10, and 32
	PHP1A-F02C Primary Bkr Backup Fuse	Pressurizer Heaters 11, 12, and 35
	PHP1A-F02D Primary Bkr Backup Fuse	Pressurizer Heaters 13, 14, and 37
	PHP1A-F02E Primary Bkr Backup Fuse	Pressurizer Heaters 17, 18, and 42
	PHP1B-F01A Primary Bkr Backup Fuse	Pressurizer Heaters 21, 47, and 48
	PHP1B-F01B Primary Bkr Backup Fuse	Pressurizer Heaters 26, 53, and 54
	PHP1B-F02C Primary Bkr Backup Fuse	Pressurizer Heaters 36, 65, and 66
	PHP1B-F02D Primary Bkr Backup Fuse	Pressurizer Heaters 41, 71, and 72

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
PHP1B-F02E Primary Bkr Backup Fuse	Pressurizer Heaters 46, 77, and 78
PHP1C-F01A Primary Bkr Backup Fuse	Pressurizer Heaters 7, 8, and 30
PHP1C-F01B Primary Bkr Backup Fuse	Pressurizer Heaters 19, 20, and 45
PHP1C-F01C Primary Bkr Backup Fuse	Pressurizer Heaters 23, 49, and 50
PHP1C-F01D Primary Bkr Backup Fuse	Pressurizer Heaters 29, 57, and 58
PHP1C-F02C Primary Bkr Backup Fuse	Pressurizer Heaters 34, 61, and 62
PHP1C-F02D Primary Bkr Backup Fuse	Pressurizer Heaters 39, 69, and 70
PHP1C-F02E Primary Bkr Backup Fuse	Pressurizer Heaters 44, 75, and 76
PHP1D-F01A Primary Bkr Backup Fuse	Pressurizer Heaters 3, 4, and 25
PHP1D-F01B Primary Bkr Backup Fuse	Pressurizer Heaters 15, 16, and 40
PHP1D-F01C Primary Bkr Backup Fuse	Spare
PHP1D-F02C Primary Bkr Backup Fuse	Spare

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION		SYSTEM POWERED
	PHP1D-F02D Primary Bkr Backup Fuse	Pressurizer Heaters 38, 67, and 68
	PHP1D-F02E Primary Bkr Backup Fuse	Pressurizer Heaters 43, 73, and 74
4.	250 VDC Reactor Building Deadlight Panelboard	
	1DLD-2 Primary Bkr Backup Fuse	Lighting Panelboard No. 1LR1, 1LR2, 1LR3, 1LR4
	1DLD-3 Primary Bkr Backup Fuse	Lighting Panelboard No. 1LR13, 1LR14
	1DLD-4 Primary Bkr Backup Fuse	Lighting Panelboard No. 1LR5, 1LR6
	1DLD-5 Primary Bkr Backup Fuse	Lighting Panelboard No. 1LR10, 1LR11
	1DLD-10 Primary Bkr Backup Fuse	Lighting Panelboard No. 1LR8
5.	120 VAC Panelboards	
	1ELB-5 Primary Bkr Backup Fuse	Emergency AC Lighting
	1ELB-7 Primary Bkr Backup Fuse	Emergency AC Lighting
	1ELB-13 Primary Bkr Backup Fuse	Emergency AC Lighting
	1ELB-15	Emergency AC Lighting

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Primary Bkr Backup Fuse	
1ELB-17 Primary Bkr Backup Fuse	Emergency AC Lighting
1KPM-1 Primary Bkr Backup Fuse	NC Pump Motor 1A Space Heater
1KPM-2 Primary Bkr Backup Fuse	NC Pump Motor 1C Space Heater
1KPM-7-1 Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 1A Fan Motor Space Heater
1KPM-8-1 Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 1C Fan Motor Space Heater
1KPM-24 Primary Bkr Backup Fuse	Control Rod Drive Ventilation Fan Motor 1A, 1B, 1C, 1D Space Heaters
1KPM-24-10 Primary Fuse Backup Fuse	Control Rod Drive Ventilation Fan Motor 1A Space Heaters
1KPM-24-11 Primary Fuse Backup Fuse	Control Rod Drive Ventilation Fan Motor 1B Space Heaters
1KPM-24-12 Primary Fuse Backup Fuse	Control Rod Drive Ventilation Fan Motor 1C Space Heaters
1KPM-24-13 Primary Fuse Backup Fuse	Control Rod Drive Ventilation Fan Motor 1D Space Heaters
1KPM-33 Primary Bkr Backup Fuse	NI Temperature Transmitters 1NITT5800, 1NITT5810, 1NITT5820, 1NITT5830

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
1KPM-33-04 Primary Fuse	NI Temperature Transmitter 1NITT5800
1KPM-33-05 Primary Fuse	NI Temperature Transmitter 1NITT5810
1KPM-33-06 Primary Fuse	NI Temperature Transmitter 1NITT5820
1KPM-33-07 Primary Fuse	NI Temperature Transmitter 1NITT5830
1KPN-1 Primary Bkr Backup Fuse	NC Pump Motor 1B Space Heater
1KPN-2 Primary Bkr Backup Fuse	NC Pump Motor 1D Space Heater
1KPN-7-1 Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 1B Fan Motor Space Heater
1KPN-08 Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 1D Fan Motor Space Heater, NC Pump Seal Standpipe Vent and Drain Vlvs 1NV105, 1NV106, 1NV110, 1NV111, 1NV115, 1NV116, 1NV120, 1NV121
1KPN-08-01 Primary Fuse Backup Fuse	Lower Cont Ventilation Unit 1D Fan Motor Space Heater
1KPN-08-02 Primary Fuse Backup Fuse	NC Pump 1A Standpipe Drain and Overflow Vlvs 1NV105 and 1NV106
1KPN-08-03 Primary Fuse Backup Fuse	NC Pump 1B Standpipe Drain and Overflow Vlvs 1NV110 and 1NV111
1KPN-08-04 Primary Fuse Backup Fuse	NC Pump 1C Standpipe Drain and Overflow Vlvs 1NV115 and 1NV116
1KPN-08-05	NC Pump 1D Standpipe Drain and

Table 16.8-1-1
Unit 1 CPCOPDs

DEVICE NUMBER AND LOCATION		SYSTEM POWERED
	Primary Fuse Backup Fuse	Overflow Vlvs 1NV120 and 1NV121
	1KPN-11 Primary Bkr Backup Fuse	Misc Control Power for 1ATC24
6.	DC Welding Circuits	
	1EQCB0001 Primary Bkr – AA Backup Bkr – AB	Spare
	1EQCB0002 Primary Bkr – AA Backup Bkr – AB	Spare

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
1. 6900 VAC Swgr	
Primary Bkr RCP2A Backup Bkr 2TA-3	Reactor Coolant Pump 2A
Primary Bkr RCP2B Backup Bkr 2TB-3	Reactor Coolant Pump 2B
Primary Bkr RCP2C Backup Bkr 2TC-3	Reactor Coolant Pump 2C
Primary Bkr RCP2D Backup Bkr 2TD-3	Reactor Coolant Pump 2D
2. 600 VAC MCC	
2EMXC-F01B Primary Bkr Backup Fuse	Accumulator 2C Discharge Isol Vlv 2NI76A
2EMXC-F01C Primary Bkr Backup Fuse	Check Vlv Test Header Cont Isol Vlv 2NI95A
2EMXC-F02A Primary Bkr Backup Fuse	Train A Alternate Power to ND Letdn Vlv 2ND1B
2EMXC-F02B Primary Bkr Backup Fuse	Hot Leg Inj Check Vlv Test Isol Vlv 2NI153A
2EMXC-F03A Primary Bkr Backup Fuse	NC Pump 2C Thermal Barrier Outlet Isol Vlv 2KC345A
2EMXC-F03B Primary Bkr Backup Fuse	Nitrogen to PRT Cont Isol Inside Vlv 2NC54A
2EMXC-F03C Primary Bkr Backup Fuse	Pressurizer Power Operated Relief Isol Vlv 2NC33A
2EMXC-F05A	NCDT Vent Inside Cont Isol Vlv

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Primary Bkr Backup Fuse	2WL450A
2EMXC-F05B Primary Bkr Backup Fuse	Cont Sump Pumps Discharge Inside Cont Isol Vlv 2WL825A
2EMXC-F05C Primary Bkr Backup Fuse	Ventilation Unit Cond Drain Tnk Outside Cont Isol Vlv 2WL867A
2EMXC-F06A Primary Bkr Backup Fuse	NCDT Pumps Discharge Inside Cont Isol Vlv 2WL805A
2EMXC-F07B Primary Bkr Backup Fuse	Cont Hydrogen Purge Outlet Cont Isol Vlv 2VY17A
2EMXD-F01A Primary Bkr Backup Fuse	ND Pump 2A Suction from NC Loop B Vlv 2ND1B
2EMXD-F01B Primary Bkr Backup Fuse	Accumulator 2B Discharge Isol Vlv 2NI65B
2EMXD-F01C Primary Bkr Backup Fuse	NI Pump A to Hot Leg Check Vlv Test Isol Vlv 2NI122B
2EMXD-F02A Primary Bkr Backup Fuse	ND Pump 2B Suction from NC Loop C Vlv 2ND36B
2EMXD-F02B Primary Bkr Backup Fuse	ND to Hot Legs Chk 2NI125, 2NI129 Test Isol Vlv 2NI154B
2EMXD-F02C Primary Bkr Backup Fuse	Pressurizer Power Operated Relief Isol Vlv 2NC31B
2EMXD-F05A Primary Bkr	Pressurizer Power Operated Relief Isol Vlv 2NC35B

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Backup Fuse	
2EMXD-F05B Primary Bkr Backup Fuse	Rx Bldg Drain Hdr Inside Cont Isol Vlv 2KC429B
2EMXD-F05C Primary Bkr Backup Fuse	NCDT Hx Clng Water Return Inside Isol Vlv 2KC332B
2EMXD-F06A Primary Bkr Backup Fuse	NC Pump 2B Thermal Barrier Outlet Isol Vlv 2KC364B
2EMXD-F06B Primary Bkr Backup Fuse	NC Pumps Return Hdr Inside Cont Isol Vlv 2KC424B
2EMXK-F01C Primary Bkr Backup Fuse	Backup Nitrogen to PORV 2NC34A from Accum Tnk 2A Vlv 2NI438A
2EMXK-F02A Primary Bkr Backup Fuse	NC Pump 2A Thermal Barrier Outlet Isol Vlv 2KC394A
2EMXK-F02B Primary Bkr Backup Fuse	Lower Cont Ventilation Units Return Cont Isol Vlv 2RN484A
2EMXK-F02C Primary Bkr Backup Fuse	NV Supply to Pressurizer Vlv 2NV037A
2EMXK-F03A Primary Bkr Backup Fuse	S/G C Blowdown Line Sample Inside Cont Isol Vlv 2NM210A
2EMXK-F04A Primary Bkr Backup Fuse	S/G A Upper Shell Sample Inside Cont Isol Vlv 2NM187A
2EMXK-F04B Primary Bkr Backup Fuse	S/G A Blowdown Line Sample Inside Cont Isol Vlv 2NM190A

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2EMXK-F04C Primary Bkr Backup Fuse	S/G C Upper Shell Sample Inside Cont Isol Vlv 2NM207A
2EMXK-F06A Primary Bkr Backup Fuse	Hydrogen Skimmer Fan 2A Inlet Vlv 2VX1A
2EMXK-F07C Primary Bkr Backup Fuse	Electric Hydrogen Recombiner Power Supply Panel 2A
2EMXK-F09A Primary Bkr Backup Fuse	Accum 2A Discharge Isol Vlv 2NI54A
2EMXK-F09C Primary Bkr Backup Fuse	NC Pump Oil Fill Header Cont Isol Vlv 2NC196A
2EMXK-F10A Primary Bkr Backup Fuse	Cont Air Return Damper 2ARF-D-2
2EMXK-F10B Primary Bkr Backup Fuse	VQ Fans Suction from Cont Isol Vlv 2VQ2A
2EMXK-F10C Primary Bkr Backup Fuse	Cont Air Addition Cont Isol Vlv 2VQ16A
2EMXK-F11A Primary Bkr Backup Fuse	Cont Air Return Fan Motor 2A
2EMXK-F11B Primary Bkr Backup Fuse	Hydrogen Skimmer Fan Motor 2A
2EMXL-F01B Primary Bkr Backup Fuse	Trn B Alternate Power to ND Letdn Vlv 2ND37A

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2EMXL-F01C Primary Bkr Backup Fuse	NI Accum D Sample Line Inside Cont Isol Vlv 2NM81B
2EMXL-F02A Primary Bkr Backup Fuse	NC Pump 2D Thermal Barrier Outlet Isol Vlv 2KC413B
2EMXL-F02B Primary Bkr Backup Fuse	Air Handling Units Glycol Return Cont Isol Vlv 2NF233B
2EMXL-F02C Primary Bkr Backup Fuse	NI Accum C Sample Line Inside Cont Isol Vlv 2NM78B
2EMXL-F03A Primary Bkr Backup Fuse	S/G D Blowdown Sample Line Inside Cont Isol Vlv 2NM220B
2EMXL-F03B Primary Bkr Backup Fuse	NI Accum A Sample Line Inside Cont Isol Vlv 2NM72B
2EMXL-F03C Primary Bkr Backup Fuse	NI Accum B Sample Line Inside Cont Isol Vlv 2NM75B
2EMXL-F04A Primary Bkr Backup Fuse	S/G B Upper Shell Sample Inside Cont Isol Vlv 2NM197B
2EMXL-F04B Primary Bkr Backup Fuse	S/G B Blowdown Sample Line Inside Cont Isol Vlv 2NM200B
2EMXL-F04C Primary Bkr Backup Fuse	S/G D Upper Shell Sample Inside Cont Isol Vlv 2NM217B
2EMXL-F06A Primary Bkr Backup Fuse	Hydrogen Skimmer Fan 2B Inlet Vlv 2VX2B
2EMXL-F06B	Backup Nitrogen to PORV 2NC32B

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Primary Bkr Backup Fuse	from Accum Tnk 2B Vlv 2NI439B
2EMXL-F07C Primary Bkr Backup Fuse	Electric Hydrogen Recombiner Power Supply Panel 2B
2EMXL-F09A Primary Bkr Backup Fuse	Accum 2D Discharge Isol Vlv 2NI88B
2EMXL-F10A Primary Bkr Backup Fuse	Cont Air Return Damper 2ARF-D-4
2EMXL-F10B Primary Bkr Backup Fuse	Reactor Vessel Head Vent Vlv 2NC251B
2EMXL-F10C Primary Bkr Backup Fuse	Reactor Vessel Head Vent Vlv 2NC252B
2EMXL-F11A Primary Bkr Backup Fuse	Cont Air Return Fan Motor 2B
2EMXL-F11B Primary Bkr Backup Fuse	Hydrogen Skimmer Fan Motor 2B
2EMXS-F01B Primary Bkr Backup Fuse	NC Pumps Seal Return Inside Cont Isol Vlv 2NV89A
2EMXS-F02A Primary Bkr Backup Fuse	ND Pump 2B Suction from NC Loop C Vlv 2ND37A
2EMXS-F02B Primary Bkr Backup Fuse	Reactor Vessel Head Vent Vlv 2NC250A
2EMXS-F03D Primary Bkr	ND Pump 2A Suction from NC Loop B Vlv 2ND2A

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Backup Fuse	
2EMXS-F03E Primary Bkr Backup Fuse	Reactor Vessel Head Vent Vlv 2NC253A
2EMXS-F04B Primary Bkr Backup Fuse	S/G D Blowdown Inside Cont Isol Vlv 2BB8A
2EMXS-F04C Primary Bkr Backup Fuse	S/G B Blowdown Inside Cont Isol Vlv 2BB19A
2EMXS-F05A Primary Bkr Backup Fuse	S/G A Blowdown Inside Cont Isol Vlv 2BB56A
2EMXS-F05B Primary Bkr Backup Fuse	S/G C Blowdown Inside Cont Isol Vlv 2BB60A
2EMXS-F05C Primary Bkr Backup Fuse	Pressurizer Liquid Sample Line Inside Cont Isol Vlv 2NM3A
2EMXS-F06A Primary Bkr Backup Fuse	Pressurizer Steam Sample Line Inside Cont Isol Vlv 2NM6A
2EMXS-F06B Primary Bkr Backup Fuse	NC Hot Leg A Sample Line Inside Cont Isol Vlv 2NM22A
2EMXS-F06C Primary Bkr Backup Fuse	NC Hot Leg C Sample Line Inside Cont Isol Vlv 2NM25A
2MXM-F01A Primary Bkr Backup Fuse	Reactor Coolant Pump Motor Drain Tnk Pump Motor
2MXM-F02A Primary Bkr Backup Fuse	NC Pump 2B Oil Lift Pump Motor 1

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2MXM-F02B Primary Bkr Backup Fuse	NC Pump 2C Oil Lift Pump Motor 1
2MXM-F03A Primary Bkr Backup Fuse	Ice Condenser Power Transformer ICT2A
2MXM-F03B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B6 Fan Motor A & B
2MXM-F03C Primary Bkr Backup Fuse	Ice Condenser Equipment Access Door Hoist Motor 2A
2MXM-F04D Primary Bkr Backup Fuse	Lighting Transformer 2LR10
2MXM-F04E Primary Bkr Backup Fuse	Lighting Transformer 2LR13
2MXM-F05A Primary Bkr Backup Fuse	175 Ton Polar Crane and 25 Ton Aux Crane No. R014 and R016
2MXM-F05C Primary Bkr Backup Fuse	Upper Containment Welding Feeder
2MXM-F06A Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A7 Fan Motor A & B
2MXM-F06B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B8 Fan Motor A & B
2MXM-F06C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A9 Fan Motor A & B

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2MXM-F06D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B10 Fan Motor A & B
2MXM-F07B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A13 Fan Motor A & B
2MXM-F07C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B14 Fan Motor A & B
2MXM-F08D Primary Bkr Backup Fuse	Ice Condenser Refrigeration Floor Cool Defrost Heater 2A
2MXM-F09A Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A1 Fan Motor A & B
2MXM-F09B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B2 Fan Motor A & B
2MXM-F09C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A3 Fan Motor A & B
2MXM-F09D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B4 Fan Motor A & B
2MXM-F10A Primary Bkr Backup Fuse	Cont Floor and Equipment Sump Pump Motor 2A1
2MXM-F10B Primary Bkr Backup Fuse	Cont Floor and Equipment Sump Pump Motor 2B1
2MXN-F01F Primary Bkr Backup Fuse	Stud Tensioner Hoist 2B
2MXN-F02A	NC Pump 2B Oil Lift Pump Motor 2

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Primary Bkr Backup Fuse	
2MXN-F02B Primary Bkr Backup Fuse	NC Pump 2C Oil Lift Pump Motor 2
2MXN-F02E Primary Bkr Backup Fuse	Stud Tensioner Hoist 2C
2MXN-F03A Primary Bkr Backup Fuse	Ice Condenser Power Transformer ICT2B
2MXN-F03B Primary Bkr Backup Fuse	Ice Condenser Bridge Crane 2 Crane No. R012
2MXN-F03E Primary Bkr Backup Fuse	Stud Tensioner Hoist 2A
2MXN-F04D Primary Bkr Backup Fuse	Lighting Transformer 2LR5
2MXN-F04E Primary Bkr Backup Fuse	Lighting Transformer 2LR6
2MXN-F05A Primary Bkr Backup Fuse	Ice Condenser Refrigeration Floor Cool Defrost Heater 2B
2MXN-F05B Primary Bkr Backup Fuse	Ice Condenser Refrigeration Floor Cool Pump Motor 2B
2MXN-F05C Primary Bkr Backup Fuse	Ice Condenser Equipment Access Door Hoist Motor 2B
2MXN-F06A Primary Bkr	Ice Condenser Air Handling Unit 2B1 Fan Motor A & B

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Backup Fuse	
2MXN-F06B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A2 Fan Motor A & B
2MXN-F06C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B3 Fan Motor A & B
2MXN-F06D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A4 Fan Motor A & B
2MXN-F07B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B5 Fan Motor A & B
2MXN-F07C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A6 Fan Motor A & B
2MXN-F08A Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B7 Fan Motor A & B
2MXN-F08B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A8 Fan Motor A & B
2MXN-F08C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B9 Fan Motor A & B
2MXN-F08D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A10 Fan Motor A & B
2MXN-F09A Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B11 Fan Motor A & B
2MXN-F09B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A12 Fan Motor A & B

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2MXN-F09C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B13 Fan Motor A & B
2MXN-F09D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A14 Fan Motor A & B
2MXN-F10A Primary Bkr Backup Fuse	Cont Floor and Equipment Sump Pump Motor 2A2
2MXN-F10B Primary Bkr Backup Fuse	Cont Floor and Equipment Sump Pump Motor 2B2
2MXN-F10C Primary Bkr Backup Fuse	Incore Instrumentation Sump Pump Motor 2
2MXN-F10D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B15 Fan Motor A & B
2MXO-F01A Primary Bkr Backup Fuse	Upper Cont Air Return Fan Motor 2C
2MXO-F02B Primary Bkr Backup Fuse	Control Rod Drive Ventilation Fan Motor 2A
2MXO-F03A Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 2C Fan Motor
2MXO-F04C Primary Bkr Backup Fuse	Upper Cont Ventilation Unit 2C Fan Motor
2MXO-F05C Primary Bkr Backup Fuse	Cont Pipe Tunnel Booster Fan Motor 2A

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2MXP-F01A Primary Bkr Backup Fuse	Upper Cont Return Air Fan 2B
2MXP-F02B Primary Bkr Backup Fuse	Control Rod Drive Ventilation Fan Motor 2B
2MXP-F03A Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 2B Fan Motor
2MXP-F04D Primary Bkr Backup Fuse	Upper Cont Ventilation Unit 2B Fan Motor
2MXP-F05C Primary Bkr Backup Fuse	Cont Pipe Tunnel Booster Fan Motor 2B
2MXQ-F01A Primary Bkr Backup Fuse	Upper Cont Return Air Fan Motor 2A
2MXQ-F01B Primary Bkr Backup Fuse	Incore Instrument Room Ventilation Unit 2A Fan Motor
2MXQ-F02B Primary Bkr Backup Fuse	Control Rod Drive Ventilation Fan Motor 2C
2MXQ-F03A Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 2A Fan Motor
2MXQ-F04C Primary Bkr Backup Fuse	Upper Cont Ventilation Unit 2A Fan Motor
2MXR-F01A Primary Bkr Backup Fuse	Upper Cont Return Air Fan Motor 2D
2MXR-F01B	Incore Instrument Room Ventilation

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Primary Bkr Backup Fuse	Unit 2B Fan Motor
2MXR-F02B Primary Bkr Backup Fuse	Control Rod Drive Ventilation Fan Motor 2D
2MXR-F03A Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 2D Fan Motor
2MXR-F04C Primary Bkr Backup Fuse	Upper Cont Ventilation Unit 2D Fan Motor
2MXY-F02A Primary Bkr Backup Fuse	NC Pump 2A Oil Lift Pump Motor 1
2MXY-F02B Primary Bkr Backup Fuse	NC Pump 2D Oil Lift Pump Motor 1
2MXY-F02C Primary Bkr Backup Fuse	Rx Bldg Lower Cont Welding Machine Receptacle 2RCPL0185
2MXY-F02D Primary Bkr Backup Fuse	Upper Cont Rx Bldg Welding Receptacle 2RCPL0193
2MXY-F03A Primary Bkr Backup Fuse	Reactor Coolant Drain Tnk Pump Motor 2A
2MXY-F03D Primary Bkr Backup Fuse	Ice Condenser Refrigeration Floor Cool Pump Motor 2A
2MXY-F05A Primary Bkr Backup Fuse	Lighting Transformer 2LR8
2MXY-F05B Primary Bkr	Lighting Transformer 2LR11

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Backup Fuse	
2MXY-F05C Primary Bkr Backup Fuse	Lighting Transformer 2LR14
2MXY-F06A Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A5 Fan Motor A & B
2MXY-F06B Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A11 Fan Motor A & B
2MXY-F06C Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2B12 Fan Motor A & B
2MXY-F06D Primary Bkr Backup Fuse	Ice Condenser Air Handling Unit 2A15 Fan Motor A & B
2MXY-F07C Primary Bkr Backup Fuse	Rx Bldg Receptacles 2RCPL0186 and 2RCPL0187
2MXY-F08A Primary Bkr Backup Fuse	Incore Drive Assembly Motor 2A
2MXY-F08B Primary Bkr Backup Fuse	Incore Drive Assembly Motor 2C
2MXY-F08C Primary Bkr Backup Fuse	Incore Drive Assembly Motor 2E
2MXY-F08D Primary Bkr Backup Fuse	Lower Cont Auxiliary Charcoal Filter Unit Fan Motor 2A
2MXZ-F02A Primary Bkr Backup Fuse	NC Pump 2A Oil Lift Pump Motor 2

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2MXZ-F02B Primary Bkr Backup Fuse	NC Pump 2D Oil Lift Pump Motor 2
2MXZ-F03A Primary Bkr Backup Fuse	Reactor Coolant Drain Tnk Pump Motor 2B
2MXZ-F04B Primary Bkr Backup Fuse	Lighting Transformer 2LR1
2MXZ-F04C Primary Bkr Backup Fuse	Lighting Transformer 2LR2
2MXZ-F04D Primary Bkr Backup Fuse	Lighting Transformer 2LR3
2MXZ-F05A Primary Bkr Backup Fuse	Reactor Coolant Pump Jib Hoist No. R023 through R026
2MXZ-F05C Primary Bkr Backup Fuse	Lower Cont Auxiliary Charcoal Filter Unit Fan Motor 2B
2MXZ-F06A Primary Bkr Backup Fuse	Incore Drive Assembly Motor 2B
2MXZ-F06B Primary Bkr Backup Fuse	Incore Drive Assembly Motor 2D
2MXZ-F06C Primary Bkr Backup Fuse	Incore Drive Assembly Motor 2F
2MXZ-F06D Primary Bkr Backup Fuse	Lower Cont Rx Bldg Welding Receptacle 2RCPL0194

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2MXZ-F07B Primary Bkr Backup Fuse	Lighting Transformer 2LR4
2MXZ-F07C Primary Bkr Backup Fuse	5 Ton Jib Crane in Cont Crane No. R006
2MXZ-F07D Primary Bkr Backup Fuse	Reactor Cavity Manipulator Crane No. R008 and R028
2MXZ-F08A Primary Bkr Backup Fuse	S/G Drain Pump Motor 2
2MXZ-F08C Primary Bkr Backup Fuse	15 Ton Equipment Access Hatch Hoist Crane No. R010
2MXZ-F08D Primary Bkr Backup Fuse	Control Rod Drive 2 Ton Jib Hoist Crane No. R018
2MXZ-F08E Primary Bkr Backup Fuse	Reactor Side Fuel Handling Control Console
SMXG-F06B Primary Bkr Backup Fuse	Standby Makeup Pump Drain Isol Vlv 2NV876
SMXG-R05B Primary Bkr Backup Fuse	Pressurizer Heaters 28, 55, and 56
SMXG-F06C Primary Bkr Backup Fuse	Standby Makeup Pump to Seal Water Line Isol Vlv 2NV877
3. 600 VAC Pressurizer Heater Power Panels	
PHP2A-F01A Primary Bkr	Pressurizer Heaters 1, 2, and 22

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Backup Fuse	
PHP2A-F01B Primary Bkr Backup Fuse	Pressurizer Heaters 5, 6, and 27
PHP2A-F01C Primary Bkr Backup Fuse	Pressurizer Heaters 9, 10, and 32
PHP2A-F02C Primary Bkr Backup Fuse	Pressurizer Heaters 11, 12, and 35
PHP2A-F02D Primary Bkr Backup Fuse	Pressurizer Heaters 13, 14, and 37
PHP2A-F02E Primary Bkr Backup Fuse	Pressurizer Heaters 17, 18, and 42
PHP2B-F01B Primary Bkr Backup Fuse	Pressurizer Heaters 26, 53, and 54
PHP2B-F01C Primary Bkr Backup Fuse	Pressurizer Heaters 31, 59, and 60
PHP2B-F02C Primary Bkr Backup Fuse	Pressurizer Heaters 36, 65, and 66
PHP2B-F02D Primary Bkr Backup Fuse	Pressurizer Heaters 21, 41, and 71
PHP2B-F02E Primary Bkr Backup Fuse	Pressurizer Heaters 46, 77, and 78
PHP2C-F01A Primary Bkr Backup Fuse	Pressurizer Heaters 7, 8, and 30

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
PHP2C-F01B Primary Bkr Backup Fuse	Pressurizer Heaters 19, 20, and 45
PHP2C-F01C Primary Bkr Backup Fuse	Pressurizer Heaters 24, 51, and 52
PHP2C-F01D Primary Bkr Backup Fuse	Pressurizer Heaters 29, 57, and 58
PHP2C-F02C Primary Bkr Backup Fuse	Pressurizer Heaters 34, 63, and 64
PHP2C-F02D Primary Bkr Backup Fuse	Pressurizer Heaters 39, 69, and 70
PHP2C-F02E Primary Bkr Backup Fuse	Pressurizer Heaters 44, 74, and 76
PHP2D-F01A Primary Bkr Backup Fuse	Pressurizer Heaters 3, 4, and 25
PHP2D-F01B Primary Bkr Backup Fuse	Pressurizer Heaters 15, 16, and 40
PHP2D-F01C Primary Bkr Backup Fuse	Pressurizer Heaters 23, 49, and 50
PHP2D-F02C Primary Bkr Backup Fuse	Pressurizer Heaters 33, 61, and 62
PHP2D-F02D Primary Bkr Backup Fuse	Pressurizer Heaters 38, 67, and 68

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION		SYSTEM POWERED
	PHP2D-F02E Primary Bkr Backup Fuse	Spare
4.	250 VDC Reactor Building Deadlight Panelboard	
	2DLD-2 Primary Bkr Backup Fuse	Lighting Panelboard No. 2LR1, 2LR2, 2LR3, 2LR4
	2DLD-3 Primary Bkr Backup Fuse	Lighting Panelboard No. 2LR13, 2LR14
	2DLD-4 Primary Bkr Backup Fuse	Lighting Panelboard No. 2LR5, 2LR6
	2DLD-5 Primary Bkr Backup Fuse	Lighting Panelboard No. 2LR10, 2LR11
	2DLD-10 Primary Bkr Backup Fuse	Lighting Panelboard No. 2LR8
5.	120 VAC Panelboards	
	2ELB-5 Primary Bkr Backup Fuse	Emergency AC Lighting
	2ELB-7 Primary Bkr Backup Fuse	Emergency AC Lighting
	2ELB-13 Primary Bkr Backup Fuse	Emergency AC Lighting
	2ELB-15 Primary Bkr Backup Fuse	Emergency AC Lighting

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
2ELB-17 Primary Bkr Backup Fuse	Emergency AC Lighting
2KPM-1 Primary Bkr Backup Fuse	NC Pump Motor 2A Space Heater
2KPM-2 Primary Bkr Backup Fuse	NC Pump Motor 2C Space Heater
2KPM-7-1 Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 2A Fan Motor Space Heater
2KPM-8-1 Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 2C Fan Motor Space Heater
2KPM-24 Primary Bkr Backup Fuse	Control Rod Drive Ventilation Fan Motor 2A, 2B, 2C, 2D Space Heaters
2KPM-24-10 Primary Fuse Backup Fuse	Control Rod Drive Ventilation Fan Motor 2A Space Heaters
2KPM-24-11 Primary Fuse Backup Fuse	Control Rod Drive Ventilation Fan Motor 2B Space Heaters
2KPM-24-12 Primary Fuse Backup Fuse	Control Rod Drive Ventilation Fan Motor 2C Space Heaters
2KPM-24-13 Primary Fuse Backup Fuse	Control Rod Drive Ventilation Fan Motor 2D Space Heaters
2KPM-33 Primary Bkr Backup Fuse	NI Temperature Transmitters 2NITT5800, 2NITT5810, 2NITT5820, 2NITT5830
2KPM-33-06	NI Temperature Transmitter

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION	SYSTEM POWERED
Primary Fuse	2NITT5800
2KPM-33-07 Primary Fuse	NI Temperature Transmitter 2NITT5810
2KPM-33-08 Primary Fuse	NI Temperature Transmitter 2NITT5820
2KPM-33-09 Primary Fuse	NI Temperature Transmitter 2NITT5830
2KPN-1 Primary Bkr Backup Fuse	NC Pump Motor 2B Space Heater
2KPN-2 Primary Bkr Backup Fuse	NC Pump Motor 2D Space Heater
2KPN-7-1 Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 2B Fan Motor Space Heater
2KPN-08 Primary Bkr Backup Fuse	Lower Cont Ventilation Unit 2D Fan Motor Space Heater, NC Pump Seal Standpipe Vent and Drain Vlvs 2NV105, 2NV106, 2NV110, 2NV111, 2NV115, 2NV116, 2NV120, 2NV121
2KPN-08-01 Primary Fuse Backup Fuse	Lower Cont Ventilation Unit 2D Fan Motor Space Heater
2KPN-08-02 Primary Fuse Backup Fuse	NC Pump 2A Standpipe Drain and Overflow Vlvs 2NV105 and 2NV106
2KPN-08-03 Primary Fuse Backup Fuse	NC Pump 2B Standpipe Drain and Overflow Vlvs 2NV110 and 2NV111
2KPN-08-04 Primary Fuse Backup Fuse	NC Pump 2C Standpipe Drain and Overflow Vlvs 2NV115 and 2NV116

Table 16.8-1-2
Unit 2 CPCOPDs

DEVICE NUMBER AND LOCATION		SYSTEM POWERED
	2KPN-08-05 Primary Fuse Backup Fuse	NC Pump 2D Standpipe Drain and Overflow Vlvs 2NV120 and 2NV121
	2KPN-11 Primary Bkr Backup Fuse	Misc Control Power for 2ATC24
6.	DC Welding Circuits	
	2EQCB0001 Primary Bkr – AA Backup Bkr – AB	Spare
	2EQCB0002 Primary Bkr – AA Backup Bkr – AB	Spare

16.10 STEAM AND POWER CONVERSION SYSTEM

16.10-4 Motor Driven Auxiliary Feedwater Pump Pit (WL) Sump Pumps

COMMITMENT The following Liquid Radwaste (WL) sump pumps in the Auxiliary Feedwater (CA) pump pits shall be FUNCTIONAL on the associated Unit to support the associated Motor Driven CA pump operability.

- Motor Driven CA Pump A sump pump
- Motor Driven CA Pump B sump pump

APPLICABILITY: MODES 1, 2, 3,
MODE 4 when steam generators are relied upon for heat removal.

REMEDIAL ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. COMMITMENT not met.	A.1 Declare the associated Motor Driven CA pump inoperable.	Immediately

TESTING REQUIREMENTS

TEST		FREQUENCY
TR 16.10-4-1	Verify each sump pump's flow rate is greater than or equal to the required flow rate.	In Accordance with the INSERVICE TEST PROGRAM

BASES

The Motor Driven CA pump (MDCAP) pit sump pumps are safety related components with the design basis to prevent flooding in their respective pit. Flooding in the MDCAP sump could render the MDCAP incapable of performing its required safety function. To ensure each MDCAP maintains this capability, each MDCAP pit sump pump is required to be functional. See Reference 3, CNC-1223.42-00-0089, Evaluation of Doghouse Flood on Motor Driven CA Pump Operability, for a detailed analysis.

TR 16.10-4-1 verifies the CA Motor Driven Sump Pumps start on High level and deliver >50 gpm flow in accordance with Reference 3, 4 and 5. The In-Service Testing also monitors component vibration and forward and reverse flow through check valves in the discharge flowpath.

REFERENCES

1. Catawba Updated Final Safety Analysis Report
   a. Section 11.2.2.2.4.4, Auxiliary Feedwater Pump Pit Sumps
   b. Section 11.2.2.2.5.7, Auxiliary Feedwater Pump Pit Sump Pumps
   c. Section 7.6.6, Liquid Radwaste System
   d. Section 10.4.9, Auxiliary Feedwater System

2. CNC-1206.03-00-0001, Flood Levels For Structures outside the Reactor Building, Appendix E, Revision 26.

3. CNC-1223.42-00-0089, Evaluation of Doghouse Flood on Motor Driven CA pump Operability.

4. CNTC-1565-WL-P017-01, Motor Driven Auxiliary Feedwater Sump Pumps.

5. CNTC-2565-WL-P007-01, Motor Driven Auxiliary Feedwater Sump Pumps.

6. PT/1(2)/A/4700/020, WL/WN Sump Pumps and Check Valves Inservice Test.

16.10 STEAM AND POWER CONVERSION SYSTEM

16.10-5 Auxiliary Feedwater Turbine Driven Pump Pit (WL) Sump Pumps

COMMITMENT The following Liquid Radwaste (WL) sump pumps in the Turbine Driven Auxiliary Feedwater (CA) pump pit shall be FUNCTIONAL on the associated Unit to support the associated Turbine Driven CA pump operability.

- Turbine Driven CA Pump A sump pump
- Turbine Driven CA Pump B sump pump

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

REMEDIAL ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One of the two required CAPT Sump Pumps is not functional.	A.1 Apply TS 3.7.5 action B for the associated train. *	Immediately
B. One of the two required CAPT Sump Pumps is not functional. <u>AND</u> The opposite train EDG on the affected Unit is inoperable.	B.1 Apply TS 3.7.5 action C for two AFW trains inoperable.	4 hours following concurrent non functionality of a CAPT sump pump and inoperability of the opposite train EDG (per TS 3.8.1 required action B.3)
C. Both required CAPT Sump Pumps are not functional.	C.1 Declare the CAPT inoperable per the applicable condition of LCO 3.7.5.	Immediately
D. ‘A’ train CAPT sump pump not functional.	D.1 Apply SLC 16.7-9 Condition A.	Immediately

* If a MDCAP is concurrently inoperable per LCO 3.7.5, this condition introduces no further inoperability (e.g. one CAPT sump pump not functional with one of the MDCAP's inoperable does NOT require entry into LCO 3.7.5 Condition C).

TESTING REQUIREMENTS

TEST		FREQUENCY
TR 16.10-5-1	Verify each sump pump's flow rate is greater than or equal to the required flow rate.	In Accordance with the INSERVICE TEST PROGRAM

BASES

The CAPT Sump Pumps are safety related components with the design basis to prevent flooding of the CAPT sump. Flooding in the CAPT sump could render the CAPT incapable of performing its required safety function. To ensure the CAPT maintains this capability, at least one of the two CAPT sump pumps must be maintained functional.

Furthermore, independence must be maintained between the CAPT and the two (2) Motor Driven CA Pumps (MDCAP) such that failure of a single plant component cannot render both a MDCAP and the CAPT Inoperable simultaneously (assuming loss of non-emergency offsite power and a CA autostart). If only one of the two CAPT sump pumps is functional, the failure of a single EDG to start could prevent both the CAPT and MDCAP associated with the failed EDG from performing their required safety functions. The CAPT would be flooded by its lube oil cooler sump input. Therefore, two CAPT sump pumps are required functional to support the operability of the CAPT with respect to Technical Specification 3.7.5.

The CAPT provides residual heat removal during an SSF event. The unit related A train CAPT sump pump is powered from EMXS on the respective unit which can be powered from the SSF. Therefore, the A train CAPT sump pump is required to support Standby Shutdown System (SSS) per SLC 16.7-9.

TR 16.10-5-1 verifies the CAPT pit sump pumps start on high level and deliver >50 gpm flow in accordance with Reference 3, 4, and 5.

Examples:
If the CAPT sump pump "A" is not functional, a single failure of "B" DG coincident with a LOOP, would render both the "B" motor-driven CA pump and CAPT sump pump "B" inoperative. Since both CAPT sump pumps are now inoperable, the CAPT will become flooded within hours due to lube oil cooler input and potential input from doghouse flooding due to a feedline break, along with motor-driven CA pump "B". Therefore, if either of the CAPT sump pumps is inoperable, Catawba ITS 3.7.5 is not satisfied since single failure criteria cannot be met and thus, the ACTION statement for one CA pump inoperable shall be entered (ACTION B).

If a motor-driven CA pump and either of the CAPT sump pumps are non-

BASES (continued)

functional, ACTION B still applies since two independent CA pumps are still considered to be Operable. This is because the additional failure of an emergency diesel generator (DG) need not be considered while operating within the restrictions of the 72 hour ACTION statement.

Similarly, if an emergency diesel generator (DG) is inoperable and the CAPT sump pump of the same train is non functional, then the CAPT may be considered Operable for the purpose of satisfying ACTION B.

Finally, if a CAPT sump pump is not functional and the opposite DG is inoperable, then ITS 3.7.5 ACTION C applies and the Required Action is to be in Mode 3 in 6 hours. However, Required Actions A.2. and B.3. of ITS 3.8.1 also apply to this situation. Condition A applies when an offsite circuit is Inoperable. Condition B applies when an onsite DG circuit is Inoperable. The CAPT sump pumps must be considered "required redundant features" and per Required Action B.3., the sump pump with the Inoperable DG must be declared non-functional 4 hours from discovery of the DG being Inoperable. Per the Bases Section 3.8.1 (B.3), discovering one required DG Inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with the Operable DG, results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is Acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown. In this Condition, the remaining Operable DG and Operable offsite circuits are adequate to supply the remaining CAPT sump pump. Thus, 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 Operability of the redundant counterpart to the Inoperable required feature, as well as the capacity/capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a OBA occurring during this period.

Per ITS 3.8.1 Condition G, the Inoperability of both DGs results in a 2-hour Completion time to return one DG to Operable status, and subsequent entry to ITS 3.0.3. ITS 3.7.5 Condition D for three CA trains in Modes 1, 2 or 3 results in suspension of 3.0.3 and all other LCO required Actions requiring Mode changes. The CAPT sump pumps, while support components for the CAPT, do not render it Inoperable since they can be powered by onsite circuits. Therefore, the suspension of 3.0.3 does not apply if the CAPT is Operable but both DGs are Inoperable.

TR 16.10-5-1 verifies the CA Turbine Driven Sump Pumps start on High level and delivers >50 gpm flow in accordance with Reference 1b, 4 and 5. The In-Service Testing also monitors component vibration and forward and reverse flow through check valves in the discharge flowpath.

REFERENCES

1. Catawba Updated Final Safety Analysis Report
   a. Section 11.2.2.2.4.4, Auxiliary Feedwater Pump Pit Sumps
   b. Section 11.2.2.2.5.7, Auxiliary Feedwater Pump Pit Sump Pumps
   c. Section 7.6.6, Liquid Radwaste System
   d. Section 10.4.9, Auxiliary Feedwater System

2. CNC-1223.42-00-0089, Evaluation of Doghouse Flood on Motor Driven CA pump Operability.

3. Technical Specifications
   a. 3.7.5, Auxiliary Feedwater (AFW) System
   b. 3.8.1, AC Sources Operating
   c. 3.8.9, Distribution Systems Operating

4. CNTC-1565-WL-P016-01, Steam Turbine Driven Auxiliary Feedwater Sump Pumps.

5. CNTC-2565-WL-P006-01, Steam Turbine Driven Auxiliary Feedwater Sump Pumps.

6. CNC-1223.42-00-0080, Determination of CATDP Operating Duration Before Flooding From Normal Sump Inputs Leads to Pump Failure as Result of an ELAP.

7. CNC-1223.15-00-0022, Orifice Sizing for Doghouse Drains.

16.11 RADIOLOGICAL EFFLUENTS CONTROLS

16.11-2 Radioactive Liquid Effluent Monitoring Instrumentation

COMMITMENT

The Radioactive Liquid Effluent Monitoring Instrumentation channels shown in Table 16.11-2-1 shall be FUNCTIONAL with their Alarm/Trip Setpoints set to ensure that the limits of SLC 16.11-1 are not exceeded.

AND

The Alarm/Trip Setpoints of these channels shall be determined and adjusted in accordance with the methodology and parameters in the OFFSITE DOSE CALCULATION MANUAL (ODCM).

APPLICABILITY:

Conditions A, B, and G are applicable at all times. Conditions C, D, E, and F are applicable at all times, except when the effluent pathway is mechanically isolated; thus a release to the environment is not possible.

REMEDIAL ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Radioactive Liquid Effluent Monitoring Instrumentation channel(s) Alarm/Trip Setpoint less conservative than required.	A.1 Suspend the release of radioactive liquid effluents monitored by the affected channel(s).	Immediately
	<u>OR</u>	
	A.2 Declare the channel(s) non-functional.	Immediately
B. One or more Radioactive Liquid Effluent Monitoring Instrumentation channel(s) non-functional.	B.1 Enter the applicable Conditions and Required Actions specified in Table 16.11-2-1 for the channel(s).	Immediately
	<u>AND</u>	
	B.2.1 Restore channel to FUNCTIONAL status.	14 Days (*Note 1)
	<u>OR</u>	
	B.2.2 Restore channel to FUNCTIONAL status.	30 Days (*Note 1)

*Note 1 – Required Action B.2.1 Applies to Instruments 1.a and 1.c ONLY. Required Action B.2.2 Applies to the remainder of required Instruments listed in Table 16.11-2-1.

(continued)

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One channel non-functional.	C.1.1 Analyze two independent samples per Testing Requirement 16.11-1-1.	Prior to initiating a release
	<u>AND</u>	
	C.1.2 Perform independent verification of the discharge line valving.	Prior to initiating a release
	<u>AND</u>	
	C.1.3.1 Perform independent verification of manual portion of the computer input for release rate calculations performed by computer.	Prior to initiating a release
	<u>OR</u>	
	C.1.3.2 Perform independent verification of entire calculations for release rate calculations performed manually.	Prior to initiating a release
	<u>OR</u>	
	C.2 Suspend release of radioactive effluents via this pathway.	Immediately

(continued)

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One flow rate measurement device channel non-functional.	D.1 --------------NOTE------------- Pump performance curves generated in place may be used to estimate flow. ----------------------------------- Estimate the flow rate of the release.	 Once per 4 hours during releases
E. One channel non-functional.	E.1 Perform an analysis of grab samples for radioactivity at a lower limit of detection of 10^{-7} microCurie/ml.	Once per 12 hours during releases when secondary specific activity is > 0.01 microCurie/gm DOSE EQUIVALENT I-131 AND Once per 24 hours during releases when secondary specific activity is ≤ 0.01 microCurie/gm DOSE EQUIVALENT I-131

(continued)

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One channel non-functional.	F.1 Collect and analyze grab samples for principal gamma emitters (listed in Table 16.11-1-1, NOTE 3) at a lower limit of detection of no more than 5×10^{-7} microCurie/ml.	Once per 12 hours
G. Required Action and associated Completion Time of Condition B not met.	G.1 Explain why the non-functionality was not corrected within the specified Completion Time.	In the next scheduled Radioactive Effluent Release Report pursuant to Technical Specification 5.6.3

TESTING REQUIREMENTS

---NOTE---
Refer to Table 16.11-2-1 to determine which TRs apply for each Radioactive Liquid Effluent Monitoring Instrumentation channel.

TEST		FREQUENCY
TR 16.11-2-1	Perform CHANNEL CHECK.	24 hours
TR 16.11-2-2	--------------------------------NOTE-------------------------------- The CHANNEL CHECK shall consist of verifying indication of flow. -- Perform CHANNEL CHECK.	 24 hours during periods of release
TR 16.11-2-3	Perform SOURCE CHECK.	Prior to each release
TR 16.11-2-4	Perform SOURCE CHECK.	31 days
TR 16.11-2-5	Perform COT.	182 days
TR 16.11-2-6	--------------------------------NOTE-------------------------------- For Instrument 1, the COT shall also demonstrate that automatic isolation of this pathway and control room alarm annunciation (for EMF-57, alarm annunciation is in the Monitor Tank Building control room and on the Monitor Tank Building control panel remote annunciator panel) occur if any of the following conditions exist: a. Instrument indicates measured levels above the Alarm/Trip Setpoint, or b. Circuit failure/instrument downscale failure (alarm only) -- Perform COT.	 9 months

(continued)

TESTING REQUIREMENTS (continued)

	TEST	FREQUENCY
TR 16.11-2-7	--------------------------------NOTE-------------------------------- For Instrument 1, the initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards (NBS) or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used. -- Perform CHANNEL CALIBRATION.	18 months

Table 16.11-2-1

Radioactive Liquid Effluent Monitoring Instrumentation

INSTRUMENT	REQUIRED CHANNELS	CONDITIONS	TESTING REQUIREMENTS
1. Radioactivity Monitors Providing Alarm and Automatic Termination of Release			
1.a Waste Liquid Discharge Monitor (EMF-49 – Low Range)	1 per station	A, B, C, G	TR 16.11-2-1 TR 16.11-2-3 TR 16.11-2-6 TR 16.11-2-7
1.b Turbine Building Sump Monitor (EMF-31)	1	A, B, E, G	TR 16.11-2-1 TR 16.11-2-4 TR 16.11-2-6 TR 16.11-2-7
1.c Monitor Tank Building Liquid Discharge Monitor (EMF-57 – Low Range)	1 per station	A, B, C, G	TR 16.11-2-1 TR 16.11-2-3 TR 16.11-2-6 TR 16.11-2-7
2. Continuous Composite Samplers and Sampler Flow Monitor			
2.a Conventional Waste Water Treatment Line (no alarm/trip function)	1 per station	B, E, G	TR 16.11-2-2 TR 16.11-2-7
3. Flow Rate Measurement Devices			
3.a Waste Liquid Effluent Line (no alarm/trip function)	1 per station	B, D, G	TR 16.11-2-2 TR 16.11-2-7
3.b Conventional Waste Water Treatment Line (no alarm/trip function)	1 per station	B, D, G	TR 16.11-2-2 TR 16.11-2-7
3.c Low Pressure Service Water Minimum Flow Interlock	1 per station	B, D, G	TR 16.11-2-2 TR 16.11-2-5 TR 16.11-2-7
3.d Monitor Tank Building Waste Liquid Effluent Line (no alarm/trip function)	1 per station	B, D, G	TR 16.11-2-2 TR 16.11-2-7
4. Radioactivity Monitors Providing Alarm			
4.a Service Water Monitor on Containment Spray Heat Exchanger (EMF-45 A & B – Low Range)	1 per heat exchanger	A, B, F, G	TR 16.11-2-1 TR 16.11-2-4 TR 16.11-2-6 TR 16.11-2-7

BASES

The Radioactive Liquid Effluent Monitoring Instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in liquid effluents during actual or potential releases of liquid effluents. The Alarm/Trip Setpoints for these instruments shall be calculated and adjusted in accordance with the methodology and parameters in the ODCM to ensure that the Alarm/Trip will occur prior to exceeding the limits of 10 CFR Part 20. The FUNCTIONALITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63, and 64 of Appendix A to 10 CFR Part 50.

Regarding the COMMITMENT APPLICABILITY, isolation of the effluent pathway is to be by mechanical means (e.g., valve closure). Electrical or pneumatic isolation is not required, unless the isolation is designed to receive an automatic signal to open.

REFERENCES

1. Catawba Offsite Dose Calculation Manual.

2. 10 CFR Part 20.

3. 10 CFR Part 50, Appendix A.

16.11 RADIOLOGICAL EFFLUENTS CONTROLS

16.11-7 Radioactive Gaseous Effluent Monitoring Instrumentation

COMMITMENT The Radioactive Gaseous Effluent Monitoring Instrumentation channels shown in Table 16.11-7-1 shall be FUNCTIONAL with their Alarm/Trip Setpoints set to ensure that the limits of SLC 16.11-6 are not exceeded.

AND

The Alarm/Trip Setpoints of these channels shall be determined and adjusted in accordance with the methodology and parameters in the OFFSITE DOSE CALCULATION MANUAL (ODCM).

APPLICABILITY: Conditions B and K are applicable at all times. All other Conditions are applicable as shown in Table 16.11-7-1.

REMEDIAL ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Radioactive Gaseous Effluent Monitoring Instrumentation channel(s) Alarm/Trip Setpoint less conservative than required.	A.1 Suspend the release of radioactive gaseous effluents monitored by the affected channel(s).	Immediately
	<u>OR</u>	
	A.2 Declare the channel(s) non-functional.	Immediately
B. One or more Radioactive Gaseous Effluent Monitoring Instrumentation channel(s) non-functional.	B.1 Enter the applicable Conditions and Required Actions specified in Table 16.11-7-1 for the channel(s).	Immediately
	<u>AND</u>	
	B.2.1 Restore channel to FUNCTIONAL status.	14 Days (*Note 1)
	<u>OR</u>	
	B.2.2 Restore channel to FUNCTIONAL status.	30 Days (*Note 1)

*Note 1 – Required Action B.2.1 applies to Instrument 1.a ONLY. (continued)
Required Action B.2.2 applies to Instruments 1.b, 2, 3.a, 3.c, 3.d, 3.e, 5, 6.a, and 6.b listed in Table 16.11-7-1.

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One channel non-functional.	C.1 Verify that EMF-36 (Low Range) is FUNCTIONAL.	Prior to initiating a release
	<u>OR</u>	
	C.2.1 Analyze two independent samples of the tank's contents.	Prior to initiating a release
	<u>AND</u>	
	C.2.2 Perform independent verification of the discharge line valving.	Prior to initiating a release
	<u>AND</u>	
	C.2.3.1 Perform independent verification of manual portion of the computer input for release rate calculations performed by computer.	Prior to initiating a release
	<u>OR</u>	
	C.2.3.2 Perform independent verification of entire calculations for release rate calculations performed manually.	Prior to initiating a release
	<u>OR</u>	
	C.3 Suspend release of radioactive effluents via this pathway.	Immediately

(continued)

REMEDIAL ACTIONS (continued)

CONDITION		REQUIRED ACTION		COMPLETION TIME
D.	One or more flow rate measurement device channel(s) non-functional.	D.1	Estimate the flow rate of the release.	Once per 4 hours during releases
E.	One or more Noble Gas Activity Monitor channel(s) non-functional.	------------------NOTE------------------ **IF** 0EMF41 is NON-FUNCTIONAL **AND** either 1EMF36 **OR** 2EMF36 is NON-FUNCTIONAL, perform SLC 16.7-10, Required Action G.2 --		
		E.1	Obtain grab samples from effluent pathway.	Once per 12 hours during releases
		AND		
		E.2	Perform an analysis of grab samples for radioactivity.	Within 24 hours of obtaining the sample

(continued)

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Noble Gas Activity Monitor (EMF-39 – Low Range) providing automatic termination of release via the Containment Purge Exhaust System (CPES) non-functional.	F.1 -------------NOTE-------------- In order to utilize Required Action F.1, the following conditions must be satisfied: 1. The affected unit is in MODES 5 or 6. 2. EMF-36 is FUNCTIONAL and in service for the affected unit. 3. The Reactor Coolant System for the affected unit has been vented. 4. Either the reactor vessel head is in place (bolts are not required), or if it is not in place, the lifting of heavy loads over the reactor vessel and the movement of irradiated fuel assemblies within containment have been suspended. ------------------------------------ Restore the non-functional channel to FUNCTIONAL status.	 12 hours
G. Required Action and associated Completion Time of Condition F not met. OR Required Action F.1 not utilized.	G.1 Suspend PURGING of radioactive effluents via this pathway.	Immediately

(continued)

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. One or more sampler channel(s) non-functional.	H.1 Perform sampling with auxiliary sampling equipment as required by Table 16.11-6-1.	Continuously
I. One Condenser Evacuation System Noble Gas Activity Monitor (EMF-33) channel non-functional.	I.1 --------------NOTE------------- Applicable to effluent releases via the Condenser Steam Air Ejector (ZJ) System. ------------------------------------ Obtain grab samples from effluent pathway.	Once per 12 hours during releases
	<u>AND</u>	
	I.2 --------------NOTE------------- Applicable to effluent releases via the Condenser Steam Air Ejector (ZJ) System. ------------------------------------ Perform an analysis of grab samples for radioactivity.	Within 24 hours of obtaining the sample
	<u>AND</u>	
		(continued)

REMEDIAL ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. (continued)	I.3 --------------NOTE------------- Applicable to effluent releases via the Steam Generator Blowdown (BB) System atmospheric vent valve (BB-27) in the off-normal mode. ------------------------------------ Perform an analysis of grab samples for radioactivity at a lower limit of detection of 10^{-7} microCurie/ml.	Once per 12 hours during releases when secondary specific activity is > 0.01 microCurie/gm DOSE EQUIVALENT I-131 <u>AND</u> Once per 24 hours during releases when secondary specific activity is ≤ 0.01 microCurie/gm DOSE EQUIVALENT I-131
J. Noble Gas Activity Monitor (EMF-39 – Low Range) providing automatic termination of release via the Containment Air Release and Addition System non-functional.	J.1 Verify that EMF-36 is FUNCTIONAL. <u>OR</u> J.2.1 Analyze two independent samples of the containment atmosphere. <u>AND</u>	Prior to initiating a release Prior to initiating a release (continued)

REMEDIAL ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
J. (continued)	J.2.2 Perform independent verification of the discharge line valving.	Prior to initiating a release
	AND	
	J.2.3.1 Perform independent verification of manual portion of the computer input for release rate calculations performed by computer.	Prior to initiating a release
	OR	
	J.2.3.2 Perform independent verification of entire calculations for release rate calculations performed manually.	Prior to initiating a release

(continued)

REMEDIAL ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
K. Required Action and associated Completion Time of Condition B or F not met.	K.1 Explain why the non-functionality was not corrected within the specified Completion Time.	In the next scheduled Radioactive Effluent Release Report pursuant to Technical Specification 5.6.3

TESTING REQUIREMENTS

---NOTE---
Refer to Table 16.11-7-1 to determine which TRs apply for each Radioactive Gaseous Effluent Monitoring Instrumentation channel.

TEST		FREQUENCY
TR 16.11-7-1	Perform CHANNEL CHECK.	Prior to each release
TR 16.11-7-2	---------------------------------NOTE-------------------------------- For Instruments 1a, 4, and 5, a SOURCE CHECK for these channels shall be the qualitative assessment of channel response when the channel sensor is exposed to a light-emitting diode. -- Perform SOURCE CHECK.	Prior to each release
TR 16.11-7-3	Perform CHANNEL CHECK.	12 hours
TR 16.11-7-4	Perform CHANNEL CHECK.	24 hours
TR 16.11-7-5	Perform CHANNEL CHECK.	7 days

(continued)

TESTING REQUIREMENTS (continued)

TEST		FREQUENCY
TR 16.11-7-6	---NOTE--- For Instruments 2 and 3a, a SOURCE CHECK for these channels shall be the qualitative assessment of channel response when the channel sensor is exposed to a light-emitting diode. --- Perform SOURCE CHECK.	31 days
TR 16.11-7-7	---NOTE--- For Instruments 1a, 3a, 3c, 5, and 6a, the COT shall also demonstrate, as applicable, that automatic isolation of this pathway and control room alarm annunciation (for EMF-58, alarm annunciation is in the Monitor Tank Building control room and on the Monitor Tank Building control panel remote annunciator panel) occur if any of the following conditions exist: a. Instrument indicates measured levels above the Alarm/Trip Setpoint, or b. Circuit failure/instrument downscale failure (alarm only) --- Perform COT.	9 months
TR 16.11-7-8	---NOTE--- For Instruments 2 and 4, the COT shall also demonstrate that automatic isolation of this pathway and control room alarm annunciation occur if any of the following conditions exist: a. Instrument indicates measured levels above the Alarm/Trip Setpoint, or b. Circuit failure/instrument downscale failure (alarm only) --- Perform COT.	18 months

(continued)

TESTING REQUIREMENTS (continued)

TEST		FREQUENCY
TR 16.11-7-9	----------NOTE---------- For Instruments 1a, 2, 3a, 3c, 4, 5, and 6a, the initial CHANNEL CALIBRATION shall be performed using one or more of the reference standards certified by the National Bureau of Standards (NBS) or using standards that have been obtained from suppliers that participate in measurement assurance activities with NBS. These standards shall permit calibrating the system over its intended range of energy and measurement range. For subsequent CHANNEL CALIBRATION, sources that have been related to the initial calibration shall be used. -------------------- Perform CHANNEL CALIBRATION.	18 months

Table 16.11-7-1

Radioactive Gaseous Effluent Monitoring Instrumentation (page 1 of 2)

INSTRUMENT		REQUIRED CHANNELS	CONDITIONS	APPLICABLE MODES	TESTING REQUIREMENTS
1.	Waste Gas Holdup System				
1.a	Noble Gas Activity Monitor – Providing Alarm and Automatic Termination of Release (EMF-50 – Low Range)	1 per station	A, B, C, K	At all times except when the isolation valve is closed and locked	TR 16.11-7-1 TR 16.11-7-2 TR 16.11-7-7 TR 16.11-7-9
1.b	Effluent System Flow Rate Measuring Device	1 per station	B, D, K	At all times except when the isolation valve is closed and locked	TR 16.11-7-1 TR 16.11-7-9
2.	Condenser Evacuation System Noble Gas Activity Monitor (EMF-33) (BB-27 is only isolation function required) (Note 1)	1	A, B, I, K	When air ejectors are in operation (Apply Required Action I.3 when air ejectors are not in operation)	TR 16.11-7-3 TR 16.11-7-6 TR 16.11-7-8 TR 16.11-7-9
3.	Vent System				
3.a	Noble Gas Activity Monitor (EMF-36 – Low Range)	1	A, B, E, K	At all times	TR 16.11-7-4 TR 16.11-7-6 TR 16.11-7-7 TR 16.11-7-9
3.b	Deleted.				
3.c	Particulate Sampler (EMF-35)	1	A, B, H, K	At all times (Note 2)	TR 16.11-7-4 TR 16.11-7-6 TR 16.11-7-7 TR 16.11-7-9
3.d	Unit Vent Stack Flow Rate Meter (no alarm/trip function)	1	B, D, K	At all times (Note 2)	TR 16.11-7-4 TR 16.11-7-9
3.e	Unit Vent Radiation Monitor Flow Meter	1	B, E, K	At all times (Note 2)	TR 16.11-7-4 TR 16.11-7-9
4.	Containment Purge System Noble Gas Activity Monitor – Providing Alarm and Automatic Termination of Release (EMF-39 – Low Range)	1	A, F, G, K	5, 6	TR 16.11-7-2 TR 16.11-7-3 TR 16.11-7-8 TR 16.11-7-9

(continued)

Table 16.11-7-1

Radioactive Gaseous Effluent Monitoring Instrumentation (page 2 of 2)

INSTRUMENT	REQUIRED CHANNELS	CONDITIONS	APPLICABLE MODES	TESTING REQUIREMENTS
5. Containment Air Release and Addition System Noble Gas Activity Monitor – Providing Alarm and Automatic Termination of Release (EMF-39 – Low Range)	1	A, B, J, K	1, 2, 3, 4, 5, 6	TR 16.11-7-2 TR 16.11-7-3 TR 16.11-7-7 TR 16.11-7-9
6. Monitor Tank Building HVAC				
6.a Noble Gas Activity Monitor – Providing Alarm (EMF-58 – Low Range)	1 per station	A, B, E, K	At all times (Note 2)	TR 16.11-7-4 TR 16.11-7-6 TR 16.11-7-7 TR 16.11-7-9
6.b Effluent Flow Rate Measuring Device	1 per station	B, D, K	At all times (Note 2)	TR 16.11-7-4 TR 16.11-7-9

Note 1: The setpoint is as required by the primary to secondary leak rate monitoring program.

Note 2: Except when the effluent pathway is mechanically isolated; thus, a release to the environment is not possible.

BASES

The Radioactive Gaseous Effluent Monitoring Instrumentation is provided to monitor and control, as applicable, the releases of radioactive materials in gaseous effluents during actual or potential releases of gaseous effluents. The Alarm/Trip Setpoints for these instruments shall be calculated in accordance with the methodology and parameters in the ODCM to ensure that the Alarm/Trip will occur prior to exceeding the limits of 10 CFR Part 20. Conservative Alarm/Trip Setpoints may be used during a release provided they are less than or equal to the setpoints determined by the methodology and parameters of the ODCM. The FUNCTIONALITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60, 63, and 64 of Appendix A to 10 CFR Part 50. The sensitivity of any noble gas activity monitor used to show compliance with the gaseous effluent release requirements of SLC 16.11-8 shall be such that concentrations as low as 1×10^{-6} μCi/cc are measurable.

Regarding Note 2 of Table 16.11-7-1, isolation of the effluent pathway is to be by mechanical means (e.g., valve closure). Electrical or pneumatic isolation is not required, unless the isolation is designed to receive an automatic signal to open.

In MODES 5 and 6, initiation of the Containment Purge Exhaust System (CPES) with EMF-39 non-functional is not permissible. The basis for Required Action F.1 is to allow the continued operation of the CPES with EMF-39 initially FUNCTIONAL. Continued operation of the CPES is contingent upon the ability of the affected unit to meet the requirements as noted in Required Action F.1.

TR 16.11-7-7 requires the performance of a COT on the applicable Radioactive Gaseous Effluent Radiation Monitors. The test ensures that a signal from the control room module can generate the appropriate alarm and actuations. The required actuations/isolations for a High Radiation condition (i.e., radiation level above its Trip 2 setpoint) are listed below for each monitor.

0EMF-50 - Waste Gas Discharge Monitor
1WG160 closes when EMF-50 detects radiation level above its setpoint.

1/2EMF-36 - Unit Vent Noble Gas Monitor
The following actuations occur when EMF-36 detects radiation level above its setpoint:

1. Containment Air Release and Addition System fans discharge to unit vent valve VQ10 closes.
2. Auxiliary Building unfiltered ventilation exhaust fans A and B stop.
3. Fuel Handling Ventilation Exhaust System (FHVES) exhaust trains align to the filter units.
4. (For 1EMF-36 only) 1WG160 closes.

1/2EMF-35 - Unit Vent Particulate Monitor (Sampler)
The following actuations occur when EMF-35 detects radiation level above its setpoint:

1. Containment Air Release and Addition System fans discharge to unit vent valve VQ10 closes.
2. Auxiliary Building unfiltered ventilation exhaust fans A and B stop.

BASES (continued)

3. Fuel Handling Ventilation Exhaust System (FHVES) exhaust trains align to the filter units.
4. ((For 1EMF-35 only) 1WG160 closes.

1/2EMF-39 - Containment Noble Gas Monitor
The following actuations occur when EMF-39 detects radiation level above its setpoint:

1. Signals are provided to both trains of the Solid State Protection System (SSPS) to initiate a CPES isolation. This is verified by observing that Relays K615 in the SSPS A output cabinet and the SSPS B output cabinet are latched.
2. EMF-39 isolates the CPES without going through the SSPS by stopping CPES supply fans A and B, CPES exhaust fans A and B, and by closing the appropriate valves and dampers.
3. Containment Evacuation Alarm, unless the source range trip is blocked.

0EMF-58
This monitor provides no control function.

TR 16.11-7-8 requires the performance of a COT on the Condensate Steam Air Ejector Exhaust Monitor, 1/2EMF-33 and Containment Noble Gas Monitor, 1/2EMF-39. The test ensures that a signal from the control room module can generate the appropriate alarm and actuations. The required actuations/isolations for a High Radiation condition (i.e., radiation level above its Trip 2 setpoint) are listed below.

1/2EMF-33 - Condensate Steam Air Ejector Exhaust Monitor
The following actuations occur when EMF-33 detects radiation level above its setpoint:

1. Closure of BB27 is required in order to isolate the Blowdown Tank from the environment. Because of plant limitations/restrictions:
   a. Opening the valve (in order to verify it goes closed on a High Radiation signal) is only possible during outages due to the negative effects on the Blowdown System with the unit at power.
   b. Testing during innages will be by verification of relay contacts opening in the valve circuit.
2. Closure of BB24, BB65, BB69, and BB73 is required to minimize the amount of potentially contaminated material being delivered to the Blowdown Tank.
3. Closure of NM269, NM270, NM271, and NM272 is required to minimize the amount of potentially contaminated material being delivered to the
4. Conventional Sampling System. Closure of NM267 is required to minimize the amount of potentially contaminated material being delivered to the Condensate Storage Tank by isolating flow through EMF-34.
5. Closure of BB48 is required to minimize the amount of potentially contaminated material being delivered from the Blowdown System discharge to the Turbine Building sump.

1/2EMF-39 - Containment Noble Gas Monitor

BASES (continued)

The following actuations occur when EMF-39 detects radiation level above its setpoint:

1. Signals are provided to both trains of the Solid State Protection System (SSPS) to initiate a Containment Air Release and Addition System isolation. This is verified by observing that relays K615 in the SSPS Train A output cabinet and the SSPS Train B output cabinet are latched.
2. Containment Evacuation Alarm, unless the source range trip is blocked.

REFERENCES

1. Catawba Offsite Dose Calculation Manual.

2. 10 CFR Part 20.

16.13 CONDUCT OF OPERATIONS

16.13-4 Minimum Station Staffing Requirements

COMMITMENT Minimum on shift staffing shall be as indicated in Table 16.13-4-1.

APPLICABILITY: According to Table 16.13-4-1.

REMEDIAL ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Minimum station staffing requirements not met.	A.1 Initiate action to fill required positions.	Immediately
	<u>AND</u>	
	A.2 Restore minimum station staffing levels.	2 hours

TESTING REQUIREMENTS

TEST	FREQUENCY
TR 16.13-4-1 Verify on shift staffing levels.	12 hours

Table 16.13-4-1

Minimum Station Staffing Requirements

POSITION	BOTH UNITS IN MODES 1-4	ONE UNIT IN MODES 1-4	BOTH UNITS IN MODES 5, 6, OR NO MODE
Operations Shift Manager (SM)	1	1	1
Shift Technical Advisor (STA)	1	1	1
Senior Reactor Operator (SRO)(1)(2)(3)	2	2	1
Reactor Operator (RO)(1)(4)	3	3	2
Non-Licensed Operator (AO)(1)(6)	5	5	4
Shift Communicator	1	1	1
Fire Brigade Leader(1)	1	1	1
Fire Brigade Member(6)	4	4	4
Chemistry Technician	1	1	1
Radiation Protection Qualified Individual (Note 5)	2	2	2
Mechanical Maintenance Technician	1	1	1
Instrumentation and Electrical Technician	2	2	2
Medical Emergency Response Team (MERT)	2	2	2
Security Personnel	Per Security Plan	Per Security Plan	Per Security Plan

(1) Either a SRO (active or inactive), RO, or other designated personnel (NLO) may be designated as the fire brigade leader. The totals for the appropriate position shall be increased by one, depending upon which position is being used to fulfill the role of fire brigade leader.

(2) In addition to these requirements, during CORE ALTERATIONS (including fuel loading or transfer), a SRO or SRO limited to fuel handling shall be present to directly supervise the activity. During this time, no other duties shall be assigned to this person.

(3) With any unit in MODES 1-4, a SRO shall be present in the control room at all times.

(4) For each fueled unit, a RO shall be present at the controls at all times.

(5) One RP Qualified Individual must meet or exceed RP Technician minimum ANSI qualifications per Technical Specification 5.2.2.d.

(6) Of the 5 required AOs, three are required by TS 5.2.2.a and 2 are required by the fire protection program and SLC 16.13-1 “Fire Brigade”.

BASES

The requirements of this SLC consolidate Catawba station staffing requirements into one document. The bases for the numbers in the first column of Table 16.13-4-1 are as follows:

1 SM (active SRO) – Required by 10 CFR 50.54(m)(2)(ii) and the Fleet Common Emergency Plan.

1 STA – Required by TS 5.2.2g and the Fleet Common Emergency Pan. The STA is assigned collateral ERO functions of Shift Classification Advisor, Shift Dose Assessor and Core/Thermal Hydraulics Engineer.

2 SROs (active SRO) – Required by 10 CFR 50.54(m)(2)(i). Per TS 5.2.2b and 10 CFR 50.54(m)(2)(iii), at least 1 SRO must be in the control room.

3 ROs – Required by 10 CFR 50.54(m)(2)(i).

5 AOs – 3 Required by TS 5.2.2a and 2 required by the Fire Protection Program and SLC 16.13-1, Fire Brigade.

1 Shift Communicator - Required by the Fleet Common Emergency Plan. This position is designated to perform off-site communications during the first 75 minutes following Emergency Class Declaration with no collateral duties. Any off-site communicator qualified individual may be credited towards fulfilling the ERO requirement.

Fire Brigade Leader – Required by SLC 16.13-1, “Fire Brigade.” The individual fulfilling this position shall be a SRO, RO, or other designated personnel (AO) who is qualified to be a fire brigade leader. This individual functions as the fire brigade leader and is not available for other activities when directing the fire brigade. No regulations explicitly specify that the fire brigade leader be a SRO or RO. However, the fire brigade leader shall have sufficient training in or knowledge of plant safety related systems to understand the effects of a fire and fire suppression systems on safe shutdown capability.

4 Fire Brigade Members – Required by SLC 16.13-1, “Fire Brigade”

1 Chemistry Technician– Required by NEI 12-01 Phase 2 Extended Loss of AC Power (ELAP) ERO Staffing Analysis Report. Any technician who is qualified may be credited towards fulfilling the ERO requirement.

2 Radiation Protection Qualified Individuals (ERO) - Required by Section B, Table B-1 of the Emergency Plan. 1 Radiation Protection Technician is required by TS 5.2.2d and may be counted towards fulfilling the ERO requirement. Any RP Qualified Individual may be credited towards fulfilling the ERO requirement. In the event of a fire, the RP Qualified Individual will respond to the fire for radiological monitoring purposes until directed otherwise.

1 Mechanical Maintenance Technician– Required by NEI 12-01 Phase 2 Extended Loss of AC Power (ELAP) ERO Staffing Analysis Report.

2 Instrumentation and Electrical Technicians – Required by NEI 12-01 Phase 2 Extended Loss of AC Power (ELAP) ERO Staffing Analysis Report.

2 MERT– Required by AD-SY-ALL-0280, Medical Emergency Response Team (MERT) and Technical Rescue Programs.

Minimum station staffing totals for the SRO and RO positions in Table 16.13-4-1 are a function of the number of units in MODES 1-4. The totals for the remaining positions in Table 16.13-4-1 are not a function of the operational MODES of the units.

10 CFR 50.54(m)(2)(i) requires 2 active SROs when both units are in MODES 1-4, 2 active SROs when one unit is in MODES 1-4, and 1 active SRO when no units are in MODES 1-4.

10 CFR 50.54(m)(2)(i) requires 3 ROs when both units are in MODES 1-4, 3 ROs when one unit is in MODES 1-4, and 2 ROs when no units are in MODES 1-4.

The primary purpose of the Fire Protection Program is to minimize both the probability and consequence of postulated fires. Despite designed active and passive fire protection systems installed throughout the plant, a properly trained and equipped fire brigade organization of at least 5 members is required to provide immediate response to fires that may occur at the site.

The 2-hour REMEDIAL ACTION for restoring minimum station staffing levels is consistent with TS 5.2.2c and 5.2.2d, which allow 2 hours to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

REFERENCES

1. Catawba Facility Operating Licenses for Units 1 and 2, NPF-35 and NPF-52.
2. Catawba TS 5.2.2.
3. 10 CFR 50.54(m).
4. OMP 1-10, “Shift Manning and Overtime Requirements.”
5. AD-TQ-ALL-0086, "Fire Brigade Training."
6. CNS-1465.00-00-0006, “Plant Design Basis Specification for Fire Protection.”
7. EP-ALL-EPLAN, “Duke Energy Common Emergency Plan,” Rev. 0
8. SLC 16.13-1, “Fire Brigade.”

9. Catawba Nuclear Station 10 CFR 50.48(c) Fire Protection Safety Evaluation (SE).

10. Letter dated 8/26/2021 from Andrew Hon (NRC) to Steve Snider (Duke), Subject: Catawba Nuclear Station, Units 1 and 2; McGuire Nuclear Station, Units 1 and 2; Oconee Nuclear Station, Units 1, 2, and 3; Brunswick Steam Electric Plant, Units 1 and 2, Shearon Harris Nuclear Plant, Unit 1; and H. B. Robinson Steam Electric Plant, Unit No. 2 – Issuance of Amendments for Common Emergency Plan Consistent with NUREG-0654, Revision 2 (EPID L-2020-LLA-0198) ADAMS Accession No. ML21155A213.

11. EP-CNS-EPLAN-ANNEX, “Duke Energy Catawba Emergency Plan Annex,” Rev. 0