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10 CFR 50.71(e)
10 CFR 50.59(d)(2)
10 CFR 72.48(d)(2)
10 CFR 72.70

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

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
DOCKET NO. 50-261 / RENEWED LICENSE NO. DPR-23

H. B. ROBINSON STEAM ELECTRIC PLANT, UNIT NO. 2
INDEPENDENT SPENT FUEL STORAGE INSTALLATION
DOCKET NO. 72-3 / LICENSE NO. SNM-2502

SUBJECT: Submittal of Updated Final Safety Analysis Report (Revision No. 29), Independent Spent Fuel Storage Installation Safety Analysis Report (Revision No. 27), Technical Specifications Bases Revisions, Quality Assurance Program Description, 10 CFR 50.59 Evaluations, 72.48 Evaluations, and Commitment Change

REFERENCES:

1. Duke Energy letter, *Submittal of Updated Final Safety Analysis Report (Revision No. 28), Technical Specifications Bases Revisions, 10 CFR 50.59 Evaluations, 72.48 Evaluations, and Commitment Change*, dated May 28, 2019 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML19155A082)
2. NRC letter, *Shearon Harris Nuclear Power Plant, Unit 1 and H. B. Robinson Steam Electric Plant, Unit No. 2 - Issuance of Amendments Revising Technical Specifications to Support Self-Performance of Core Reload Design and Safety Analyses (EPID L-2017-LLA-0356)*, dated April 29, 2019 (ADAMS Accession No. ML18288A139)
3. NRC letter, *Shearon Harris Nuclear Power Plant, Unit 1 and H. B. Robinson Steam Electric Plant, Unit No. 2 - Issuance of Amendments Revising Technical Specifications for Methodology Reports DPC-NE-3008-P, Revision 0, "Thermal-Hydraulic Models for Transient Analysis," and DPC-NE-3009-P, Revision 0, "FSAR / UFSAR Chapter 15 Transient Analysis Methodology" (CAC NOS. MF8439 and MF8440; EPID L-2016-LLA-0012)*, dated April 10, 2018 (ADAMS Accession No. ML18060A401)
4. NRC letter, *Shearon Harris Nuclear Power Plant, Unit 1 and H. B. Robinson Steam Electric Plant, Unit No. 2 - Issuance of Amendments Revising Technical Specifications for Methodology Reports DPC-NE-1008-P Revision 0, "Nuclear Design Methodology Using CASMO-5/SIMULATE-3 for Westinghouse Reactors," DPC-NF-2010 Revision 3,*

"Nuclear Physics Methodology for Reload Design," and DPC-NE-2011-P Revision 2, "Nuclear Design Methodology Report for Core Operating Limits of Westinghouse Reactors" (CAC NOS. MF6648/MF6649 and MF7693/MF7694), dated May 18, 2017 (ADAMS Accession No. ML17102A923)

5. NRC letter, *Shearon Harris Nuclear Power Plant, Unit 1 and H. B. Robinson Steam Electric Plant, Unit No. 2 - Issuance of Amendments Revising Technical Specifications for Methodology Reports DPC-NE-2005-P, Revision 5, "Thermal-Hydraulic Statistical Core Design Methodology" (CAC NOS. MF5872 AND MF5873)*, dated March 8, 2016 (ADAMS Accession No. ML17102A923)
6. Duke Energy letter, *Submittal of Revision 27 to the Independent Spent Fuel Storage Installation Safety Analysis Report*, dated July 16, 2020 (ADAMS Accession No. ML20198M677 and ML20198M679)

Ladies and Gentlemen:

In accordance with 10 CFR 50.71(e), Duke Energy Progress, LLC (Duke Energy) hereby submits Revision No. 29 to the Updated Final Safety Analysis Report (UFSAR) for the H. B. Robinson Steam Electric Plant (RNP), Unit No. 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 December 9, 2020. The RNP UFSAR is provided in Enclosures 6 and 7. Enclosure 6 provides a copy of the UFSAR that has been redacted for public use. Enclosure 7 provides UFSAR pages that contain sensitive information to be withheld from public disclosure per 10 CFR 2.390(d)(1). Changes made since Revision No. 28 (Reference 1) are identified by vertical lines in the margins of the pages that are indicated as Revision No. 29. The Quality Assurance Program Description, DUKE-QAPD-001, is incorporated by reference into the RNP UFSAR and is provided in Enclosure 5.

By the safety evaluations listed in References 2 through 5, the NRC authorized the use of new fuel analysis methods for RNP. Revision 29 of the RNP UFSAR incorporates changes necessary to reflect use of these methods.

In accordance with 10 CFR 72.70, Duke Energy hereby notifies the NRC that there have been no changes to the Safety Analysis Report (SAR) for the site-specific licensed RNP Independent Spent Fuel Storage Installation (ISFSI) since Revision 27 provided in Reference 6. Therefore, the RNP ISFSI SAR remains as Revision 27 and is not included in this submittal.

In accordance with 10 CFR 50.59(d)(2) and 10 CFR 72.48(d)(2), Duke Energy is providing a report summarizing the 10 CFR 50.59 and 10 CFR 72.48 evaluations of changes, tests, and experiments implemented during the period from May 21, 2019, to May 12, 2021. The 10 CFR 50.59 report is provided in Enclosure 1 and the 10 CFR 72.48 report is provided in Enclosure 2. In addition, in accordance with Duke Energy's commitment management program (i.e., AD-LS-ALL-0010, *Commitment Management*), notification of a regulatory commitment change is provided in Enclosure 3.

Pursuant to Technical Specification (TS) 5.5.14.d, Duke Energy is providing the latest revision of the RNP Technical Specifications Bases. The TS Bases in Enclosure 4 includes those changes (Revisions 81 through 88) that have been incorporated since the last submittal (Reference 1) of the TS Bases.

No new commitments have been made in this submittal. If you have additional questions, please contact Mr. Art Zaremba, Manager – Regulatory Affairs, at 980-373-2062.

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

Executed on May 27, 2021.

Sincerely,

Ernest J. Kapopoulos, Jr.
Site Vice President

Enclosures:

1. Summary of Changes, Tests, and Experiments Requiring 10 CFR 50.59 Evaluations
2. Summary of Changes, Tests, and Experiments Requiring 10 CFR 72.48 Evaluations
3. Regulatory Commitment Change
4. Technical Specifications Bases, Revision 88
5. Quality Assurance Program Description, Amendment 46
6. UFSAR, Revision 29 (Publicly Available Information)
7. UFSAR, Revision 29 (Non-Publicly Available Information)

cc:

L. Dudes, Regional Administrator USNRC Region II
M. Fannon, NRC Senior Resident Inspector
T. Hood, NRR Project Manager
J. Klos, NRR Project Manager

Enclosure 1
Summary of Changes, Tests, and Experiments Requiring 10 CFR 50.59 Evaluations

Summary of 10 CFR 50.59 Evaluations

Title:
Extend Turbine Valve Movement Test

Documentation Number(s):
Action Request (AR) 02373616

Brief Description:
A maintenance optimization strategy for the turbine valves proposes an adjustment to the current turbine valve test intervals. The main turbine stop valves (SVs), governor valves (GVs), reheat stop valves (RSVs), and reheat intercept valves (IVs) are key elements of the turbine Overspeed Protection System (OPS). Their design function is to quickly terminate steam flow to the high pressure (HP) turbine and low pressure (LP) turbines during an overspeed event, limiting the potential for turbine missile generation due to turbine rotor failure. At present, RNP tests the turbine valves every 9 months. The proposed change would extend the testing frequency to 12 months.

The evaluation concluded that the proposed changes to turbine valve testing intervals at RNP can be implemented without prior NRC approval. The proposed change does not impact HBR, Unit 2, Technical Specification (TS) Limiting Conditions for Operation (LCOs) nor TS Surveillance Requirements (SRs). The proposed change and subsequent reduction in turbine valve reliability and its impact on turbine missile generation probability was evaluated. The resulting increase in turbine missile generation probability remains below the plant-specific acceptance limit in the UFSAR. It has been determined that there is no more than a minimal increase in the occurrence of a turbine-generated missile resulting from implementation of the proposed change. With respect to the dose consequences associated with the proposed change, it was noted that radiological consequences are not evaluated for turbine missile generation accidents. Therefore, there are inherently no dose-related impacts associated with the proposed change. The proposed change does not impact the methodology used to develop the turbine missile generation probabilities at HBR, Unit 2. Rather, analysis assessed the impact of the change in reliability of the turbine valves on the existing turbine missile generation probability. Therefore, 50.59 Criterion 8 was deemed not applicable.

Summary of 10 CFR 50.59 Evaluations

Title:
Protective Relay Upgrade

Documentation Number(s):
Action Request (AR) 02360205
Engineering Change (EC) 414969

Brief Description:
This evaluation addresses activities under Engineering Change (EC) 414969 for the replacement of analog protective relaying for the Robinson Unit 2 main generator, generator-transformer (GT), unit auxiliary transformer (UAT) and main (GSU) transformer. In addition to replacing protective functions provided by the analog relay, the digital protective relays provide additional protective functions. This activity does not require a revision or addition to the Technical Specification. This change has been evaluated against the eight (8) questions required by 10CFR50.59. From this evaluation it is concluded that the change can be implemented under 10CFR50.59 without prior approval from the NRC.

Summary of 10 CFR 50.59 Evaluations

Title:
Post-Accident Containment Water Level Transmitter Temporary Change

Documentation Number(s):
Action Request (AR) 02360858
Engineering Change (EC) 418607

Brief Description:
Containment Vessel (CV) Sump Level instrument loop L-802 is being temporarily modified by the proposed change (EC 418607 Post Accident Containment Water Level Transmitter Temporary Change). The sensing element for level instrument loop L-802 is comprised of five (5) level transmitter units. Each transmitter unit measures 84 inches of water level for a total measurement span of 420 inches. Since the current transmitter units start measuring water level at 3.5 inches above the CV Sump floor, the range of the indicated water level is 3.5 inches to 423.5 inches.

The proposed change will bypass the transfer switch function of two of the transmitter units thereby disabling indication of water level within their respective regions of measurement. This will create a dead band in level indication from 87.5 inches to 255.5 inches. The proposed change will also accept an as as-found condition identified in the circuit causing indicated water level to decrease as water level increases in the range of one of the other three transmitter units. The range of reverse indication will be from 255.5 inches to 339.5 inches.

The proposed temporary change has been evaluated per the requirements of 10CFR 50.59. The existing accidents that have been analyzed, which have been determined to be applicable to the proposed change are: Small Break Loss-of-Coolant Accident and Loss-of-Coolant Accident. That evaluation concluded that a dead band in the indication range of instrument loop L-802 would not increase the frequency of occurrence of those accidents, would not increase the occurrence of failure of an SSC important to safety, would not increase the consequences of an accident and would not increase the consequence of an equipment malfunction.

The change in indicated water level has also been determined to not create an accident of a different type or result in equipment malfunctioning in a different way.

The proposed change in indication would not directly or indirectly affect Design Basis Limits for a fission product barrier and changing the indicated water level is not a change in evaluation methodology.

Therefore, it has been concluded that prior NRC approval is not required for implementation of the proposed change.

Summary of 10 CFR 50.59 Evaluations

Title:
Extend Reactor Coolant Pump (RCP) Motor Flywheels Examination Frequency

Documentation Number(s):
Action Request (AR) 02326452

Brief Description:
A maintenance optimization strategy for the Reactor Coolant Pump (RCP) motor flywheels proposes an adjustment to the current flywheel examination frequency. The design function of the RCP motor flywheel is to provide additional inertia that will increase RCP coast down time, thereby reducing the consequences of a loss-of-coolant accident or a decrease in reactor coolant flow caused by loss of power to the RCP motor. At present, RNP performs examinations of the RCP flywheels on site per the RCP Flywheel Inspection Program, which provides controls for the inspection of each RCP motor flywheel in accordance with the Inservice Inspection Program. Specifically, RNP examines the RCP motor flywheels at the first refueling outage after each ten-year examination, at the fourth refueling outage after each ten-year inspection, and during each fourth refueling outage thereafter. These inspections are in addition to those examinations performed at off-site facilities during RCP motor refurbishments. The proposed change would increase the examination frequency to an interval not to exceed 20 years permitting flywheel examinations and RCP motor refurbishments to be conducted concurrently. The technical justification for the examination frequency extension is provided in WCAP-15666, Extension of Reactor Coolant Pump Motor Flywheel Examination, Revision 0, and was approved by the NRC as documented in the Safety Evaluation Report (ML031250595).

The evaluation concluded that the proposed changes to RCP motor flywheel examination intervals at RNP, Unit 2, can be implemented without prior NRC approval. The proposed change does not impact RNP, Unit 2, Technical Specifications (TS) nor TS Surveillance Requirements (SRs). The proposed activity was evaluated and it was concluded there is no adverse impact to the RCP motor flywheel structural integrity. The predominant conclusion justifying negative responses to the evaluation questions was based on the conservative design and operating conditions precluding missile production by the RCP motor flywheels, as evaluated in UFSAR Section 3.5.1.1. As stated in the NRC Safety Evaluation for WCAP-15666, which evaluated the impact of the examination frequency extension: "The potential for failure of the RCP flywheel is, and will continue to be, negligible during normal and accident conditions."

Summary of 10 CFR 50.59 Evaluations

Title:
Aging Management Program (AMP) UFSAR Description (MRP-227 Revision 1-A)

Documentation Number(s):
Action Request (AR) 02318569

Brief Description:
This 50.59 Evaluation addresses the revision to the aging management program (AMP) for PWR Vessel Internals in UFSAR Section 18.1.30, documented under UFSAR Change 17-0002. UFSAR Change 17-0002 describes chronology of PWR Vessel Internals Program development, from the submittal of the program in 2009, to the transition to MRP-227 Revision 1-A. This UFSAR Change also documents compliance with the Actions / Licensee Action Item (A/LAI) necessary to support the transition from MRP-227-A to MRP-227 Revision 1-A.

The 10 CFR 50.59 screen for UFSAR Change 17-0002 determined that changes associated with MRP-227 Revision 1-A constitute a change to evaluation methodology. Specifically, these are:

- Changes to evaluation methodology for control rod guide tube (CRGT) guide cards, and
- Changes to evaluation methods for determining extent and frequency of baffle-former bolt inspections.

Additionally, the screen noted a general discussion on change to evaluation methodologies in the Safety Evaluation documenting NRC's review of MRP-227 Revision 1-A. These items regarding change to evaluation methodologies were determined to require evaluation against the criteria of 10 CFR 50.59. This 50.59 evaluation concluded that use of MRP-227 Revision 1-A, including changes to methods of evaluation, has been approved by the NRC, and that the applicability of MRP-227 Revision 1-A has been established for the RNP PWR Vessel Internals Program as described in UFSAR Change 17-0002.

Summary of 10 CFR 50.59 Evaluations

Title:
Turbine Valve Maintenance Interval and Turbine Missile Generation Probability

Documentation Number(s):
Action Request (AR) 02347712

Brief Description:
Nuclear Condition Report (NCR) 2339849 identified that the turbine missile generation probability listed in Section 3.5.1.3.1.2, Low Pressure Turbine, of the RNP Updated Final Safety Analysis Report (UFSAR) is incorrect due to the recent change (April 2019) to an eight-year (8Y) frequency of the Intercept Valve (IV) and Reheat Stop Valve (RSV) rebuild PMs. This change did not identify that the turbine missile generation probability would be impacted. The proposed change would validate the acceptability of the April 2019 change to an 8Y maintenance interval and correct the turbine missile generation probability, which presently reflects a six-year (6Y) maintenance refurbishment interval for these valves.

The evaluation concluded that the proposed changes to turbine valve maintenance intervals at RNP can be implemented without prior NRC approval. The proposed change does not impact RNP Technical Specification (TS) Limiting Conditions for Operation (LCOs) nor TS Surveillance Requirements (SRs). The proposed change and subsequent reduction in turbine valve reliability and its impact on turbine missile generation probability was evaluated. The resulting increase in turbine missile generation probability remains below the plant-specific acceptance limit in the UFSAR. It has been determined that there is no more than a minimal increase in the occurrence of a turbine-generated missile resulting from implementation of the proposed change. With respect to the dose consequences associated with the proposed change, it was noted that radiological consequences are not evaluated for turbine missile generation accidents. Therefore, there are inherently no dose-related impacts associated with the proposed change. The proposed change does not impact the methodology used to develop the turbine missile generation probabilities at RNP. Rather, analysis assessed the impact of the change in reliability of the turbine valves on the existing turbine missile generation probability. Therefore, 50.59 Criterion 8 was deemed not applicable.

Summary of 10 CFR 50.59 Evaluations

Title:
Robinson 2 Cycle 32 Core Reload Design 50.59 Evaluation - Revision 1

Documentation Number(s):
Action Request (AR) 02311356 (Supersedes AR 02209962)

Brief Description:
Revision 1 of this evaluation is being created to address Nuclear Condition Report (NCR) 02310600 (Error in the UFSAR Chapter 15.1.5 MSLB DNBR results). Revision 0 of this evaluation was AR 02209962.

The core reload design for Robinson 2 Cycle 32 has been examined to determine if an NRC submittal is required per the requirements of 10 CFR 50.59. The cycle specific analyses for Cycle 32 were analyzed for either MDNBR (Minimum Departure from Nucleate Boiling Ratio), FCM (Fuel Center-line Melt), peak pressure, minimum steam generator mass, and/or peak enthalpy and compared to the Cycle 31 (AOR) results. Some analyses had increased margin to the associated limits and some analyses had decreased margin to the associated limits. Since some analyses had reduced margin to the associated limits, there was an adverse effect on the design function of the SSC for these analyses. Thus, these analyzed events with reduced margin associated with the new core design require evaluation. Also, after correcting the statistics, it was determined that a higher, more restrictive (and therefore more conservative) limit than the 1.121 Biasi DNB limit approved by the NRC for main steam line break is more appropriate. Due to the change in the Biasi MDNBR limit, the proposed activity also revises or replaces a method of evaluation described in the UFSAR that is used in establishing the design basis or used in the safety analysis. Therefore, this also required an evaluation because it was an adverse effect on how a UFSAR described design function is performed or controlled and it revises or replaces a methodology. In addition, Framatome determined that the calculated MDNBR using the Biasi correlation was incorrect. The critical heat flux calculation was being calculated with the lumped channel hydraulic diameter instead of the limiting channels hydraulic diameter. This adversely impacted the calculation of MDNBR for all steam line break cases. Therefore, this also required an evaluation.

For the UFSAR Chapter 15 transients without dose analyses none of these analyses with reduced margin result in a violation of their respective MDNBR, FCM, peak pressure, minimum steam generator mass, or peak enthalpy limits. For the transients that allow for fuel failure, transient analysis predicted fuel failures are bounded by the AST dose analysis fuel failure assumptions. Thus, all analyses continue to be within the assumptions of the dose analysis and there is no change to the predicted dose consequences for any accidents. The frequency of occurrence of an accident or likelihood of occurrence of a malfunction of an SSC are also not increased. There is also no possibility for an accident of a different type or malfunction with a different result. Thus, no submittal is required for the reduced margin cases.

The Biasi DNB limit is a design basis limit for a fission product barrier. It is used to assess whether the fuel cladding (a fission product barrier) is breached. Per NEI 96-07 Revision 1, “A new correlation or a new value for the “95/95 DNB criterion” with the same fuel type would be evaluated under criterion (c)(2)(viii) of the rule.” After correcting the statistics which determined the Biasi DNB limit, it was determined that a higher, more restrictive (and therefore more conservative) limit than the 1.121 limit from the NRC approved methodology is more appropriate. The correction to the Biasi DNB limit raises it with no effect on the calculated MDNBR. Despite the loss of margin, there continues to be no fuel cladding rupture in the main

Summary of 10 CFR 50.59 Evaluations

steam line break accident. Per NEI 96-07 Section 4.3.8, the following is not considered a departure from a method of evaluation: Use of a methodology revision that is documented as providing results that are essentially the same as, or more conservative than, either the previous revision of the same methodology or another methodology previously accepted by NRC through issuance of an SER. Requiring a higher Biasi DNB limit than approved by the SER is conservative because the change reduces margin to the fuel cladding rupture as measured by the Biasi DNB correlation. Thus, no submittal is required for the more restrictive Biasi DNB limit.

Both aspects that screened in, the reduced margins and more restrictive Biasi DNB limit, did not require submittal. Therefore, the reload core design does not require submittal to the NRC.

Summary of 10 CFR 50.59 Evaluations

Title:
Update to UFSAR 15.6.3 (RNP Steam Generator Tube Rupture)

Documentation Number(s):
Action Request (AR) 02301943

Brief Description:
An update to Section 15.6.3.2.4 of the Robinson Nuclear Plant (RNP) Updated Final Safety Analysis Report (UFSAR) has been prepared. This section summarizes the dose consequences for the Steam Generator Tube Rupture (SGTR) event. The change in dose consequences is a result of an input change in a parameter that is not described in the UFSAR. The input change delayed the timing of initiation of the emergency mode control room filtration for the accident induced iodine spike scenario of the SGTR. The evaluation determined the proposed activity did not result in more than a minimal increase in consequences, and the UFSAR update does not require prior NRC approval.

Summary of 10 CFR 50.59 Evaluations

Title:
NFPA 805 Switchgear Coordination MCC-10

Documentation Number(s):
Action Request (AR) 02298165
Engineering Change (EC) 415353

Brief Description:
The proposed activity (EC 415353) will replace a molded case circuit breaker (MCCB) located in Motor Control Center (MCC) MCC-5 compartment 17FR with a new breaker. MCC-5 Breaker 17FR is the feeder breaker for MCC-10. MCC-10 supplies various circuits, including circuits related to Auxiliary Feedwater (AFW), Service Water, Instrument Air, Fire Detection and Actuation Panels (FDAP), Battery Room Exhaust Fan, and Loose Parts Monitoring.

The downstream breakers presently do not coordinate properly with the existing feeder breaker in the instantaneous breaker trip region. The new breaker contains an electronic trip unit allowing the breaker time current curve to be adjusted for coordination with downstream breakers. Coordination is required to support the transition to NFPA 805.

The proposed activity was conservatively screened-in due to introduction of a digital device containing software in a safety related SSC and the potential for different failure mechanisms of the digital device when compared to the existing analog device.

The 10 CFR 50.59 Evaluation concludes the proposed change is acceptable to implement without prior NRC approval, and that the proposed change does not require a modification, deletion, or addition to the plant Technical Specifications.

Summary of 10 CFR 50.59 Evaluations

Title:
Extend Turbine Valve Movement Test

Documentation Number(s):
Action Request (AR) 02309990

Brief Description:
A maintenance optimization strategy for the turbine valves proposes an adjustment to the current turbine valve test intervals. The main turbine stop valves (SVs), governor valves (GVs), reheat stop valves (RSVs), and reheat intercept valves (IVs) are key elements of the turbine Overspeed Protection System (OPS). Their design function is to quickly terminate steam flow to the high pressure (HP) turbine and low pressure (LP) turbines during an overspeed event, limiting the potential for turbine missile generation due to turbine rotor failure. At present, RNP tests the turbine valves every 6 months. The proposed change would extend the testing frequency to 9 months.

The evaluation concluded that the proposed changes to turbine valve testing intervals at RNP can be implemented without prior NRC approval. The proposed change does not impact RNP Technical Specification (TS) Limiting Conditions for Operation (LCOs) nor TS Surveillance Requirements (SRs). The proposed change and subsequent reduction in turbine valve reliability and its impact on turbine missile generation probability was evaluated. The resulting increase in turbine missile generation probability remains below the plant-specific acceptance limit in the UFSAR. It has been determined that there is no more than a minimal increase in the occurrence of a turbine-generated missile resulting from implementation of the proposed change. With respect to the dose consequences associated with the proposed change, it was noted that radiological consequences are not evaluated for turbine missile generation accidents. Therefore, there are inherently no dose-related impacts associated with the proposed change. The proposed change does not impact the methodology used to develop the turbine missile generation probabilities at RNP. Rather, analysis assessed the impact of the change in reliability of the turbine valves on the existing turbine missile generation probability. Therefore, 50.59 Criterion 8 was deemed not applicable.

Summary of 10 CFR 50.59 Evaluations

Title:
Update to UFSAR 15.6.5 (RNP Loss of Coolant Accident)

Documentation Number(s):
Action Request (AR) 02297214

Brief Description:
An update to Sections 15.6.5.5.5 and 15.6.5.5.7 of the RNP Updated Final Safety Analysis Report (UFSAR) have been prepared. These sections discuss the dose consequence inputs for the Loss of Coolant Accident (LOCA) and the dose consequences. Specifically, the change pertains to the assumed control room unfiltered inleakage for LOCA analysis, as well as the impact of this change on the dose consequences. The evaluation determined the proposed activity did not result in more than a minimal increase in consequences, and the UFSAR update does not require prior NRC approval.

Summary of 10 CFR 50.59 Evaluations

Title:
Update to UFSAR 15.7.4 (RNP Fuel Handling Accident)

Documentation Number(s):
Action Request (AR) 02291096

Brief Description:
An update to Tables 15.7.4-1 and 15.7.4-2 of the RNP Updated Final Safety Analysis Report (UFSAR) have been prepared. These tables detail the inputs for the Fuel Handling Accident (FHA) dose analyses. Specifically, the change pertains to removal of the restriction on the number of pins per assembly that can exceed 6.3 kW/ft at burnups exceeding 54 GWD/MTU.

The update changes Tables 15.7.4-1 and 15.7.4-2 in the same manner, explicitly that the following:

3. All rods in one assembly rupture, releasing their gap activity
4. Number of pins that can exceed 6.3 kW/ft over 54 GWD/MTU: 35
8. Fraction of assembly activity in gap:

I-131	0.08
Kr-85	0.10
Other Noble Gases	0.05
Other Halogens	0.05
Alkali Metals	0.12

9. Fraction of assembly activity in gap for rods over 54 GWD/MTU and 6.3 kW/ft:

Cs-134	0.36
Cs-137	0.36
Kr-85	0.30

The UFSAR will be revised to state:

3. All 204 rods in one assembly rupture, releasing their gap activity
4. Number of pins that can exceed 6.3 kW/ft over 54 GWD/MTU: 204
8. Fraction of assembly activity in gap:

I-131	0.08
Kr-85	0.30
Other Noble Gases	0.05
Other Halogens	0.05
Alkali Metals	0.12

9. Deleted

This change has been evaluated against the eight (8) questions required by 10CFR50.59. From this evaluation it is concluded that the change can be implemented under 10CFR50.59 without prior approval from the NRC.

Summary of 10 CFR 50.59 Evaluations

Title:
Replace Engineered Safety Features (ESF) Timing Relays Train A

Documentation Number(s):
Action Request (AR) 02289112
Engineering Change (EC) 415049

Brief Description:
This evaluation addresses the replacement of the A-Train obsolete Engineered Safety Features (ESF) sequencing and blackout reset time delay relays with like-in-kind relays for Robinson Unit 2 implemented under Engineering Change (EC) 415049. The sequencing relays are described in various places in the UFSAR. The UFSAR described design function of the relays is to provide a start signal (via interposing relays) at a predetermined time, following a safety injection signal or loss of offsite power, to individual loads on the 480V Emergency Bus Sections E1 and E2. The purpose of sequencing loads is to avoid large voltage and/or frequency transients on the Emergency Bus Sections that could be caused by block starting the large loads simultaneously. The replacement relays contain firmware and are considered digital components.

This change will not require a revision or addition to the Technical Specifications. This change has been evaluated against the eight (8) questions required by 10CFR50.59. From this evaluation it is concluded that the change can be implemented under 10CFR50.59 without prior approval from the NRC.

Enclosure 2
Summary of Changes, Tests, and Experiments Requiring 10 CFR 72.48 Evaluations

Summary of 10 CFR 72.48 Evaluations

There were no 10 CFR 72.48 Evaluations over the period referenced in the cover letter.

Enclosure 3
Regulatory Commitment Change

Commitment Tracking Number: 02092075-01

Existing Commitment:
In response to GL 90-03, Item (b), CP&L described how an adequate vendor interface program for RNP would be maintained which includes periodic contact with vendors of key safety-related components (beyond those provided by the NSSS supplier).

Revised Commitment:
The requirement in AD-EG-ALL-1670, Section 5.6 Vendor Re-Contact Program (Revision 0) to periodically contact vendors of critical equipment installed at RNP at least every three years to obtain new product information relevant to installed plant equipment will be eliminated.

Bases for Revision:
Based on the continued improvement and maturity of the Operating Experience, Equipment Reliability and Predictive and Preventative Maintenance Programs being implemented across the Duke Fleet, the requirement to periodically re-contact OEM vendors has no significant benefit to nuclear safety. Current Fleet level Programs and Procedures, and other methods of communication with vendors, ensure the reliability of critical SSCs important to nuclear safety.

Enclosure 4
Technical Specifications Bases, Revision 88

BASES

TO

THE FACILITY OPERATING LICENSE DPR-23

TECHNICAL SPECIFICATIONS

FOR

H. B. ROBINSON STEAM ELECTRIC PLANT

UNIT NO. 2

CAROLINA POWER & LIGHT COMPANY

DARLINGTON COUNTY, S.C.

DOCKET NO. 50-261

TECHNICAL SPECIFICATIONS BASES EFFECTIVE PAGES

TECHNICAL SPECIFICATIONS BASES EFFECTIVE PAGES

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B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

The General Design Criteria (GDC) in existence at the time HBRSEP Unit No. 2 was licensed for operation (July 1970) were contained in the proposed Appendix A to 10 CFR 50, "General Design Criteria for Nuclear Power Plants," published in the Federal Register on July 11, 1967 (Ref. 1). Proposed GDC-6 required that the reactor core with its related controls and protection systems be designed to function throughout its design lifetime without exceeding acceptable fuel damage limits which had been stipulated and justified. The core and related auxiliary system designs provide this integrity under all expected conditions of normal operation with appropriate margins for uncertainties and for specified transient situations which can be anticipated. This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur and by requiring that fuel centerline temperature stays below the melting temperature.

The restrictions of this SL prevent overheating of the fuel and cladding, as well as possible cladding perforation, that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak linear heat generation rate (LHGR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Fuel centerline melting occurs when the local LHGR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant.

(continued)

BASES

BACKGROUND (continued)

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium-water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The proper functioning of the Reactor Protection System (RPS) and main steam safety valves prevents violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB; and

b. The hot fuel pellet in the core must not experience centerline fuel melting

To maintain the integrity of the fuel cladding and prevent fission product release, it is necessary to prevent overheating of the cladding under all operating conditions. This is accomplished by maintaining the hot regions of the core within the nucleate boiling regime of heat transfer, wherein the heat transfer coefficient is very large and the clad surface temperature is only a few degrees Fahrenheit above the coolant saturation temperature. The upper boundary of the nucleate boiling regime is termed "departure from nucleate boiling" (DNB), and at this point there is a sharp reduction in the heat transfer coefficient, which would result in high clad temperatures and the possibility of clad failure. DNB is not, however, an observable parameter during reactor operation. Therefore, the observable parameters (i.e., thermal power, reactor coolant temperature and pressure) have been related to DNB through correlations. DNB correlations have been developed to

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

predict the critical heat flux and the location of DNB for axially uniform and non-uniform heat flux distributions. The local critical heat flux ratio, defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, is indicative of the margin to DNB. The minimum DNB ratio, or DNBR, during normal operational and anticipated transients, is restricted to the safety limit. A DNBR at the safety limit corresponds to a 95% probability, at a 95% confidence level, that DNB will not occur, and is chosen as an appropriate margin to DNB for all operating conditions. The DNBR safety limit is a conservative design value which is used as a basis for setting core safety limits. Based on rod bundle tests, no fuel damage is expected at this DNBR or greater. For the high thermal performance fuel the Siemens HTP correlation has a DNBR safety limit of 1.141 (Ref. 3).

The Reactor Trip System setpoints specified in Limiting Condition for Operations (LCO) 3.3.1, in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressurizer pressure, flow, core power distribution, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

The statistical core design (SCD) methodology presented in DPC-NE-2005 (Reference 6) statistically combines the effects of initial condition uncertainty and other uncertainties on DNB to determine a DNBR statistical design limit (SDL). The SDL is set such that there is a 95 percent probability with 95 percent confidence that DNB will not occur when the calculated minimum DNBR is at the DNBR limit, accounting for uncertainty. The initial condition uncertainty contained in the SDL comprises some or all of the channel uncertainty for some reactor trip functions. FSAR Chapter 15 analyses performed using the SCD methodology account for some or all of the channel uncertainty in the SDL, and any remaining uncertainties are specifically accounted for in the system analyses.

Reference 5 describes the methodology for determining the fuel melt limits.

Automatic enforcement of these reactor core SLs is provided by the appropriate operation of the RPS and the main steam safety valves.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

The SLs represent a design requirement for establishing the RPS trip setpoints identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses (as indicated in the Updated Final Safety Analysis Report (UFSAR), Ref. 4) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

The safety limits figure provided in the COLR shows the loci of points of THERMAL POWER, RCS pressure, and reactor vessel inlet temperature for which the minimum DNBR is not less than the safety analyses limit, that fuel centerline temperature remains below melting, that the average enthalpy in the hot leg is less than or equal to the enthalpy of saturated liquid, or that the core exit quality is within the limits defined by the DNBR correlation.

The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB; and

b. There must be at least a 95% probability at a 95% confidence level that the hot fuel pellet in the core does not experience centerline fuel melting.

The reactor core SLs are used to define the various RPS functions such that the above criteria are satisfied during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). To ensure that the RPS precludes the violation of the above criteria, additional criteria are applied to the Overtemperature and Overpower ΔT reactor trip functions. That is, it must be demonstrated that the average enthalpy in the hot leg is less than or equal to the saturation enthalpy and the core exit quality is within the limits defined by the DNBR correlation. Appropriate functioning of the RPS ensures that for variations in the THERMAL POWER, RCS Pressure, RCS average temperature, RCS flow rate, and ΔI that the reactor core SLs will be satisfied during steady state operations, normal operational transients, and AOOs.

(continued)

BASES

APPLICABILITY

SL 2.1.1 only applies in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The main steam safety valves and automatic protection actions serve to prevent RCS heatup to the reactor core SL conditions or to initiate a reactor trip function, which forces the unit into MODE 3. Setpoints for the reactor trip functions are specified in LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation." In MODES 3, 4, 5, and 6, Applicability is not required since the reactor is not generating significant THERMAL POWER.

SAFETY LIMIT VIOLATIONS

If SL 2.1.1 is violated, the requirement to restore compliance and go to MODE 3 places the unit in a safe condition and in a MODE in which this SL is not applicable.

The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.

REFERENCES

1. 10 CFR 50, Proposed Appendix A, 32FR10213, July 11, 1967.

2. Deleted

3. EMF-92-153(P)(A), "HTP: Departure from Nucleate Boiling Correlation for High Thermal Performance Fuel."

4. UFSAR, Sections 3.1, 4.4, 7.2, and 15.0.

5. BAW-10231P-A, Revision 1, "COPERNIC Fuel Rod Design Computer Code," Framatome ANP, Inc, January 2004.

6. DPC-NE-2005, Revision 5, "Thermal-Hydraulic Statistical Core Design Methodology," March 2016.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on RCS pressure protects the integrity of the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. By establishing an upper limit on RCS pressure, the continued integrity of the RCS is ensured. According to 10 CFR 50 Proposed Appendix A (Ref. 1), GDC 9 "Reactor Coolant System Pressure Boundary" and GDC 34 "Reactor Coolant Pressure Boundary (RCPB) Rapid Propagation Failure Prevention," the reactor coolant pressure boundary design conditions are not to be exceeded during normal operations and transients. Also, in accordance with proposed GDC 33, "Reactor Coolant Pressure Boundary Capability," reactivity accidents, including rod ejection and inadvertent and sudden releases of energy to the coolant, do not result in damage to the RCPB.

The design pressure of the RCS is 2485 psig. During normal operation and transients, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 2). To ensure system integrity, all RCS components were hydrostatically tested at 3110 psig, according to the ASME Code requirements prior to initial operation with no fuel in the core. Following inception of unit operation, RCS components shall be pressure tested, in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB. If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere, raising concerns relative to limits on radioactive releases specified in 10 CFR 100, "Reactor Site Criteria," or 10 CFR 50.67, "Accident Source Term."

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The RCS pressurizer safety valves, the main steam safety valves (MSSVs), and the reactor high pressure trip have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressurizer safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, as specified in Section III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that establishes the required relief capacity, and hence safety valve size requirements and lift settings, is a complete loss of external load without a direct reactor trip. During the transient, no control actions are assumed, except that the reactor is assumed to trip when the RCS pressure reaches the high RCS pressurizer pressure trip setpoint, the RCS pressurizer safety valves are assumed to open when the RCS pressure reaches the RCS safety valve setpoint, and the MSSVs on the secondary plant are assumed to open when the main steam pressure reaches MSSV settings.

The Reactor Protection System setpoints specified in Limiting Condition for Operations (LCO) 3.3.1, together with the settings of the RCS Pressurizer Safety Valves and MSSVs, provide pressure protection for normal operation and transients. The reactor high pressure trip setpoint specified in LCO 3.3.1 is specifically set to provide protection against overpressurization (Ref. 5). The safety analyses for both the high pressure trip and the RCS pressurizer safety valves are performed using conservative assumptions relative to pressure control devices.

More specifically, no credit is taken for operation of the following:

a. Pressurizer power operated relief valves (PORVs);

b. Main steam power operated relief valves;

c. Steam Dump System;

d. Reactor Control System;

e. Pressurizer Level Control System; or

f. Pressurizer spray valves.

(continued)

BASES (continued)

SAFETY LIMITS	The maximum transient pressure allowed in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowed in the RCS piping, valves, and fittings under USAS, Section B31.1 (Ref. 5) is 120% of design pressure. The most limiting of these two allowances is the 110% of design pressure; therefore, the SL on maximum allowable RCS pressure is 2735 psig.
APPLICABILITY	SL 2.1.2 applies in MODES 1, 2, 3, 4, and 5 because this SL could be approached or exceeded in these MODES due to overpressurization events. The SL is not applicable in MODE 6 because the reactor vessel head closure bolts are not fully tightened, making it unlikely that the RCS can be pressurized.
SAFETY LIMIT VIOLATIONS	If the RCS pressure SL is violated when the reactor is in MODE 1 or 2, the requirement is to restore compliance and be in MODE 3 within 1 hour. Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of the limits of 10 CFR 100, "Reactor Site Criteria," or 10 CFR 50.67, "Accident Source Term.". The allowable Completion Time of 1 hour recognizes the importance of reducing power level to a MODE of operation where the potential for challenges to safety systems is minimized. If the RCS pressure SL is exceeded in MODE 3, 4, or 5, RCS pressure must be restored to within the SL value within 5 minutes. Exceeding the RCS pressure SL in MODE 3, 4, or 5 is more severe than exceeding this SL in MODE 1 or 2, since the reactor vessel temperature may be lower and the vessel material, consequently, less ductile. As such, pressure must be reduced to less than the SL within 5 minutes. The action does not require reducing MODES, since this would require reducing temperature, which would compound the problem by adding thermal gradient stresses to the existing pressure stress.

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Proposed Appendix A, 32FR10213, July 11, 1967.
2. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000.
3. ASME, Boiler and Pressure Vessel Code, Section XI, Article IWX-5000.
4. Deleted
5. USAS B31.1, Standard Code for Pressure Piping, American Society of Mechanical Engineers, 1967.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs

LCO 3.0.1 through LCO 3.0.9 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.

LCO 3.0.1

LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).

LCO 3.0.2

LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered, unless otherwise specified. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that:

a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and

b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified.

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.)

The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

(continued)

LCO 3.0.2 (continued)

Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Condition no longer exists. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The ACTIONS for not meeting a single LCO adequately manage any increase in plant risk, provided any unusual external conditions (e.g., severe weather, offsite power instability) are considered. In addition, the increased risk associated with simultaneous removal of multiple structures, systems, trains or components from service is assessed and managed in accordance with 10 CFR 50.65(a)(4). Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

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LCO 3.0.3
(continued)

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. Planned entry into LCO 3.0.3 should be avoided. If it is not practicable to avoid planned entry into LCO 3.0.3, plant risk should be assessed and managed in accordance with 10 CFR 50.65(a)(4), and the planned entry into LCO 3.0.3 should have less effect on plant safety than other practicable alternatives.

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. If at the end of 1-hour, corrective measures which would allow exiting LCO 3.0.3 are not complete, but there is reasonable assurance that corrective measures will be completed in time to still allow for an orderly unit shutdown, then addition of negative reactivity can be delayed until that time. The time limits specified to enter lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, Completion Times.

A unit shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met,

b. The LCO is no longer applicable,

c. A Condition exists for which the Required Actions have now been performed, or

d. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.3 is exited.

The time limits of LCO 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for entering the next lower MODE applies. If a lower MODE is entered in less

(continued)

LCO 3.0.3 (continued)

time than allowed, however, the total allowable time to enter MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is entered in 2 hours, then the time allowed for entering MODE 4 is the next 11 hours, because the total time for entering MODE 4 is not reduced from the allowable limit of 13 hours.

Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to enter a lower MODE of operation in less than the total time allowed.

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.12, "Fuel Storage Pool Water Level." LCO 3.7.12 has an Applicability of "During movement of irradiated fuel assemblies in the fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.12 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.12 of "Suspend movement of irradiated fuel assemblies in the fuel storage pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing t he unit in a MODE or other specified condition stated in the Applicability (e.g., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with either LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered following entry into the MODE or other specified condition in the Applicability will permit continued operation within the MODE or other specified condition for an unlimited period of time. Compliance with ACTIONS that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard

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LCO 3.0.4 (continued)

to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made and the Required Actions followed after entry into the Applicability.

For example, LCO 3.0.4.a may be used when the Required Action to be entered states that an inoperable instrument channel must be placed in the trip condition within the Completion Time. Transition into a MODE or other specified condition in the Applicability may be made in accordance with LCO 3.0.4 and the channel is subsequently placed in the tripped condition within the Completion Time, which begins when the Applicability is entered. If the instrument channel cannot be placed n the tripped condition and the subsequent default ACTION ("Required Action and associated Completion Time not met") allows the OPERABLE train to be placed in operation, use of LCO 3.0.4.a is acceptable because the subsequent ACTIONS to be entered following entry into the MODE include ACTIONS (place the OPERABLE train in operation) that permit safe plant operation for an unlimited period of time in the MODE or other specified condition to be entered.

LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires risk impacts of maintenance activities to be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.” Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.” These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions.

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LCO 3.0.4 (continued)

These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

LCO 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The LCO 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the LCO, the use of the LCO 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the LCO 3.0.4.b allowance is prohibited. The LCOs governing these system and components contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on a Note in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification.

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LCO 3.0.4 (continued)

The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., RCS Specific Activity), and may be applied to other Specifications based on NRC plant specific approval. LCO 3.0.4.c is applicable for LCO 3.4.16, RCS Specific Activity.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specification.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 3.0.1 or SR 3.0.4 for any Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

LCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS.

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LCO 3.0.5
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The sole purpose of this Specification is to provide an exception (continued) to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of SRs to demonstrate:

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

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the allowed SRs. This Specification does not provide time to perform any other preventive or corrective maintenance. LCO 3.0.5 should not be used in lieu of other practicable alternatives that comply with Required Actions and that do not require changing the MODE or other specified conditions in the Applicability in order to demonstrate equipment is OPERABLE. LCO 3.0.5 is not intended to be used repeatedly.

An example of demonstrating that equipment is OPERABLE with the Required Actions not met is opening a manual valve that was closed to comply with Required Actions to isolate a flowpath with excessive Reactor Coolant System (RCS) Pressure Isolation Valve (PIV) leakage in order to perform testing to demonstrate that RCS PIV leakage is now within limit.

Examples of demonstrating equipment OPERABILITY include instances in which it is necessary to take an inoperable channel or trip system out of a tripped condition that was directed by a Required Action, if there is no Required Action Note for this purpose. An example of verifying OPERABILITY of equipment removed from service is taking a tripped channel out of the tripped condition to permit the logic to function and indicate the appropriate response during performance of required testing on the inoperable channel. Examples of demonstrating the OPERABILITY of other equipment are taking an inoperable channel or trip system out of the tripped condition 1) to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system, or 2) to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

The administrative controls in LCO 3.0.5 apply in all cases to systems or components in Chapter 3 of the Technical Specifications, as long as the testing could not be conducted while complying with the Required Actions This includes the realignment or repositioning of redundant or alternate equipment or trains previously manipulated to comply with ACTIONS, as well as equipment removed from service or declared inoperable to comply with ACTIONS.

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the unit is maintained in a safe condition are specified in the support system LCO's Required Actions. These required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability.

However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCOs' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the unit is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.15, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

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LCO 3.0.6 (continued)

Cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required. The cross train check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit.

These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Test Exception LCO 3.1.8 allows specified Technical Specification (TS) requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified continued) condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Test Exception LCOs is optional. A special operation may be performed either under the provisions of the appropriate Test Exception LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.

LCO 3.0.8

LCO 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This LCO states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control. LCO 3.0.8 applies to snubbers that have seismic function only.

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LCO 3.0.8 (continued)

It does not apply to snubbers that also have design functions to mitigate steam/water hammer or other transient loads. The snubber requirements do not meet the criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee.

When a snubber is to be rendered incapable of performing its related support function (i.e., nonfunctional) for testing or maintenance or is discovered to not be functional, it must be determined whether any system(s) require the affected snubber(s) for system OPERABILITY, and whether the plant is in a MODE or specified condition in the Applicability that requires the supported system(s) to be OPERABLE.

If an analysis determines that the supported system(s) do not require the snubber(s) to be functional in order to support the OPERABILITY of the system(s), LCO 3.0.8 is not needed. If the LCO(s) associated with any supported system(s) are not currently applicable (i.e., the plant is not in a MODE or other specified condition in the Applicability of the LCO), LCO 3.0.8 is not needed. If the supported system(s) are inoperable for reasons other than snubbers, LCO 3.0.8 cannot be used. LCO 3.0.8 is an allowance, not a requirement. When a snubber is nonfunctional, any supported system(s) may be declared inoperable instead of using LCO 3.0.8.

Every time the provisions of LCO 3.0.8 are used, HBRSEP Unit No. 2 will confirm that at least one train (or subsystem) of systems supported by the inoperable snubbers will remain capable of performing their required safety or support functions for postulated design loads other than seismic loads.

A record of the design function of the inoperable snubber (i.e., seismic vs. non-seismic) and the associated plant configuration will be available on a recoverable basis for NRC staff inspection. The applicable action for each snubber (LCO 3.0.8.a, LCO 3.0.8.b or engineering evaluation required) will be listed in the Equipment Database (EDB). A list of all plant snubbers and applicable action is included in the Shock Suppressor (Snubber) Examination and Testing Program.

LCO 3.0.8 does not apply to non-seismic snubbers. The provisions of LCO 3.0.8 are not to be applied to supported TS systems unless the supported systems would remain capable of performing their required safety or support functions for postulated design loads other than seismic loads. The risk impact of dynamic loadings other than seismic loads was not assessed as part of the development of LCO 3.0.8. These shock-type loads include thrust loads, blowdown loads, water-hammer loads, steam-hammer loads, LOCA loads and pipe rupture loads. However, there are some important distinctions between non-seismic (shock-type) loads and seismic loads which indicate that, in general, the risk impact of the out-of-service snubbers is smaller for non-seismic loads than for seismic loads.

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LCO 3.0.8 (continued)

First, while a seismic load affects the entire plant, the impact of a non-seismic load is localized to a certain system or area of the plant. Second, although non-seismic shock loads may be higher in total force and the impact could be as much or more than seismic loads, generally they are of much shorter duration than seismic loads. Third, the impact of non-seismic loads is more plant specific, and thus harder to analyze generically, than for seismic loads. For these reasons, every time LCO 3.0.8 is applied, at least one train of each system that is supported by the inoperable snubber(s) should remain capable of performing their required safety or support functions for postulated design loads other than seismic loads.

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

LCO 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single train or subsystem of a multiple train or subsystem supported system or to a single train or subsystem supported system. LCO 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function and due to the availability of the redundant train of the supported system.

LCO 3.0.8.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one train or subsystem of a multiple train or subsystem supported system. LCO 3.0.8.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

LCO 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (the Maintenance Rule) does not address seismic risk. However, use of LCO 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected train or subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

LCO 3.0.9

LCO 3.0.9 establishes conditions under which systems described in the Technical Specifications are considered to remain OPERABLE when required barriers are not capable of providing their related support function(s).

As stated in NEI 04-08, "Allowance for Non-Technical Specification Barrier Degradation on Supported System OPERABILITY (TSTF-427) Industry Implementation Guidance," March 2006, if the inability of a barrier to perform its support function does not render a supported system governed by the Technical Specifications inoperable (see NRC Regulatory Issues Summary 2001-09, Control of Hazard Barriers, dated April 2, 2001), the provisions of LCO 3.0.9 are not necessary, as the supported system is Operable.

Barriers are doors, walls, floor plugs, curbs, hatches, installed structures or components, or other devices, not explicitly described in Technical Specifications, that support the performance of the safety function of systems described in the Technical Specifications. This LCO states that the supported system is not considered to be inoperable solely due to required barriers not capable of performing their related support function(s) under the described conditions. LCO 3.0.9 allows 30 days before declaring the supported system(s) inoperable and the LCO(s) associated with the supported system(s) not met. A maximum time is placed on each use of this allowance to ensure that as required barriers are found or are otherwise made unavailable, they are restored. However, the allowable duration may be less than the specified maximum time based on the risk assessment.

If the allowed time expires and the barriers are unable to perform their related support function(s), the supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

This provision does not apply to barriers which support ventilation systems or to fire barriers. The Technical Specifications for ventilation systems provide specific Conditions for inoperable barriers. Fire barriers are addressed by other regulatory requirements and associated plant programs. This provision does not apply to barriers which are not required to support system OPERABILITY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers," dated April 2,2001).

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LCO 3.0.9 (continued)

The provisions of LCO 3.0.9 are justified because of the low risk associated with required barriers not being capable of performing their related support function. This provision is based on consideration of the following initiating event categories:

- Loss of coolant accidents;
- High energy line breaks;
- Feedwater line breaks;
- Internal flooding;
- External flooding;
- Turbine missile ejection; and
- Tornado or high wind.

The risk impact of the barriers which cannot perform their related support function(s) must be addressed pursuant to the risk assessment and management provision of the Maintenance Rule, 10 CFR 50.65(a)(4), and the associated implementation guidance, Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01,Revision 4A, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the barriers unable to perform their related support function(s). These considerations may result in risk management and other compensatory actions being required during the period that barriers are unable to perform their related support function(s).

LCO 3.0.9 may be applied to one or more trains or subsystems of a system supported by barriers that cannot provide their related support function(s), provided that risk is assessed and managed (including consideration of the effects on Large Early Release and from external events). If applied concurrently to more than one train or subsystem of a multiple train or subsystem supported system, the barriers supporting each of these trains or subsystems must provide their related support function(s) for different categories of initiating events. For example, LCO 3.0.9 may be applied for up to 30 days for more than one train of a multiple train supported system if the affected barrier for one train protects against internal flooding and the affected barrier for the other train protects against tornado missiles. In this example, the affected barrier may be the same physical barrier but serve different protection functions for each train.

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LCO 3.0.9 (continued)

If during the time that LCO 3.0.9 is being used, the required OPERABLE train or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the train(s) or subsystem(s) supported by barriers that cannot perform their related support function(s) must be declared inoperable and the associated LCOs declared not met. This 24 hour period provides time to respond to emergent conditions that would otherwise likely lead to entry into LCO 3.0.3 and a rapid plant shutdown, which is not justified given the low probability of an initiating event which could require the barrier(s) not capable of performing their related support function(s). During this 24 hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated. SR 3.0.2 and SR 3.0.3 apply in Chapter 5 only when invoked by a Chapter 5 specification.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known not to be met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a test exception are only applicable when the test exception is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance is normally precluded in a given MODE or other specified condition.

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SR 3.0.1 Surveillances, including Surveillances invoked by Required (continued) Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

SR 3.0.2 SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a “once per . . .” interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

When a Section 5.5, “Programs and Manuals,” specification states that the provisions of SR 3.0.2 are applicable, a 25% extension of the testing interval, whether stated in the specification or incorporated by reference, is permitted.

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. Examples of where SR 3.0.2 does not apply are the Containment Leakage Rate Testing Program required by 10 CFR 50, Appendix J, and the inservice testing of pumps and valves in accordance with applicable

(continued)

SR 3.0.2 (continued)

American Society of Mechanical Engineers Operation and Maintenance Code, as required by 10 CFR 50.55a. These programs establish testing requirements and Frequencies in accordance with the requirements of regulations. The TS cannot, in and of themselves, extend a test interval specified in the regulations directly or by reference.

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per ..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been performed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met.

When a Section 5.5, “Programs and Manuals,” specification states that the provisions of SR 3.0.3 are applicable, it permits the flexibility to defer declaring the testing requirement not met in accordance with SR 3.0.3 when the testing has not been completed within the testing interval (including the allowance of SR 3.0.2 if invoked by the Section 5.5 specification).

This delay period provides adequate time to perform Surveillances that have been missed. This delay period permits the performance of a Surveillance before complying with Required Actions or other remedial measures that might preclude performance of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel,

(continued)

SR 3.0.3 (continued)

the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

SR 3.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

SR 3.0.3 is only applicable if there is a reasonable expectation the associated equipment is OPERABLE or that variables are within limits, and it is expected that the Surveillance will be met when performed. Many factors should be considered, such as the period of time since the Surveillance was last performed, or whether the Surveillance, or a portion thereof, has ever been performed, and any other indications, test, or activities that might support the expectation that the Surveillance will be met when performed. An example of the use of SR 3.0.3 would be a relay contact that was not tested as required in accordance with a particular SR, but previous successful performance of the SR included the relay contact; the adjacent, physically connected relay contacts were tested during the SR performance; the subject relay contact has been tested by another SR; or historical operation of the subject relay contact has been successful. It is not sufficient to infer the behavior of the associated equipment from the performance of similar equipment. The rigor of determining whether there is a reasonable expectation a Surveillance will be met when performed should increase based on the length of time since the last performance of the Surveillance. If the Surveillance has been performed recently, a review of the Surveillance history and equipment performance may be sufficient to support a reasonable expectation that the Surveillance will be met when performed. For Surveillances that have not been performed for a long period or that have never been performed, a rigorous evaluation based on objective evidence should provide a high degree of confidence that the equipment is OPERABLE. The evaluation should be documented in sufficient detail to allow a knowledgeable individual to understand the basis for the determination.

(continued)

SR 3.0.3 (continued)

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used repeatedly to extend Surveillance intervals.

While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants.” This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown.

The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant, this evaluation should be used to determine the safest course of action. Missed Surveillances will be placed into the Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the

Applicability for which these systems and components ensure (continued) safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due to Surveillance not being met in accordance with LCO 3.0.4. However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

The provisions of SR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, MODE 3 to MODE 4, and MODE 4 to MODE 5.

(continued)

SR 3.0.4 (continued)

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both.

This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure requires entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO's Applicability, would have its Frequency specified such that it is not "due" until the specific conditions needed are met.

Alternately, the Surveillance may be stated in the form of a Note, as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, Frequency.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

According to HBRSEP Design Criteria (Ref. 1), the reactivity control systems must be redundant and capable of holding the reactor core subcritical when shut down under cold conditions. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel.

SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion or scram of all shutdown and control rods, assuming that the single control rod assembly of highest reactivity worth is fully withdrawn and the fuel and moderator temperatures are changed to the normal hot zero power value.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are provided by the use of movable control rod assemblies and soluble boric acid in the Reactor Coolant System (RCS). The two independent reactivity control systems can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the Control Rod System, together with the Chemical and Volume Control System (CVCS), provides the SDM during power operation and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the rod of highest reactivity worth remains fully withdrawn. The CVCS can compensate for fuel depletion during operation and all xenon burnout reactivity changes and maintain the reactor subcritical under cold conditions.

During power operation, SDM control is ensured by operating with the shutdown banks fully withdrawn and the control banks within the limits of LCO 3.1.6, "Control Bank Insertion Limits." When the unit is in the shutdown and

(continued)

BACKGROUND (continued)

refueling modes, the SDM requirements are met by means of rod cluster control assemblies and adjustments to the RCS boron concentration.

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in the safety analyses. The safety analysis (Ref. 2) establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with the assumption of the highest worth rod stuck out following a reactor scram. For MODE 5, the primary safety analysis that relies on the SDM limits is the boron dilution analysis.

The acceptance criteria for the SDM requirements are that the specified acceptable fuel design limits are maintained. This is done by ensuring that:

a. The reactor can be made subcritical from all operating conditions, transients, and Design Basis Events;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (departure from nucleate boiling ratio (DNBR), fuel centerline temperature limits for AOOs, and fuel temperature and energy deposition limits for the rod ejection accident); and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

One limiting accident for the SDM requirements is a main steam line break (MSLB), as described in the accident analysis (Ref. 2). The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected steam generator (SG), and consequently the RCS. This results in a reduction of the reactor coolant temperature. The resultant coolant shrinkage causes a reduction in pressure. In the presence of a negative moderator temperature coefficient, this cooldown causes an increase in core reactivity. As RCS temperature decreases, the severity of an MSLB decreases. The most limiting MSLB, with respect to potential fuel damage before a reactor trip occurs, is determined by analyzing a spectrum of breaks and breaks sizes

(continued)

APPLICABLE SAFETY ANALYSES (continued)

of a main steam line inside containment initiated at the end of core life. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the MSLB, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power, and THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1.

In addition to the limiting MSLB transient, the SDM requirement must also protect against:

a. Inadvertent boron dilution;

b. An uncontrolled rod withdrawal from subcritical or low power condition; and

c. Rod ejection.

Each of these events is discussed below.

In the boron dilution analysis, the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS, the assumed dilution flow rate and operator response time, directly affect the results of the analysis. This event is most limiting at the beginning of core life, when critical boron concentrations are highest.

Depending on the system initial conditions and reactivity insertion rate, the uncontrolled rod withdrawal transient is terminated by a high flux level trip, overtemperature ΔT trip, overpower ΔT trip, or high pressurizer pressure trip. In all cases, power level, RCS pressure, linear heat rate, and the DNBR do not exceed allowable limits.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

The ejection of a control rod rapidly adds reactivity to the reactor core, causing both the core power level and heat flux to increase with corresponding increases in reactor coolant temperatures and pressure. The ejection of a rod also produces a time dependent redistribution of core power.

SDM satisfies Criterion 2 of the NRC Policy Statement. Even though it is not directly observed from the control room, SDM is considered an initial condition process variable because it is periodically monitored to ensure that the unit is operating within the bounds of accident analysis assumptions.

LCO

SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration.

The MSLB (Ref. 2) and the boron dilution (Ref. 3) accidents are the most limiting analyses that establish the SDM value of the LCO. For MSLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed the dose limits of 10 CFR 50.67, "Accident Source Term." For the boron dilution accident, if the LCO is violated, the minimum required time (Ref. 3) assumed for operator action to terminate dilution may no longer be applicable.

APPLICABILITY

In MODE 2 with k_{eff} < 1.0 and in MODES 3 4, and 5, the SDM requirements are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analyses discussed above. In MODE 6, the shutdown reactivity requirements are given in LCO 3.9.1, "Boron Concentration." In MODES 1 and 2, SDM is ensured by complying with LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6.

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that

(continued)

ACTIONS

A.1 (continued)

boration will be continued until the SDM requirements are met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a highly concentrated solution, such as that normally found in the boric acid storage tanks, or the refueling water storage tank. The operator should borate with the best source available for the plant conditions.

In determining the boration flow rate, the time in core life must be considered. For instance, the most difficult time in core life to increase the RCS boron concentration is at the beginning of cycle when the boron concentration is greatest. Assuming that a value of 1% $\Delta k/k$ must be recovered and a boration flow rate of 60 gpm, it is possible to increase the boron concentration of the RCS by 100 ppm in approximately 5 minutes. If a boron worth of 10 pcm/ppm is assumed, this combination of parameters will increase the SDM by 1% $\Delta k/k$. These boration parameters of 60 gpm and 21000 ppm represent typical values and are provided for the purpose of offering a specific example (Ref. 6).

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODES 1 and 2 with $K_{eff} \geq 1.0$, SDM is verified by observing that the requirements of LCO 3.1.5 and LCO 3.1.6 are met. In the event that a rod is known to be untrippable, however, SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth.

In MODE 2 with $K_{eff} < 1.0$ and MODES 3, 4, and 5, the SDM is verified by performing a reactivity balance verification, considering the listed reactivity effects:

a. RCS boron concentration;

b. Control bank position;

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1 (continued)

c. RCS average temperature;

d. Fuel burnup based on previous critical boron concentration;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 3.1.
2. UFSAR, Section 15.1.5.
3. UFSAR, Section 15.4.6.
4. Deleted.
5. Deleted.
6. UFSAR, Table 9.3.4-1.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Core Reactivity

BASES

BACKGROUND

According to HBRSEP Design Criteria (Ref. 1), reactivity shall be controllable, such that subcriticality is maintained under cold conditions, and acceptable fuel design limits are not exceeded during normal operation and anticipated operational occurrences. Therefore, reactivity balance is used as a measure of the predicted versus measured core reactivity during critical operationS. The periodic confirmation of core reactivity is necessary to ensure that Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, control rod worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SDM or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") in ensuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers producing zero net reactivity. Excess reactivity can be inferred from the boron letdown curve, which provides an indication of the soluble boron concentration in the Reactor Coolant System (RCS) versus cycle burnup. Periodic measurement of the RCS boron concentration for comparison with the predicted value with other variables fixed (such as rod height, temperature, pressure, and power), provides a convenient method of ensuring that core reactivity is within design expectations and that the

(continued)

BASES (continued)

BACKGROUND (continued)

calculational models used to generate the safety analysis are adequate.

In order to achieve the required fuel cycle energy output, the uranium enrichment, in the new fuel loading and in the fuel remaining from the previous cycle, provides excess positive reactivity beyond that required to sustain steady state operation throughout the cycle. When the reactor is critical at RTP and moderator temperature, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, whatever neutron poisons (mainly xenon and samarium) are present in the fuel, and the RCS boron concentration.

When the core is producing THERMAL POWER, the fuel is being depleted and excess reactivity is decreasing. As the fuel depletes, the RCS boron concentration is reduced to decrease negative reactivity and maintain constant THERMAL POWER. The boron letdown curve is based on steady state operation at RTP. Therefore, deviations from the predicted boron letdown curve may indicate deficiencies in the design analysis, deficiencies in the calculational models, or abnormal core conditions, and must be evaluated.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for core reactivity are that the reactivity balance limit ensures plant operation is maintained within the assumptions of the safety analyses.

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations. Every accident evaluation (Ref. 2) is, therefore, dependent upon accurate evaluation of core reactivity. In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod ejection accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity balance additionally ensures that the nuclear methods provide an accurate representation of the core reactivity.

Design calculations and safety analyses are performed for each fuel cycle for the purpose of predetermining reactivity

(continued)

APPLICABLE SAFETY ANALYSES (continued)

behavior and the RCS boron concentration requirements for reactivity control during fuel depletion.

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted RCS boron concentrations for identical core conditions at beginning of cycle (BOC) do not agree, then the assumptions used in the reload cycle design analysis or the calculational models used to predict soluble boron requirements may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown curve that develop during fuel depletion may be an indication that the calculational model is not adequate for core burnups beyond BOC, or that an unexpected change in core conditions has occurred.

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RTP following startup from a refueling outage, with the control rods in their normal positions for power operation. The normalization is performed at BOC conditions, so that core reactivity relative to predicted values can be continually monitored and evaluated as core conditions change during the cycle.

Core reactivity satisfies Criterion 2 of the NRC Policy Statement.

LCO

Long term core reactivity behavior is a result of the core physics design and cannot be easily controlled once the core design is fixed. During operation, therefore, the LCO can only be ensured through measurement and tracking, and appropriate actions taken as necessary. Large differences between actual and predicted core reactivity may indicate that the assumptions of the DBA and transient analyses are no longer valid, or that the uncertainties in the Nuclear Design Methodology are larger than expected. A limit on the reactivity balance of ± 1% $\Delta k/k$ has been established based on engineering judgment. A 1% deviation in reactivity from

(continued)

BASES (continued)

LCO (continued)

that predicted is larger than expected for normal operation and should therefore be evaluated.

When measured core reactivity is within 1% Δk/k of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits. Since deviations from the limit are normally detected by comparing predicted and measured steady state RCS critical boron concentrations, the difference between measured and predicted values would be approximately 100 ppm (depending on the boron worth) before the limit is reached. These values are well within the uncertainty limits for analysis of boron concentration samples, so that spurious violations of the limit due to uncertainty in measuring the RCS boron concentration are unlikely.

APPLICABILITY

The limits on core reactivity must be maintained during MODES 1 and 2 because a reactivity balance must exist when the reactor is critical or producing THERMAL POWER. As the fuel depletes, core conditions are changing, and confirmation of the reactivity balance ensures the core is operating as designed. This Specification does not apply in MODES 3, 4, and 5 because the reactor is shut down and the reactivity balance is not changing.

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Boron Concentration") ensure that fuel movements are performed within the bounds of the safety analysis. An SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling).

ACTIONS

A.1 and A.2

Should an anomaly develop between measured and predicted core reactivity, an evaluation of the core design and safety analysis must be performed. Core conditions are evaluated to determine their consistency with input to design calculations. Measured core and process parameters are evaluated to determine that they are within the bounds of

(continued)

BASES (continued)

ACTIONS

A.1 and A.2 (continued)

the safety analysis, and safety analysis calculational models are reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 72 hours is based on the low probability of a DBA occurring during this period, and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

Following evaluations of the core design and safety analysis, the cause of the reactivity anomaly may be resolved. If the cause of the reactivity anomaly is a mismatch in core conditions at the time of RCS boron concentration sampling, then a recalculation of the RCS boron concentration requirements may be performed to demonstrate that core reactivity is behaving as expected. If an unexpected physical change in the condition of the core has occurred, it must be evaluated and corrected, if possible. If the cause of the reactivity anomaly is in the calculation technique, then the calculational models must be revised to provide more accurate predictions. If any of these results are demonstrated, and it is concluded that the reactor core is acceptable for continued operation, then the boron letdown curve may be renormalized and power operation may continue. If operational restriction or additional SRs are necessary to ensure the reactor core is acceptable for continued operation, then they must be defined.

The required Completion Time of 72 hours is adequate for preparing whatever operating restrictions or Surveillances that may be required to allow continued reactor operation.

B.1

If the core reactivity cannot be restored to within the 1% $\Delta k/k$ limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. If the SDM for MODE 3 is not met, then the boration required by SR 3.1.1.1 would occur. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made, considering that other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Surveillance is performed prior to entering MODE 1 as an initial check on core conditions and design calculations at BOC. The SR is modified by a Note. The Note indicates that the normalization of predicted core reactivity to the measured value must take place within the first 60 effective full power days (EFPD) after each fuel loading. This allows sufficient time for core conditions to reach steady state, but prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1 UFSAR Section 3.1.

2. UFSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to HBRSEP Design Criteria (Ref. 1), the reactor core with its related controls and protection systems are designed to function throughout its design lifetime without exceeding acceptable fuel damage limits. The core design, together with reliable process and decay heat removal systems, provides for this capability under expected conditions of normal operation with appropriate margins for uncertainties and anticipated transient situations. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The reactor is designed to operate with a negative MTC over the largest possible range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Both initial and reload cores are designed so that the beginning of cycle (BOC) MTC is less than or equal to zero when THERMAL POWER is at RTP. The actual value of the MTC is dependent on core characteristics, such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed distributed poisons to yield an MTC at BOC within the range analyzed in the plant accident analysis. The end of cycle (EOC) MTC is also limited by the requirements of the accident analysis. Fuel cycles that are designed to achieve high burnups or that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the EOC limit.

(continued)

BASES

BACKGROUND (continued)

The limitations on MTC are provided to ensure that the value of this coefficient remains within the limiting conditions assumed in the UFSAR accident and transient analyses.

If the LCO limits are not met, the unit response during transients may not be as predicted. The core design could violate the departure from nucleate boiling ratio criteria of the approved correlation, which could lead to a loss of the fuel cladding integrity.

The SRs for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits, since this coefficient changes slowly, due principally to the reduction in RCS boron concentration associated with fuel burnup.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified MTC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2); and

b. The MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

The UFSAR, Chapter 15 (Ref. 2), contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the most positive value and most negative value of the MTC are important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions to ensure that the accident results are bounding.

The consequences of accidents that cause core overheating must be evaluated when the MTC is positive. Such accidents include the rod withdrawal transient from either zero (Ref. 3) or RTP, loss of main feedwater flow, and loss of forced reactor coolant flow. The consequences of accidents that cause core overcooling must be evaluated when the MTC is negative. Such accidents include sudden feedwater flow increase and sudden decrease in feedwater temperature.

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APPLICABLE SAFETY ANALYSES (continued)

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is the BOC or EOC life. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

MTC values are bounded in reload safety evaluations assuming steady state conditions at BOC and EOC. An EOC measurement is conducted at conditions when the RCS boron concentration reaches approximately 300 ppm. The measured value may be extrapolated to project the EOC value, in order to confirm reload design predictions.

MTC satisfies Criterion 2 of the NRC Policy Statement. Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the MTC to be within specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the accident analysis during operation.

Assumptions made in safety analyses require that the MTC be less positive than a given upper bound and more positive than a given lower bound. The MTC is most positive at BOC; this upper bound must not be exceeded. This maximum upper limit occurs at BOC, all rods out (ARO), hot zero power conditions. At EOC the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The Surveillance checks at BOC and EOC on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

(continued)

BASES

LCO (continued)

The LCO establishes a maximum positive value that cannot be exceeded. The BOC positive limit and the EOC negative limit are established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

In MODE 1, the limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled CONTROL ROD assembly or group withdrawal) will not violate the assumptions of the accident analysis. The lower MTC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents will not violate the assumptions of the accident analysis. In MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents using the MTC as an analysis assumption are initiated from these MODES.

ACTIONS

A.1

If the BOC MTC limit is violated, administrative withdrawal limits for control banks must be established to maintain the MTC within its limits. The MTC becomes more negative with control bank insertion and decreased boron concentration. A Completion Time of 24 hours provides enough time for evaluating the MTC measurement and computing the required bank withdrawal limits.

(continued)

BASES

ACTIONS

A.1 (continued)

As cycle burnup is increased, the RCS boron concentration will be reduced. The reduced boron concentration causes the MTC to become more negative. Using physics calculations, the time in cycle life at which the calculated MTC will meet the LCO requirement can be determined. At this point in core life Condition A no longer exists. The unit is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

B.1

If the required administrative withdrawal limits at BOC are not established within 24 hours, the unit must be brought to MODE 2 with $k_{eff} < 1.0$ to prevent operation with an MTC that is more positive than that assumed in safety analyses.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

C.1

Exceeding the EOC MTC limit means that the safety analysis assumptions for the EOC accidents that use a bounding negative MTC value may be invalid. If the EOC MTC limit is exceeded, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 4 within 12 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

This SR requires measurement of the MTC at BOC prior to entering MODE 1 in order to demonstrate compliance with the most positive MTC LCO. Meeting the limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels.

The BOC MTC value for ARO will be inferred from isothermal temperature coefficient measurements obtained during the physics tests after refueling. The ARO value can be directly compared to the BOC MTC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

SR 3.1.3.2

In similar fashion, the LCO demands that the MTC be less negative than the specified value assumed in the most limiting accident analysis for EOC full power conditions. This measurement may be performed at any THERMAL POWER, but its results must be extrapolated to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC value will gradually become more negative with further core depletion and boron concentration reduction, a 300 ppm SR value of MTC should necessarily be less negative than the EOC LCO limit. The 300 ppm SR value is sufficiently less negative than the EOC LCO limit value to ensure that the LCO limit will be met when the 300 ppm Surveillance criterion is met.

SR 3.1.3.2 is modified by three Notes that include the following requirements:

a. The SR is not required to be performed until 7 effective full power days (EFFDs) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.2 (continued)

b. If the 300 ppm Surveillance limit is exceeded, it is possible that the EOC limit on MTC could be reached before the planned EOC. Because the MTC changes slowly with core depletion, the Frequency of 14 effective full power days is sufficient to avoid exceeding the EOC limit.

c. The Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is less negative than the 60 ppm Surveillance limit, the EOC limit will not be exceeded because of the gradual manner in which MTC changes with core burnup.

REFERENCES

1. UFSAR Section 3.1.

2. UFSAR, Section 15.0.5.

3. UFSAR, Section 15.4.1.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Rod Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY (e.g., trippability) of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM.

The applicable criteria for these reactivity and power distribution design requirements are described in the UFSAR (Ref. 1) and 10 CFR 50.46, Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants" (Ref. 2).

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved by their control rod drive mechanisms (CRDMs). Each CRDM moves its RCCA one step (approximately 5/8 inch) at a time, but at varying rates (steps per minute) depending on the signal output from the Rod Control System.

The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups

(continued)

BASES

BACKGROUND (continued)

that are moved in a staggered fashion, but always within one step of each other. HBRSEP has four control banks and two shutdown banks.

The shutdown banks are maintained either in the fully inserted or fully withdrawn position. The control banks are moved in an overlap pattern, using the following withdrawal sequence: When control bank A reaches a predetermined height in the core, control bank B begins to move out with control bank A. Control bank A stops at the position of maximum withdrawal, and control bank B continues to move out. When control bank B reaches a predetermined height, control bank C begins to move out with control bank B. This sequence continues for the remaining control banks. The insertion sequence is the opposite of the withdrawal sequence. The control rods are arranged in a radially symmetric pattern, so that control bank motion does not introduce radial asymmetries in the core power distributions.

The axial position of shutdown rods and control rods is indicated by two separate and independent systems, which are the Bank Demand Position Indication System (commonly called group step counters) and the Analog Rod Position Indication (ARPI) System.

The Bank Demand Position Indication System counts the pulses from the rod control system that moves the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The ARPI System provides a highly accurate indication of actual control rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube with a center to center distance of 3.75 inches, which is six steps.

(continued)

BASES

BACKGROUND (continued)

The maximum uncertainty of the ARPI System is ± 12 steps (± 7.5 inches). With an indicated deviation of 12 steps between the group step counter and ARPI, the maximum deviation between actual rod position and the demand position could be 24 steps, or 15 inches (Ref. 4 and 6).

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (Ref. 3). The acceptance criteria for addressing control rod inoperability or misalignment are that:

There be no violations of:

a. specified acceptable fuel design limits, or
b. Reactor Coolant System (RCS) pressure boundary integrity.

Two types of misalignment are distinguished. During movement of a control rod group, one rod may stop moving, while the other rods in the group continue. This condition may cause excessive power peaking. The second type of misalignment occurs if one rod fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the control rods to meet the SDM requirement, with the maximum worth rod stuck fully withdrawn.

Two types of analysis are performed in regard to static rod misalignment (Ref. 3). With control banks at their insertion limits, one type of analysis considers the case when any one rod is completely inserted into the core. The second type of analysis considers the case of a completely withdrawn single rod from a bank inserted in excess of its insertion limit. Satisfying limits on departure from nucleate boiling ratio in both of these cases bounds the situation when a rod is misaligned from its group by 12 steps.

Another type of misalignment occurs if one RCCA fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition is assumed in the evaluation to determine that the required SDM is met with the maximum worth RCCA also fully withdrawn (Ref. 5).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The Required Actions in this LCO ensure that either deviations from the alignment limits will be corrected or that THERMAL POWER will be adjusted so that excessive local linear heat generation rates (LHGRs) will not occur, and that the requirements on SDM and ejected rod worth are preserved.

Continued operation of the reactor with a misaligned control rod is allowed if the heat flux hot channel factor ($F_Q(X,Y,Z)$) and the nuclear enthalpy hot channel factor ($F_{\Delta H}(X,Y)$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned, the assumptions that are used to determine the rod insertion limits, AFD limits, and quadrant power tilt limits are not preserved. Therefore, the limits may not preserve the design peaking factors, and $F_Q(X,Y,Z)$ and $F_{\Delta H}(X,Y)$ must be verified directly by incore mapping. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(X,Y,Z)$ and $F_{\Delta H}(X,Y)$ to the operating limits.

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of the NRC Policy Statement.

LCO

The limits on shutdown or control rod alignments ensure that the assumptions in the safety analysis will remain valid. The requirements on OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The OPERABILITY requirements (i.e., trippability to meet SDM) are separate from the alignment requirements, which ensure that the RCCAs and banks maintain the correct power distribution and rod alignment. The rod OPERABILITY requirement is satisfied provided the rod will fully insert in the required time on a valid signal. CRDM malfunctions that result in inability to move a rod (e.g., rod urgent failures), which do not impact trippability, do not necessarily result in rod inoperability.

The requirement to maintain the rod alignment to within the specified limits is conservative. The minimum misalignment assumed in safety analysis is 24 steps (15 inches), and in

(continued)

BASES

LCO (continued)

some cases a total misalignment from fully withdrawn to fully inserted is assumed.

Failure to meet the requirements of this LCO may produce unacceptable power peaking factors and LHGRs, or unacceptable SDMs, all of which may constitute initial conditions inconsistent with the safety analysis.

This LCO is modified by a note indicating individual control rod position indications may not be within limits for up to and including one hour following substantial control rod movement. This allows up to one hour of thermal soak time to allow the control rod drive shaft to reach thermal equilibrium and thus present a consistent position indication. Substantial rod movement is considered to be 10 or more steps in one direction in less than one hour.

In accordance with this note, the comparison of the bank demand position and the RPI may take place at any time up to one hour after rod motion, at any power level. Based on this allowance, rod position may be considered within limits during the thermal soak time to allow position indication to stabilize.

APPLICABILITY

The requirements on RCCA OPERABILITY and alignment are applicable in MODES 1 and 2 because these are the only MODES in which neutron (or fission) power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the control rods are inserted and the reactor is shut down and not producing fission power. In the shutdown MODES, the OPERABILITY of the shutdown and control rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. See LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," for SDM in MODES 3, 4, and 5 and LCO 3.9.1, "Boron Concentration," for boron concentration requirements during refueling.

(continued)

BASES

ACTIONS

A.1.1 and A.1.2

When one or more rods are inoperable (e.g., untrippable), there is a possibility that the required SDM may be adversely affected. Under these conditions, it is important to determine the SDM, and if it is less than the required value, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate for determining SDM and, if necessary, for initiating emergency boration and restoring SDM.

In this situation, SDM verification must include the worth of the untrippable rod, as well as a rod of maximum worth.

(continued)

BASES

ACTIONS (continued)

A.2

If the inoperable rod(s) cannot be restored to OPERABLE status, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3
within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

B.1

When a rod becomes misaligned, it can usually be moved and is still trippable. If the rod can be realigned within the Completion Time of 1 hour, local xenon redistribution during this short interval will not be significant, and operation may proceed without further restriction.

An alternative to realigning a single misaligned RCCA to the group average position is to align the remainder of the group to the position of the misaligned RCCA. However, this must be done without violating the bank sequence, overlap, and insertion limits specified in LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits." The Completion Time of 1 hour gives the operator sufficient time to adjust the rod positions in an orderly manner.

B.2.1.1 and B.2.1.2

With a misaligned rod, SDM must be verified to be within limit or boration must be initiated to restore SDM to within limit.

In many cases, realigning the remainder of the group to the misaligned rod may not be desirable. For example, realigning control bank B to a rod that is misaligned 15 steps from the top of the core would require a significant power reduction, since control bank D must be moved fully in and control bank C must be moved in to approximately 100 to 115 steps.

(continued)

BASES

ACTIONS

B.2.2.1 and B.2.1.2 (continued)

Power operation may continue with one RCCA trippable but misaligned, provided that SDM is verified within 1 hour. The Completion Time of 1 hour represents the time necessary for determining the actual unit SDM and, if necessary, aligning and starting the necessary systems and components to initiate boration.

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6

For continued operation with a misaligned rod, RTP must be reduced, SDM must periodically be verified within limits, hot channel factors ($F_Q(X,Y,Z)$ and $F_{\Delta H}(X,Y)$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible.

Reduction of power to 70% RTP ensures that local LHGR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded (Ref. 7). The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Completion Time of once per 12 hours is sufficient to ensure this requirement continues to be met.

Verifying that $F_Q(X,Y,Z)$ and $F_{\Delta H}(X,Y)$ are within the required limits ensures that current operation at 70% RTP with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain flux maps of the core power distribution using the incore flux mapping system and to calculate $F_Q(X,Y,Z)$ and $F_{\Delta H}(X,Y)$.

Once current conditions have been verified acceptable, time is available to perform evaluations of accident analysis to determine that core limits will not be exceeded during a Design Basis Event for the duration of operation under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

(continued)

BASES

ACTIONS (continued)

C.1

When Required Actions cannot be completed within their Completion Time, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours, which eliminates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging the plant systems.

D.1.1 and D.1.2

More than one control rod becoming misaligned from its group average position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. One hour allows the operator adequate time to determine SDM. Restoration of the required SDM, if necessary, requires increasing the RCS boron concentration to provide negative reactivity, as described in the Bases of LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and start the boric acid pumps. Boration will continue until the required SDM is restored.

D.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement, the unit conditions fall outside of the accident analysis assumptions. Since automatic bank sequencing would continue to cause misalignment, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

(continued)

BASES

ACTIONS

D.2 (continued)

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.4.2

Verifying each control rod is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2, tripping each control rod would result in radial or axial power tilts, or oscillations. Exercising each individual control rod provides increased confidence that all rods continue to be OPERABLE without exceeding the alignment limit, even if they are not regularly tripped. Moving each control rod by 10 steps will not cause radial or axial power tilts, or oscillations, to occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Between required performances of SR 3.1.4.2 (determination of control rod OPERABILITY by movement), if a control rod(s) is discovered to be immovable by the normal CRDM, but remains trippable, the control rod(s) is considered to be OPERABLE. At any time, if a control rod(s) is immovable by the normal CRDM, a determination of the trippability (OPERABILITY) of the control rod(s) must be made, and appropriate action taken.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.4.3

Verification of rod drop times allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. Measuring rod drop times prior to reactor criticality, after reactor vessel head removal, ensures that the reactor internals and rod drive mechanism will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect control rod motion or drop time. This testing is performed with all RCPs operating and the average moderator temperature ≥ 540ºF to simulate a reactor trip under actual conditions.

This Surveillance is performed during a plant outage, due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance were performed with the reactor at power.

REFERENCES

1. UFSAR Section 3.1.
2. 10 CFR 50.46.
3. UFSAR Section 15.4.
4. CP&L Letter, E.E. Utley to NRC, Rod Position Indication System, dated December 14, 1979.
5. UFSAR, Section 15.0.6.
6. NRC Letter to CP&L, Mr. J. A. Jones, "Amendment No. 48 to Facility Operating License No. DPR-23 for HBRSEP, Unit No. 2," dated August 29, 1979.
7. UFSAR, Section 15.4.3.2.

B 3. REACTIVITY CONTROL SYSTEMS

B 3.1.5 Shutdown Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available ejected rod worth, SDM and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are described in the UFSAR (Ref. 1) and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants" (Ref 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. HBRSEP has four control banks and two shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks can be automatically controlled by the Rod Control System, or they can be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating). The control banks must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power operations.

(continued)

BASES

BACKGROUND (continued)	Hence, they are not capable of adding a large amount of positive reactivity. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity changes associated with large changes in RCS temperature. The design calculations are performed with the assumption that the shutdown banks are withdrawn first. The shutdown banks can be fully withdrawn without the core going critical. This provides available negative reactivity in the event of boration errors. The shutdown banks are controlled manually by the control room operator. During normal unit operation, the shutdown banks are either fully withdrawn or fully inserted. The shutdown banks must be completely withdrawn from the core, prior to withdrawing any control banks during an approach to criticality. The shutdown banks are then left in this position until the reactor is shut down. They affect core power and burnup distribution, and add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.
APPLICABLE SAFETY ANALYSES	On a reactor trip, all RCCAs (shutdown banks and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown banks shall be at or above their insertion limits and available to insert the maximum amount of negative reactivity on a reactor trip signal. The control banks may be partially inserted in the core, as allowed by LCO 3.1.6, "Control Bank Insertion Limits." The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") following a reactor trip from full power. The combination of control banks and shutdown banks (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power, and to maintain the required SDM at rated no load temperature (Ref. 3). The shutdown bank insertion limit also limits the reactivity worth of an ejected shutdown rod. The acceptance criteria for addressing shutdown and control rod bank insertion limits and inoperability or misalignment is that:

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	There be no violations of: a. specified acceptable fuel design limits, or b. RCS pressure boundary integrity. As such, the shutdown bank insertion limits affect safety analysis involving core reactivity and SDM (Ref. 3). The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and, as such, satisfy Criterion 2 of the NRC Policy Statement.
LCO	The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. The shutdown bank insertion limits are defined in the COLR.
APPLICABILITY	The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. The applicability in MODE 2 begins prior to initial control bank withdrawal, during an approach to criticality, and continues throughout MODE 2, until all control bank rods are again fully inserted by reactor trip or by shutdown. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip. The shutdown banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. In MODE 3, 4, 5, or 6, the shutdown banks contribute to the SDM. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6. The Applicability requirements have been modified by a Note indicating the LCO requirement is suspended during SR 3.1.4.2. This SR verifies the freedom of the rods to

(continued)

BASES

APPLICABILITY (continued)

move, and requires the shutdown bank to move below the LCO limits, which would normally violate the LCO.

ACTIONS

A.1.1, A.1.2 and A.2

When one or both shutdown banks is not within insertion limits, 2 hours is allowed to restore the shutdown banks to within the insertion limits. This is necessary because the available SDM may be significantly reduced, with one or more of the shutdown banks not within their insertion limits. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

B.1

If the shutdown banks cannot be restored to within their insertion limits within 2 hours, the unit must be brought to a MODE where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Verification that the shutdown banks are within their insertion limits prior to an approach to criticality ensures that when the reactor is critical, or being taken critical, the shutdown banks will be available to shut down the reactor, and the required SDM will be maintained following a reactor trip. This SR and Frequency ensure that the

(continued)

BASES

SURVEILLANCES REQUIREMENTS

SR 3.1.5.1 (continued)

shutdown banks are withdrawn before the control banks are withdrawn during a unit startup.

Since the shutdown banks are positioned manually by the control room operator, a verification of shutdown bank position at a Frequency in accordance with the Surveillance Frequency Control Program, after the reactor is taken critical, is adequate to ensure that they are within their insertion limits. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 3.1.

2. 10 CFR 50.46.

3. UFSAR, Chapter 15.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available SDM, and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are described in the UFSAR (Ref. 1) and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants" (Ref 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs consists of two groups that are moved in a staggered fashion, but always within one step of each other. HBRSEP has four control banks and two shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control bank insertion limits are specified in the COLR. An example is provided for information only in Figure B 3.1.6-1. The control banks are required to be at or above the insertion limit lines.

Figure B 3.1.6-1 also indicates how the control banks are moved in an overlap pattern. Overlap is the distance travelled together by two control banks. The predetermined

(continued)

BASES

BACKGROUND (continued)

position of control bank C, at which control bank D will begin to move with bank C on a withdrawal, will be at 128 steps for a fully withdrawn position of 228 steps. The fully withdrawn position is defined in the COLR.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks can be controlled automatically by the Rod Control System, or they can be manually controlled. They are capable of adding reactivity very quickly (compared to borating or diluting).

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.4, LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits ensure the required SDM is maintained.

Operation within the subject LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Trip System (RTS) trip function.

APPLICABLE SAFETY ANALYSES

The shutdown and control bank insertion limits, AFD, and QPTR LCOs are required to prevent power distributions that could result in fuel cladding failures in the event of a LOCA, loss of flow, ejected rod, or other accident requiring termination by an RPS trip function.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that:

There be no violations of:

a. specified acceptable fuel design limits, or
b. Reactor Coolant System pressure boundary integrity.

The core remains subcritical after an accident or transient.

As such, the shutdown and control bank insertion limits affect safety analysis involving core reactivity and power distributions (Ref. 3).

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes the maximum worth RCCA remains fully withdrawn upon trip (Ref. 3).

Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worths.

The control and shutdown bank insertion limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 3).

The insertion limits satisfy Criterion 2 of the NRC Policy Statement, in that they are initial conditions assumed in the safety analysis.

LCO

The limits on control banks sequence, overlap, and physical insertion, as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is maintained, and ensuring adequate

(continued)

BASES

LCO (continued)

negative reactivity insertion is available on trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion.

APPLICABILITY

The control bank sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2 with $k_{eff} \geq 1.0$. These limits must be maintained, since they preserve the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions. Applicability in MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

The applicability requirements have been modified by a Note indicating the LCO requirements are suspended during the performance of SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the control bank to move below the LCO limits, which would violate the LCO.

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2

When the control banks are outside the acceptable insertion limits, they must be restored to within those limits. This restoration can occur in two ways:

a. Reducing power to be consistent with rod position; or

b. Moving rods to be consistent with power.

Also, verification of SDM or initiation of boration to regain SDM is required within 1 hour, since the SDM in MODES 1 and 2 normally ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") has been upset. If control banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

(continued)

BASES

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2 (continued)

Similarly, if the control banks are found to be out of sequence or in the wrong overlap configuration, they must be restored to meet the limits.

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the simultaneous occurrence of either a LOCA, loss of flow accident, ejected rod accident, or other accident during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability.

The allowed Completion Time of 1 hour for restoring the banks to within the insertion limits and 2 hours for restoring the banks to within the sequence and overlaps limits provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

C.1

If the Required Actions cannot be completed within the associated Completion Times, the plant must be brought to MODE 3 (utilizing normal operating procedures), where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits.

The estimated critical position (ECP) depends upon a number of factors, one of which is xenon concentration. If the ECP was calculated long before criticality, xenon concentration could change to make the ECP substantially in error. Conversely, determining the ECP immediately before

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1 (continued)

criticality could be an unnecessary burden. There are a number of unit parameters requiring operator attention at that point. Performing the ECP calculation within 4 hours prior to criticality avoids a large error from changes in xenon concentration, but allows the operator some flexibility to schedule the ECP calculation with other startup activities.

SR 3.1.6.2

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. If the insertion limit monitor becomes inoperable, verification of the control bank position at a Frequency in accordance with the Surveillance Frequency Control Program is sufficient to detect control banks that may be approaching the insertion limits.

SR 3.1.6.3

When control banks are maintained within their insertion limits as checked by SR 3.1.6.2 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. A Frequency of 12 hours is consistent with the insertion limit check above in SR 3.1.6.2.

REFERENCES

1. UFSAR, Sections 3.1.2.14, 3.1.2.27, 3.1.2.28, 3.1.2.29, 3.1.2.30, 3.1.2.31, and 3.1.2.32.

2. 10 CFR 50.46.

3. UFSAR, Chapter 15.

BASES

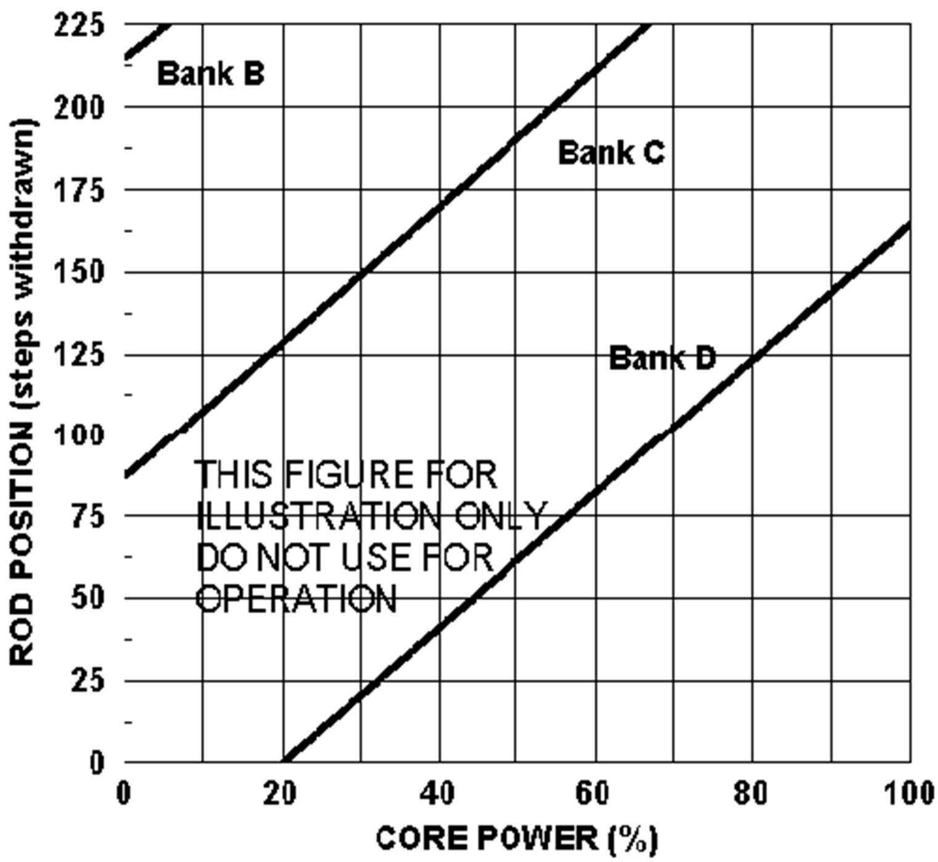

Figure B 3.1.6-1 (page 1 of 1)
Control Bank Insertion vs. Percent RTP

B 3.1 REACTIVITY CONTROL SYSTEM

B 3.1.7 Rod Position Indication

BASES

BACKGROUND

The applicable design criteria for rod position indication described in the UFSAR (Ref. 1). LCO 3.1.7 is required to ensure OPERABILITY of the control rod position indicators to determine control rod positions and thereby ensure compliance with the control rod alignment and insertion limits.

The OPERABILITY, including position indication, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM. Rod position indication is required to assess OPERABILITY and misalignment.

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms. The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control.

(continued)

BASES

BACKGROUND (continued)

The axial position of shutdown rods and control rods are determined by two separate and independent systems: the Bank Demand Position Indication System (commonly called group step counters) and the Analog Rod Position Indication (ARPI) System.

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The ARPI System provides a highly accurate indication of actual control rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a series of coils spaced along a hollow tube with a center to center distance of 3.75 inches, which is 6 steps. Therefore, the normal indication accuracy of the ARPI System is ± 6 steps (± 3.75 inches), and the maximum uncertainty is ± 12 steps (± 7.5 inches). With an indicated deviation of 12 steps between the group step counter and ARPI, the maximum deviation between actual rod position and the demand position could be 24 steps, or 15 inches (Ref. 2).

APPLICABLE SAFETY ANALYSES

Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 3), with control or shutdown rods operating outside their limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod worth, and with minimum SDM (LCO 3.1.5, "Shutdown Bank Insertion Limits," and

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

LCO 3.1.6, "Control Bank Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, "Rod Group Alignment Limits"). Control rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions.

The control rod position indicator channels satisfy Criterion 2 of the NRC Policy Statement. The control rod position indicators monitor control rod position, which is an initial condition of the accident.

LCO

LCO 3.1.7 specifies that one ARPI System and one Bank Demand Position Indication System be OPERABLE for each control rod. For the control rod position indicators to be OPERABLE requires meeting the SR of the LCO and the following:

a. The ARPI System meets the requirements of LCO 3.1.4, "Rod Group Alignment Limits";

b. For the ARPI System there are no known failed coils; and

c. The Bank Demand Indication System had been previously reset to zero with all rods in the fully inserted position.

By meeting the requirements of LCO 3.1.4, the Bank Demand Position Indication System can be used for indication of the measurement of control rod bank position.

A deviation of less than the allowable limit, given in LCO 3.1.4, in position indication for a single control rod, ensures high confidence that the position uncertainty of the corresponding control rod group is within the assumed values used in the analysis (that specified control rod group insertion limits).

These requirements ensure that control rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged.

(continued)

BASES

LCO (continued)

OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned control rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

This LCO is modified by a note indicating individual control rod position indications may not be within limits for up to and including one hour following substantial control rod movement. This allows up to one hour of thermal soak time to allow the control rod drive shaft to reach thermal equilibrium and thus present a consistent position indication. Substantial rod movement is considered to be 10 or more steps in one direction in less than one hour.

In accordance with this note, the comparison of the bank demand position and the RPI may take place at any time up to one hour after rod motion, at any power level. Based on this allowance, rod position may be considered within limits during the thermal soak time to allow position indication to stabilize.

APPLICABILITY

The requirements on the ARPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System.

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable rod position indicator per group and each demand position indicator per bank. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

(continued)

A.1

When one ARPI channel per group fails, the position of the rod can still be determined by use of the incore movable detectors. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Action of B.1 or B.2 below is required. Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

(continued)

BASES

ACTIONS (continued)

A.2

Reduction of THERMAL POWER to ≤ 50% RTP more than offsets the increase in core F_Q and $F^N_{\Delta H}$ due to rod position. The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above.

B.1 and B.2

These Required Actions clarify that when one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction, since the position was last determined, the Required Actions of A.1 and A.2 are still appropriate but must be initiated promptly under Required Action B.1 to begin verifying that these rods are still properly positioned, relative to their group positions.

If, within 4 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP within 8 hours to avoid undesirable power distributions that could result from continued operation at > 50% RTP, if one or more rods are misaligned by more than 24 steps. The allowed Completion Time of 4 hours provides an acceptable period of time to verify the rod positions.

C.1.1, C.1.2, and C.1.3

Condition C is modified by a footnote that provides a condition for two demand position indicators per bank to be inoperable for one or more banks. The footnote states that the required action is restoration of one demand position indicator per bank and a completion time of 4 hours. When one or more demand position indicators are inoperable in one or more banks, Condition C is entered. If two demand position indicators are inoperable in a bank, the footnote required action and completion time are applied. After expiration of the 4 hour completion time associated with the footnote condition, Required Action D.1 to be in MODE 3 within 6 hours is required to be entered. Additionally, during the time when two demand indicators per bank are inoperable, Required Action C.1.3 cannot be completed. Expiration of the C.1.3 completion time will require entry into Required Action D.1 to be in MODE 3 within 6 hours. Required Action D.1 would be applicable

(continued)

BASES

ACTIONS (continued)

until power has been reduced to ≤ 50%, at which time the Required Action C.2 would be met.

With one demand position indicator per bank inoperable, the rod positions can be determined by the ARPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indicators are OPERABLE, that the position of each rod in the affected bank(s) is within 7.5 inches of the average of the individual rod positions in the affected bank(s), for bank positions < 200 steps and that the position of each rod in the affected bank(s) is within 15 inches of the bank demand position for bank positions ≥ 200 steps within the allowed Completion Time of once every 8 hours is adequate.

C.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions C.1.1 and C.1.2 or reduce power to ≤ 50% RTP.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

A CHANNEL CALIBRATION of the ARPI System is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to the measured parameter with the necessary range and accuracy. The 24 month Frequency is based on the need to perform this Surveillance under conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

(continued)

BASES

REFERENCES

1. UFSAR Section 3.1.2.

2. CP&L Letter, E. E. Utley to NRC, "Rod Position Indication System," dated 12/14/79.

3. UFSAR, Chapter 15.

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B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 PHYSICS TESTS Exceptions - MODE 2

BASES

BACKGROUND

The primary purpose of the MODE 2 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow certain PHYSICS TESTS to be performed.

Section XI of 10 CFR 50, Appendix B (Ref. 1), requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the plant. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program are to:

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in the design and analysis;

c. Verify the assumptions used to predict unit response;

d. Ensure that installation of equipment in the facility has been accomplished in accordance with the design; and

e. Verify that the operating and emergency procedures are adequate.

To accomplish these objectives, testing is performed prior to initial criticality, during startup, during low power operations, during power ascension, at high power, and after each refueling. The PHYSICS TESTS requirements for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions and that the core can be operated as designed.

PHYSICS TESTS procedures are written and approved in accordance with established formats. The procedures include

(continued)

BASES

BACKGROUND (continued)

all information necessary to permit a detailed execution of the testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures and test results are approved prior to continued power escalation and long term power operation.

The PHYSICS TESTS required for reload fuel cycles in MODE 2 are listed below:

a. Critical Boron Concentration - Control Rods Withdrawn;

b. Critical Boron Concentration - Control Rods Inserted;

c. Control Rod Worth;

d. Isothermal Temperature Coefficient (ITC); and

These and other supplementary tests may be required to calibrate the nuclear instrumentation or to diagnose operational problems. These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance.

a. The Critical Boron Concentration - Control Rods Withdrawn Test measures the critical boron concentration at hot zero power (HZP). With all rods out, the lead control bank is at or near its fully withdrawn position. HZP is where the core is critical (k_{eff} = 1.0), and the Reactor Coolant System (RCS) is at design temperature and pressure for zero power. Performance of this test should not violate any of the referenced LCOs.

b. The Critical Boron Concentration - Control Rods Inserted Test measures the critical boron concentration at HZP, with a bank having a worth of at least 1% $\Delta k/k$ when fully inserted into the core. This test is used to measure the boron reactivity coefficient. With the core at HZP and all banks fully withdrawn, the boron concentration of the reactor coolant is gradually lowered in a continuous manner. The selected bank is then inserted to make up for the decreasing boron

(continued)

BASES

BACKGROUND (continued)

concentration until the selected bank has been moved over its entire range of travel. The reactivity resulting from each incremental bank movement is measured with a reactivity computer. The difference between the measured critical boron concentration with all rods fully withdrawn and with the bank inserted is determined. The boron reactivity coefficient is determined by dividing the measured bank worth by the measured boron concentration difference. Performance of this test could violate LCO 3.1.4, "Rod Group Alignment Limits"; LCO 3.1.5, "Shutdown Bank Insertion Limit"; or LCO 3.1.6, "Control Bank Insertion Limits."

c. The Control Rod Worth Test is used to measure the differential and integral reactivity worths of selected control banks or individual rods. This test is performed at HZP. The Boron Exchange Method, varies the reactor coolant boron concentration and moves the selected control bank in response to the changing boron concentration. The reactivity changes are measured with a reactivity computer. This data is used to determine the integral and differential worths of individual banks and rods. Performance of this test could violate LCO 3.1.4, LCO 3.1.5, or LCO 3.1.6.

d. The ITC Test measures the ITC of the reactor. This test is performed at HZP and consists of varying RCS temperature in a slow and continuous manner. The reactivity change is measured with a reactivity computer as a function of the temperature change. The ITC is the slope of the reactivity versus the temperature plot. The test is repeated by reversing the direction of the temperature change, and the final ITC is the average of the two calculated ITCs. Performance of this test could violate LCO 3.4.2, "RCS Minimum Temperature for Criticality."

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The fuel is protected by LCOs that preserve the initial conditions of the core assumed during the safety analyses. The above mentioned PHYSICS TESTS, and other tests that may be required to calibrate nuclear instrumentation or to diagnose operational problems, may require the operating control or process variables to deviate from their LCO limitations.

The UFSAR defines requirements for initial testing of the facility, including PHYSICS TESTS. Table 14.2.6-2 summarizes the zero, low power, and power tests. Although these PHYSICS TESTS are generally accomplished within the limits for all LCOs, conditions may occur when one or more LCOs must be suspended to make completion of PHYSICS TESTS possible or practical. This is acceptable as long as the fuel design criteria are not violated. When one or more of the requirements specified in LCO 3.1.3, "Moderator Temperature Coefficient (MTC)," LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the power level is limited to ≤ 5% RTP, the reactor coolant temperature is kept ≥ 530ºF, and SDM is within the limits provided in the COLR.

The PHYSICS TESTS include measurement of core nuclear parameters or the exercise of control components that affect process variables. Among the process variables involved are AFD and QPTR, which represent initial conditions of the unit safety analyses. Also involved are the movable control components (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR. PHYSICS TESTS meet the criteria for inclusion in the Technical Specifications, since the components and process variable LCOs suspended during PHYSICS TESTS meet Criteria 1, 2, and 3 of the NRC Policy Statement.

LCO

This LCO allows the reactor parameters of MTC and minimum temperature for criticality to be outside their specified limits. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. Operation beyond specified

(continued)

BASES

LCO (continued)

limits is permitted for the purpose of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

The requirements of LCO 3.1.3, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 may be suspended during the performance of PHYSICS TESTS provided:

a. RCS lowest loop average temperature is ≥ 530ºF;

b. SDM is within the limits provided in the COLR; and

c. THERMAL POWER is ≤ 5% RTP.

APPLICABILITY

This LCO is applicable in MODE 2 when performing low power PHYSICS TESTS. The applicable PHYSICS TESTS are performed in MODE 2 at HZP.

ACTIONS

A.1 and A.2

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

B.1

When THERMAL POWER is > 5% RTP, the only acceptable action is to open the reactor trip breakers (RTBs) to prevent operation of the reactor beyond its design limits. Immediately opening the RTBs will shut down the reactor and prevent operation of the reactor outside of its design limits.

(continued)

BASES

ACTIONS (continued)

C.1

When the RCS lowest T_{avg} is < 530ºF, the appropriate action is to restore T_{avg} to within its specified limit. The allowed Completion Time of 15 minutes provides time for restoring T_{avg} to within limits without allowing the plant to remain in an unacceptable condition for an extended period of time. Operation with the reactor critical and with temperature below 530EF could violate the assumptions for accidents analyzed in the safety analyses.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within an additional 15 minutes. The Completion Time of 15 additional minutes is reasonable, based on operating experience, for reaching MODE 3 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

The power range and intermediate range neutron detectors must be verified to by OPERABLE in MODE 2 by LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation." A CHANNEL OPERATIONAL TEST is performed on each power range and intermediate range channel within 7 days prior to initiation of the PHYSICS TESTS. This will ensure that the RPS is properly aligned to provide the required degree of core protection during the performance of PHYSICS TESTS. The 7 day time limit is sufficient to ensure that the instrumentation is OPERABLE before initiating PHYSICS TESTS.

SR 3.1.8.2

Verification that the RCS lowest loop T_{avg} is ≥ 530ºF will ensure that the unit is not operating in a condition that could invalidate the safety analyses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.8.3

Verification that the THERMAL POWER is ≤ 5% RTP will ensure that the plant is not operating in a condition that could invalidate the safety analyses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.1.8.4

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

REFERENCES	1.	10 CFR 50, Appendix B, Section XI.
	2.	10 CFR 50.59.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Heat Flux Hot Channel Factor ($F_Q(X,Y,Z)$)

BASES

BACKGROUND

The purpose of the limits on the values of $F_Q(X,Y,Z)$ is to limit the local (i.e., pellet) peak power density. The value of $F_Q(X,Y,Z)$ varies both radially and along the axial height of the core.

$F_Q(X,Y,Z)$ is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and fuel rod dimensions. Therefore, $F_Q(X,Y,Z)$ is a measure of the peak fuel pellet power within the reactor core.

During power operation, the global power distribution is limited by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which are directly and continuously measured process variables. These LCOs, along with LCO 3.1.6, "Control Bank Insertion Limits," maintain the core limits on power distributions on a continuous basis.

$F_Q(X,Y,Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution and to a lesser extent, with boron concentration and moderator temperature.

$F_Q(X,Y,Z)$ is measured periodically using the incore detector system. These measurements are generally taken with the core at or near steady state conditions.

Using the measured three dimensional power distributions, it is possible to derive a measured value for $F_Q(X,Y,Z)$. However, because this value represents a steady state condition, it does not include the variations in the value of $F_Q(X,Y,Z)$ that are present during nonequilibrium situations, such as load following.

To account for these possible variations, the $F_Q(X,Y,Z)$ limit is reduced by precalculated factors to account for perturbations from steady state conditions to the operating limits.

Core monitoring and control under nonsteady state conditions are accomplished by operating the core within the limits of

(continued)

BASES

BACKGROUND (continued)

the appropriate LCOs, including the limits on AFD, QPTR, and control rod insertion.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident (LOCA), the peak cladding temperature must not exceed 2200ºF (Ref. 1);

b. The DNBR calculated for the hottest fuel rod in the core must be above the approved DNBR limit (Ref. 2). (The LCO alone is not sufficient to preclude DNB criteria violations for certain accidents, i.e,. accidents in which the event itself changes the core power distribution. For these events, additional checks are made in the core reload design process against the permissible statepoint power distributions.);

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 230 cal/gm, and no fuel melting may occur (Ref. 3); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 4).

Limits on $F_Q(X,Y,Z)$ ensure that the value of the initial total peaking factor assumed in the accident analyses remains valid. Other LOCA acceptance criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, the peak cladding temperature is typically most limiting.

$F_Q(X,Y,Z)$ limits assumed in the LOCA analysis are typically limiting relative to (i.e., lower than) the $F_Q(X,Y,Z)$ limit assumed in safety analyses for other postulated accidents. Therefore, this LCO provides conservative limits for other postulated accidents.

$F_Q(X,Y,Z)$ satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

The Heat Flux Hot Channel Factor, $F_Q(X,Y,Z)$, shall be limited by the following relationships:

$$F_Q^M(X,Y,Z) \leq \frac{F_Q^{RTP}}{P} K(Z) \qquad \text{for } P > 0.5$$

$$F_Q^M(X,Y,Z) \leq \frac{F_Q^{RTP}}{0.5} K(Z) \qquad \text{for } P \leq 0.5$$

where: F_Q^{RTP} is the $F_Q(X,Y,Z)$ limit at RTP provided in the COLR, and is reduced by K(BU), measurement uncertainty, and manufacturing tolerances provided in the COLR.

K(Z) is the normalized $F_Q(X,Y,Z)$ as a function of core height provided in the COLR, and

$$P = \frac{\text{THERMAL POWER}}{\text{RTP}}$$

For this facility, the actual values of F_Q^{RTP}, K(BU), and K(Z) are given in the COLR.

For relaxed AFD limit operation, $F_Q^M(X,Y,Z)$ (measured $F_Q(X,Y,Z)$) is compared against three limits:

- Steady state limit, $(F_Q^{RTP}/P) * K(Z) * K(BU)$,
  - P is the fractional power level if THERMAL POWER > 50%, and is 0.5 if THERMAL POWER ≤ 50%
- Transient operational limit, $F_Q^L(X,Y,Z)^{OP}$, and
- Transient RPS limit, $F_Q^L(X,Y,Z)^{RPS}$.

A steady state evaluation requires obtaining an incore flux map in MODE 1. From the incore flux map results we obtain the measured value, $F_Q^M(X,Y,Z)$, of $F_Q(X,Y,Z)$. Then, $F_Q^M(X,Y,Z)$ is compared to the steady state limit, which includes the K(Z) and K(BU) terms. The measured value shall be increased by the manufacturing tolerance and measurement uncertainty.

K(BU) is the normalized $F_Q^L(X,Y,Z)$ as a function of burnup and is provided in the COLR.

(continued)

BASES

LCO (continued)

$F_Q^L(X,Y,Z)^{OP}$ and $F_Q^L(X,Y,Z)^{RPS}$ are cycle dependent design limits to ensure the $F_Q(X,Y,Z)$ is met during transients. The expression for $F_Q^L(X,Y,Z)^{OP}$ is:

$$F_Q^L(X,Y,Z)^{OP} = F_Q^D(X,Y,Z) * M_Q(X,Y,Z) / (UMT * MT)$$

where: $F_Q^L(X,Y,Z)^{OP}$ is the cycle dependent maximum allowable design peaking factor which ensures that the $F_Q(X,Y,Z)$ limit will be preserved for operation within the LCO limits. $F_Q^L(X,Y,Z)^{OP}$ includes allowances for calculational and measurement uncertainties.

$F_Q^D(X,Y,Z)$ is the design power distribution for F_Q provided in the COLR.

$M_Q(X,Y,Z)$ is the margin remaining in core location X,Y,Z to the LOCA limit in the transient power distribution and is provided in the COLR for normal operating conditions and power escalation testing during startup operations. UMT and MT are only included in the calculation of $F_Q^L(X,Y,Z)^{OP}$ if these factors were not included in the LOCA limit.

UMT is the measurement uncertainty specified in the COLR.

MT is the engineering hot channel factor (or manufacturing tolerance factor) specified in the COLR.

The expression for $F_Q^L(X,Y,Z)^{RPS}$ is:

$$F_Q^L(X,Y,Z)^{RPS} = F_Q^D(X,Y,Z) * M_C(X,Y,Z) / (UMT * MT)$$

where: $F_Q^L(X,Y,Z)^{RPS}$ is the cycle dependent maximum allowable design peaking factor which ensures that the centerline fuel melt limit will be preserved for operation within the LCO limits. $F_Q^L(X,Y,Z)^{RPS}$ includes allowances for calculational and measurement uncertainties.

$M_C(X,Y,Z)$ is the margin remaining to the centerline fuel melt limit in core location X,Y,Z from the transient power distribution and is provided in the COLR for normal operating conditions and power escalation testing during startup operations. UMT and MT are only included in the calculation of $F_Q^L(X,Y,Z)^{RPS}$ if these factors were not included in the fuel melt limit.

(continued)

BASES

LCO (continued)

The $F_Q(X,Y,Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures above 2200ºF during either a large or small break LOCA.

This LCO requires operation within the bounds assumed in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within the LOCA $F_Q(X,Y,Z)$ limits. If $F_Q(X,Y,Z)$ cannot be maintained within the LCO limits, reduction of the core power, power range neutron flux – high trip setpoint, and overpower ΔT trip setpoint are required.

Violating the LCO limits for $F_Q(X,Y,Z)$ produces unacceptable consequences if a design basis event occurs while $F_Q(X,Y,Z)$ is outside its specified limits.

APPLICABILITY

The $F_Q(X,Y,Z)$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power. The exception to this is the steam line break event, which is assumed for analysis purposes to occur from very low power levels. At these low power levels, measurements of $F_Q(X,Y,Z)$ are not sufficiently reliable. Operation within analysis limits at these conditions is inferred from startup physics testing verification of design predictions of core parameters in general.

(continued)

BASES (continued)

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q^M(X,Y,Z)$ exceeds its steady state limit, maintains an acceptable absolute power density. $F_Q^M(X,Y,Z)$ is the measured value of $F_Q(X,Y,Z)$ and is adjusted for measurement uncertainty and manufacturing tolerances. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time.

A.2

A reduction of the Power Range Neutron Flux - High trip setpoints by ≥ 1% for each 1% by which $F_Q^M(X,Y,Z)$ exceeds its steady state limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1.

A.3

Reduction in the Overpower ΔT trip setpoint (value of K_4) by ≥ 1% for each 1% by which $F_Q^M(X,Y,Z)$ exceeds its steady state limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions since the transient response is limited by the setpoint reduction. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period, and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1.

A.4

Verification that $F_Q^M(X,Y,Z)$ has been restored to within its steady state limit, by performing SR 3.2.1.1, SR 3.2.1.2, and SR 3.2.1.3 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, ensures that core conditions during operation at higher power levels are consistent with safety analyses assumptions. Since $F_Q^M(X,Y,Z)$ exceeds the steady state limit, the transient operational limit and possibly the transient RPS limit may be exceeded. By performing SR 3.2.1.2 and SR 3.2.1.3, appropriate actions with respect to reductions in AFD limits,

(continued)

ACTIONS (continued)

THERMAL POWER, Power Range Neutron Flux – High trip setpoints and OPΔT trip setpoints will be performed ensuring that core conditions during operational and Condition 2 transients are maintained within the assumptions of the safety analysis.

B.1 and B.2

The operational margin during transient operations is based on the relationship between $F_Q^M(X,Y,Z)$ and the transient operational limit, $F_Q^L(X,Y,Z)^{OP}$, as follows:

$$\text{\% Operational Margin} = \left(1 - \frac{F_Q^M(X,Y,Z)}{F_Q^L(X,Y,Z)^{OP}}\right) * 100\%$$

If the operational margin is less than zero, then $F_Q^M(X,Y,Z)$ is greater than $F_Q^L(X,Y,Z)^{OP}$ and there exists a potential for exceeding the peak local power assumed in the core in a LOCA or in the limiting Condition 2 transient where the event itself does not cause changes in the power distribution. If the margin is less than zero, then a reduction in the AFD limits and/or the THERMAL POWER level is performed as specified in the COLR. Performing the actions within the allowed Completion Time of 4 hours restricts the axial flux distribution and THERMAL POWER such that even if a transient occurred, core peaking factors are not exceeded. Adjusting the transient operational limit by the equivalent change in AFD limits establishes the appropriate revised surveillance limits.

B.3 and B.4

If a COLR-specified reduction in THERMAL POWER is required, the Power Range Neutron Flux – High trip and Overpower ΔT trip setpoints are reduced by greater than or equal to the magnitude of the power reduction required in Action B.2 as a conservative action to protect against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding reduction in AFD limits and THERMAL POWER required by Actions B.1 and B.2.

B.5

A flux map is required to verify the acceptability of $F_Q^M(X,Y,Z)$ prior to increasing THERMAL POWER above the reduced level imposed by Action B.2.

(continued)

BASES

ACTIONS (continued)

C.1

The margin contained within the reactor protection system (RPS) Overpower ΔT trip setpoints during transient operations is based on the relationship between $F_Q^M(X,Y,Z)$ and the RPS limit, $F_Q^L(X,Y,Z)^{RPS}$, as follows:

$$\% \text{ RPS Margin} = \left(1 - \frac{F_Q^M(X,Y,Z)}{F_Q^L(X,Y,Z)^{RPS}}\right) * 100\%$$

If the RPS margin is less than zero, then $F_Q^M(X,Y,Z)$ is greater than $F_Q^L(X,Y,Z)^{RPS}$ and there exists a potential for exceeding fuel melt limits during certain transient conditions. If the margin is less than zero, then the Overpower ΔT $f_2(\Delta I)$ breakpoints from the COLR are reduced by KSLOPE for each 1% that $F_Q^M(X,Y,Z)$ exceeds the RPS limit. The value of KSLOPE is specified in the COLR. This is a conservative action for protection against the consequences of transients since this adjustment limits the axial flux distribution which can be achieved during a transient and ensures the centerline fuel melt criterion is satisfied during normal operation and AOOs. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period.

D.1

If Required Actions of Condition A, B or C are not met within their associated Completion Times, the plant must be placed in a mode or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1, SR 3.2.1.2, and SR 3.2.1.3 each has a Frequency condition that requires verification that $F_Q^M(X,Y,Z)$ is within specified limits after achieving equilibrium conditions after a power rise of more than 10% RTP over the THERMAL POWER at which it was

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

last verified to be within specified limits. This requirement is modified by a note applicable to the first power ascension after a refueling. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map can be obtained. Because $F_Q^M(X,Y,Z)$ could not have previously been measured in this reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q^M(X,Y,Z)$ is made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the Frequency condition requiring verification of $F_Q^M(X,Y,Z)$ following a power increase of more than 10%, ensures that they are verified as soon as RTP (or any other level for extended operation) is achieved. In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days (or, for SR 3.2.1.1, the frequency specified in the Surveillance Frequency Control Program) without verification of $F_Q^M(X,Y,Z)$. The Frequency condition is not intended to require verification of these parameters after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which F_Q was last measured.

SR 3.2.1.1

Verification that $F_Q^M(X,Y,Z)$ is within its specified steady state limit involves increasing $F_Q^M(X,Y,Z)$ to allow for manufacturing tolerance, K(BU), and measurement uncertainties for the case where those factors are not included in the F_Q limit. For the case where these factors are included, a direct comparison of $F_Q^M(X,Y,Z)$ to the F_Q limit can be performed. $F_Q^M(X,Y,Z)$ is the measured value of $F_Q(X,Y,Z)$ obtained from incore flux map results. Values for the manufacturing tolerance, K(BU), and measurement uncertainty are specified in the COLR.

The limit with which $F_Q^M(X,Y,Z)$ is compared varies inversely with power above 50% RTP and directly with the functions K(BU) and K(Z) provided in the COLR.

For startups immediately following a refueling outage, determination of $F_Q^M(X,Y,Z)$ is required prior to THERMAL POWER exceeding 75% RTP. This ensures some determination of $F_Q^M(X,Y,Z)$ is made at a lower power level at which adequate margin is available before going to 100% RTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 (continued)

If THERMAL POWER has been increased by ≥ 10% RTP since the last determination of $F_Q^M(X,Y,Z)$, another evaluation of this factor is required 12 hours after reaching equilibrium conditions at this higher power level (to ensure that $F_Q^M(X,Y,Z)$ values have decreased sufficiently with power increase to stay within the LCO limits).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.2.1.2 and 3.2.1.3

The nuclear design process includes calculations performed to determine that the core can be operated within the $F_Q(X,Y,Z)$ limits during normal operational maneuvers. Because flux maps are taken in steady state conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the flux map data. These variations are, however, conservatively calculated by considering a wide range of unit maneuvers in normal operation. The maximum peaking factor increase over steady state values is determined by a maneuvering analysis (Ref. 5).

The limit with which $F_Q^M(X,Y,Z)$ is compared varies and is provided in the COLR. No additional uncertainties are applied to the measured $F_Q(X,Y,Z)$ because the limits already include uncertainties.

$F_Q^L(X,Y,Z)^{OP}$ and $F_Q^L(X,Y,Z)^{RPS}$ limits are not applicable for the following axial core regions, measured in percent of core height:

a. Lower core region, from 0 to 10% inclusive; and

b. Upper core region, from 90 to 100% inclusive.

The top and bottom 10% of the core are excluded from the evaluation because of the low probability that these regions would be more limiting in the safety analyses and because of the difficulty of making a precise measurement in these regions.

This Surveillance is modified by a note that may require that more frequent surveillances be performed. If $F_Q^M(X,Y,Z)$ is evaluated and found

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 and 3.2.1.3 (continued)

to be within the applicable transient limit, an evaluation is required to account for any increase to $F_Q^M(X,Y,Z)$ that may occur and cause the $F_Q(X,Y,Z)$ limit to be exceeded before the next required $F_Q(X,Y,Z)$ evaluation.

This evaluation requires trends in both the measured hot channel factor and in its operational and RPS limits to be extrapolated. Two extrapolations are performed for each of these two limits:

1. The first extrapolation determines whether the measured heat flux hot channel factor is likely to exceed its limit prior to the next performance of the SR.

2. The second extrapolation determines whether, prior to the next performance of the SR, the ratio of the measured heat flux hot channel factor to the limit is likely to decrease below the value of that ratio when the measurement was taken.

Each of these extrapolations is applied separately to each of the operational and RPS heat flux hot channel factor limits. If both of the extrapolations for a given limit are unfavorable, i.e., if the extrapolated factor is expected to exceed the extrapolated limit and the extrapolated factor is expected to become a larger fraction of the extrapolated limit than the measured factor is of the current limit, additional actions must be taken. These actions are to meet the $F_Q(X,Y,Z)$ limit with the last $F_Q^M(X,Y,Z)$ increased by the appropriate factor specified in the COLR or to evaluate $F_Q(X,Y,Z)$ prior to the projected point in time when the extrapolated values are expected to exceed the extrapolated limits. These alternative requirements attempt to prevent $F_Q(X,Y,Z)$ from exceeding its limit prior to the next measurement without detection using the best available data. $F_Q^M(X,Y,Z)$ is not required to be extrapolated for the initial flux map taken after reaching equilibrium conditions since the initial flux map establishes the baseline measurement for future trending. Also, extrapolation of $F_Q^M(X,Y,Z)$ limits are not valid for core locations that were previously rodded, or for core locations that were previously within ±2% of the core height about the demand position of the rod tip.

For startups immediately following a refueling outage, determination of $F_Q^M(X,Y,Z)$ is required prior to THERMAL POWER exceeding 75% RTP. This ensures some determination of $F_Q^M(X,Y,Z)$ is made at a lower power level at which adequate margin is available before going to 100% RTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.2 and 3.2.1.3 (continued)

$F_Q(X,Y,Z)$ is verified at power levels ≥ 10% RTP above the THERMAL POWER of its last verification, 12 hours after achieving equilibrium conditions to ensure that $F_Q(X,Y,Z)$ is within its limit at higher power levels.

The Surveillance Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup. The Surveillance may be done more frequently if required by the results of $F_Q^M(X,Y,Z)$ evaluations.

The Frequency of 31 EFPD is adequate to monitor the change of power distribution because such a change is sufficiently slow, when the plant is operated in accordance with the TS, to preclude adverse peaking factors between 31 day surveillances.

REFERENCES

1. 10 CFR 50.46, 1974.
2. UFSAR Section 4.4.2.1.
3. UFSAR Section 15.4.8.
4. UFSAR Section 3.1.
5. DPC-NE-2011-P-A, "Nuclear Design Methodology Report for Core Operating Limits of Westinghouse Reactors".

Figure B 3.2.1B-1 (page 1 of 1)
K(Z) - Normalized $F_Q(Z)$ as a Function of Core Height

Deleted by Revision 86

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F_{\Delta H}(X,Y)$)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the power density at any point in the core so that the fuel design criteria are not exceeded and the accident analysis assumptions remain valid. The design limits on local (pellet) and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors, along with the other applicable LCOs, ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location during either normal operation or a postulated accident analyzed in the safety analyses.

$F_{\Delta H}(X,Y)$ is defined as the ratio of the integral of the linear power along the fuel rod with the highest integrated power to the average integrated fuel rod power. Therefore, $F_{\Delta H}(X,Y)$ is a measure of the maximum total power produced in a fuel rod.

$F_{\Delta H}(X,Y)$ is sensitive to fuel loading patterns, bank insertion, and fuel burnup. $F_{\Delta H}(X,Y)$ typically increases with control bank insertion and typically decreases with fuel burnup.

$F_{\Delta H}(X,Y)$ is not directly measurable but is inferred from a power distribution map obtained with the movable incore detector system. Specifically, the results of the three dimensional power distribution map are analyzed by a computer to determine $F_{\Delta H}(X,Y)$. This factor is calculated at least every 31 EFPD (or, for SR 3.2.2.1, the frequency specified in the Surveillance Frequency Control Program). However, during power operation, the global power distribution is monitored by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which address directly and continuously measured process variables.

The COLR provides peaking factor limits that ensure that the design basis value of the departure from nucleate boiling (DNB) is met for normal operation, operational transients, and any transient condition arising from events of moderate frequency for transients that do not alter the core power distribution. The DNB design basis for operational transients and transients of moderate frequency precludes DNB and is met by limiting the minimum local DNB heat flux ratio to greater than or equal to 1.141 or the corresponding statistical DNBR limit (Ref. 5) using the Siemens Power Corporation's (SPC's) DNB correlation (i.e., HTP).

(continued)

BASES

BACKGROUND (continued)

All DNB limited transient events are assumed to begin with an $F_{\Delta H}(X,Y)$ value that satisfies the LCO requirements. Operation outside the LCO limits may produce unacceptable consequences if a DNB limiting event occurs. The DNB design basis ensures that there is no overheating of the fuel that results in possible cladding perforation with the release of fission products to the reactor coolant.

APPLICABLE SAFETY ANALYSES

Limits on $F_{\Delta H}(X,Y)$ preclude core power distributions that exceed the following fuel design limits:

a. There must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition (Ref. 1) (The LCO alone is not sufficient to preclude DNB criteria violations for certain accidents, i.e., accidents in which the event itself changes the core power distribution. For these events, additional checks are made in the core reload design process against the permissible statepoint power distributions.);

b. During a large break loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200ºF;

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 230 cal/gm and no fuel melting may occur (Ref. 2); and

d. Fuel design limits required by HBRSEP Design Criteria (Ref. 3) for the condition when control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

For transients that may be DNB limited, the Reactor Coolant System flow and $F_{\Delta H}(X,Y)$ are the core parameters of most importance. The limits on $F_{\Delta H}(X,Y)$ ensure that the DNB design basis is met for normal operation, operational transients, and any transients arising from events of moderate frequency that do not alter the core power distribution. For transients such as uncontrolled RCCA bank withdrawal, which are characterized by changes in the core power distribution, this LCO alone is not sufficient to preclude DNB. The acceptability of the accident analyses is ensured by LCO 3.2.3, “AXIAL FLUX DIFFERENCE (AFD),” LCO 3.1.6, “Control Bank Insertion Limits,” LCO 3.2.4, “QUADRANT POWER TILT RATIO (QPTR),” and LCO 3.4.1, “RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits,” in combination with cycle-specific analytical calculations. The DNB design basis is met by limiting the minimum DNBR to the 95/95 DNB criterion of 1.141 or the corresponding statistical DNBR limit (Ref. 5) using the HTP correlation. This value provides a high degree of assurance that the hottest fuel rod in the core does not experience a DNB.

The allowable $F_{\Delta H}(X,Y)$ limit increases with decreasing power level. This functionality in $F_{\Delta H}(X,Y)$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, any DNB events in which the calculation of the core limits is modeled implicitly use this variable value of $F_{\Delta H}(X,Y)$ in the analyses.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The LOCA safety analysis indirectly models $F_{\Delta H}(X,Y)$ as an input parameter. The Nuclear Heat Flux Hot Channel Factor ($F_Q(X,Y,Z)$) and the axial peaking factors are inserted directly into the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 4).

The fuel is protected in part by Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid. The following LCOs ensure this: LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F_{\Delta H}(X,Y)$)," and LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(X,Y,Z)$)."

$F_{\Delta H}(X,Y)$ and $F_Q(X,Y,Z)$ are measured periodically using the movable incore detector system. Measurements are generally taken with the core at, or near, steady state conditions. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion Limits.

$F_{\Delta H}(X,Y)$ satisfies Criterion 2 of the NRC Policy Statement.

LCO

$F_{\Delta H}(X,Y)$ shall be maintained within the limits provided in the COLR.

The $F^{L}_{\Delta H}(X,Y)^{LCO}$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least heat removal capability and thus the highest probability for a DNB.

$F^{L}_{\Delta H}(X,Y)^{LCO}$ limits are maximum allowable radial peak (MARP) limits which are developed in accordance with NRC-approved Duke Energy methodology (Ref. 5). MARP limits are constant DNBR limits which are a function of both the magnitude and location of the axial peak, F(Z), therefore, justifying the X,Y dependence of the $F^{L}_{\Delta H}(X,Y)^{LCO}$ limit.

The limiting value, $F^{L}_{\Delta H}(X,Y)^{LCO}$, is described by the equation contained in the COLR.

(continued)

BASES

LCO (continued)

A power multiplication factor in this equation includes an additional margin for higher radial peaking from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value, $F^{L}_{\Delta H}(X,Y)^{LCO}$, is allowed to increase by (1 / RRH)% for every 1% RTP reduction in THERMAL POWER. RRH is the amount by which allowable THERMAL POWER must be reduced for each 1% that $F_{\Delta H}(X,Y)$ exceeds the limit. The specific value is contained in the COLR. This increase in the LCO limit is due to the reduced amount of heat removal required at lower powers.

APPLICABILITY

The $F_{\Delta H}(X,Y)$ limits must be maintained in MODE 1 to preclude core power distributions from exceeding the fuel design limits for DNBR and PCT. Applicability in other modes is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F_{\Delta H}(X,Y)$ in other modes (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F_{\Delta H}(X,Y)$ in these modes. The exceptions to this are the steam line break and uncontrolled RCCA bank withdrawal events, which are assumed for analysis purposes to occur from very low power levels. At these power levels, measurements of $F_{\Delta H}(X,Y)$ are not sufficiently reliable. Operation within analysis limits at these conditions is inferred from startup physics testing verification of design predictions of core parameters in general.

ACTIONS

A.1

If $F_{\Delta H}(X,Y)$ is not within its limit, THERMAL POWER must be reduced at least RRH% from RTP for each 1% $F_{\Delta H}(X,Y)$ exceeds the limit. Reducing power increases the DNB margin and does not likely cause the DNBR limit to be violated in steady state operation. The Completion Time of 2 hours provides an acceptable time to reach the required power level without allowing the plant to remain in an unacceptable condition for an extended period of time.

Condition A is modified by a Note that requires that Required Actions A.3.2.2 and A.4 must be completed whenever Condition A is entered. Thus, if compliance with the LCO is restored, Required Action A.3.2.2 and A.4 nevertheless requires another measurement and calculation of $F_{\Delta H}(X,Y)$ in accordance with SR 3.2.2.1.

(continued)

BASES

ACTIONS (continued)

A.2.1 and A.2.2

Upon completion of the power reduction in Required Action A.1, the unit is allowed an additional 6 hours to restore $F_{\Delta H}(X,Y)$ to within its RTP limits. This restoration may, for example, involve realigning any misaligned rods enough to bring $F_{\Delta H}(X,Y)$ within its limit. When the $F_{\Delta H}(X,Y)$ limit is exceeded, the DNBR limit is not likely to be violated in steady state operation, because events that could significantly perturb the $F_{\Delta H}(X,Y)$ value (e.g., static control rod misalignment) are considered in the safety analyses. However, the DNBR limit may be violated if a DNB limiting event occurs. Thus, the allowed completion time of 8 hours provides an acceptable time to restore $F_{\Delta H}(X,Y)$ to within its RTP limits without allowing the plant to remain in an unacceptable condition for an extended period of time.

If the value of $F_{\Delta H}(X,Y)$ is not restored to within its specified RTP limit, the alternative option is to reduce the Power Range Neutron Flux – High Trip Setpoint ≥ RRH% for each 1% $F^{M}_{\Delta H}(X,Y)$ exceeds the limit in accordance with Required Action A.2.2. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin and limits the consequences of a transient by limiting the transient power level which can be achieved during a postulated event.

The allowed Completion Time of 8 hours to reset the trip setpoints per Required Action A.2.2 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and there is no urgent need to reduce the trip setpoints. This is a sensitive operation that may inadvertently trip the Reactor Protection System.

A.3.1, A.3.2.1, and A.3.2.2

If $F_{\Delta H}(X,Y)$ was not restored to within the RTP limits, and the Power Range Neutron Flux – High Trip Setpoints were subsequently reduced, an additional 64 hours are provided to restore $F_{\Delta H}(X,Y)$ within the limit for RTP. Alternatively, the Overtemperature ΔT setpoint (K_1 term) must be reduced by ≥ TRH for each 1% $F^{M}_{\Delta H}(X,Y)$ exceeds the limit. TRH, which is provided in the COLR, is the amount of overtemperature ΔT K_1 setpoint reduction required to compensate for each 1% that $F^{M}_{\Delta H}(X,Y)$ exceeds the limit. This action ensures that protection margin is maintained in the reduced power level for DNB related transients not covered by the reduction in the Power Range Neutron Flux – High Trip Setpoint. Once the Overtemperature ΔT Trip Setpoint has been reduced per Required Action A.3.2.1, Action A.3.2.2 requires an incore flux map (SR 3.2.2.1) to

(continued)

BASES

ACTIONS

A.3.1, A.3.2.1, and A.3.2.2 (continued)

be obtained and the measured value of $F_{\Delta H}(X,Y)$ verified not to exceed the allowed limit at the lower power level.

The unit is provided 64 additional hours to perform these tasks over and above the 8 hours allowed by either Action A.2.1 or Action A.2.2. The Completion Time of 72 hours is acceptable because of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 72-hour period. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the incore flux map, perform the required calculations, and evaluate $F^M_{\Delta H}(X,Y)$.

A.4

Verification that $F_{\Delta H}(X,Y)$ is within its specified limits after an out of limit occurrence ensures that the cause that led to the $F_{\Delta H}(X,Y)$ exceeding its limit is corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F_{\Delta H}(X,Y)$ limit is within the LCO limits prior to exceeding 50% RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is ≥ 95% RTP.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced prior to performing this Action.

B.1

When Required Actions A.1.1 through A.4 cannot be completed within their required Completion Times, the plant must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience regarding the time required to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1 and SR 3.2.2.2 each has a Frequency condition that requires verification that $F^M_{\Delta H}(X,Y)$ is within the specified limits after achieving equilibrium conditions after a power rise of more than 10% RTP over the THERMAL POWER at which it was last verified to be within specified limits. This requirement is modified by a note applicable to the first power ascension after refueling. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

power distribution map can be obtained. Because $F^M_{\Delta H}(X,Y)$ could not have been previously measured in this reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_{\Delta H}(X,Y)$ is made at lower power levels at which adequate margin is available before going to 100% RTP. The Frequency condition is not intended to require verification of the parameter after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which $F_{\Delta H}(X,Y)$ was last measured.

SR 3.2.2.1

The value of $F^M_{\Delta H}(X,Y)$ is determined by using the movable incore detector system to obtain a flux distribution map at any THERMAL POWER greater than 5% RTP. A computer program is used to process the measured 3-D power distribution to calculate the steady state $F^L_{\Delta H}(X,Y)^{LCO}$ limit which is compared against $F^M_{\Delta H}(X,Y)$.

After each refueling, $F^M_{\Delta H}(X,Y)$ must be determined in MODE 1 prior to exceeding 75% RTP. This requirement ensures that $F_{\Delta H}(X,Y)$ limits are met at the beginning of each fuel cycle. $F^M_{\Delta H}(X,Y)$ is verified at power levels ≥ 10% RTP above the THERMAL POWER of its last verification, 12 hours after achieving equilibrium conditions to ensure that $F^M_{\Delta H}(X,Y)$ is within its limit at high power levels.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.2.2.2

The nuclear design process includes calculations performed to determine that the core can be operated within the $F_{\Delta H}(X,Y)$ limits during normal operational maneuvers. Because flux maps are taken in steady state conditions, the variations in power distribution resulting from normal operational maneuvers are not present in the flux map data. These variations are, however, conservatively calculated by considering a wide range of unit maneuvers in normal operation. The maximum peaking factor increase over steady state values is a limit called $F^L_{\Delta H}(X,Y)^{SURV}$.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.2 (continued)

This Surveillance compares the measured $F^M_{\Delta H}(X,Y)$ to the Surveillance limit to ensure that safety analysis limits are maintained.

This Surveillance has been modified by a Note that may require that more frequent surveillances be performed. If $F^M_{\Delta H}(X,Y)$ is evaluated and found to be within its surveillance limit, an evaluation is required to account for any increase to $F^M_{\Delta H}(X,Y)$ that may occur and cause the $F^L_{\Delta H}(X,Y)^{SURV}$ limit to be exceeded before the next required $F_{\Delta H}(X,Y)$ evaluation.

This evaluation requires trends in both the measured hot channel factor and its surveillance limit to be extrapolated. Two extrapolations are performed for this limit:

1. The first extrapolation determines whether the measured enthalpy rise hot channel factor is likely to exceed its surveillance limit prior to the next performance of the SR.

2. The second extrapolation determines whether, prior to the next performance of the SR, the ratio of the measured enthalpy rise hot channel factor to the surveillance limit is likely to decrease below the value of that ratio when the measurement was taken.

Each of these extrapolations is applied separately to the enthalpy rise hot channel factor surveillance limit. If both of the extrapolations are unfavorable, i.e., if the extrapolated factor is expected to exceed the extrapolated limit and the extrapolated factor is expected to become a larger fraction of the extrapolated limit than the measured factor is of the current limit, additional actions must be taken. These actions are to meet the $F^M_{\Delta H}(X,Y)$ limit with the last $F^M_{\Delta H}(X,Y)$ increased by a factor specified in the COLR, or to evaluate $F^M_{\Delta H}(X,Y)$ prior to the point in time when the extrapolated values are expected to exceed the extrapolated limits. These alternative requirements attempt to prevent $F^M_{\Delta H}(X,Y)$ from exceeding its limit for any significant period of time without detection using the best available data. $F^M_{\Delta H}(X,Y)$ is not required to be extrapolated for the initial flux map taken after reaching equilibrium conditions since the initial flux map establishes the baseline measurement for future trending.

After each refueling, $F_{\Delta H}(X,Y)$ must be determined in MODE 1 prior to exceeding 75% RTP. This requirement ensures that $F_{\Delta H}(X,Y)$ limits are

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.2 (continued)

met at the beginning of each fuel cycle. $F^M_{\Delta H}(X,Y)$ is verified at power levels 10% above the THERMAL POWER of its last verification, 12 hours after achieving equilibrium conditions to ensure that $F^M_{\Delta H}(X,Y)$ is within its limit at high power levels.

The 31 EFPD Frequency is acceptable because the power distribution changes relatively slowly over this amount of fuel burnup. Accordingly, this Frequency is short enough that the $F_{\Delta H}(X,Y)$ limit cannot be exceeded for any significant period of operation.

REFERENCES

1. UFSAR Section 4.4.2.1.
2. UFSAR Section 15.4.8.
3. UFSAR Section 3.1.
4. 10 CFR 50.46.
5. DPC-NE-2005-PA, "Thermal-Hydraulic Statistical Core Design Methodology."

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL FLUX DIFFERENCE (AFD)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the axial power distribution skewing to either the top or bottom of the core. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in axial power distribution control.

The analysis performed to develop the AFD limits involves the generation and evaluation of several thousand, three-dimensional power distributions which consider burnup, reactor power, coolant temperature, control bank position and xenon. The generation of conservative limits is assured through the generation of power distributions which are more severe than expected to occur during normal or transient operation. The selection of severe xenon distributions for the peaking analysis also adds another degree of conservatism to the analysis. Subsequently, power peaking factors and power distributions are examined to ensure that the loss of coolant accident (LOCA), DNB limiting transients in which the power distribution remains unchanged during the transient, and anticipated transient limits are met. Violation of the AFD limits invalidate the conclusions of the accident and transient analyses with regard to fuel cladding integrity.

Although the maneuvering analysis defines limits that must be met to satisfy safety analyses, typically a target operating band is used to control axial power distribution in day-to-day operation. The maneuvering analysis assumes that the core is generally operated (depleted) within this band at HFP, which requires that the AFD be controlled within a narrow tolerance band around a burnup dependent target.

The constant target band operating space is typically smaller and lies within the maneuvering analysis operating space. Control within the constant target band operating space constrains the variation of axial xenon distributions and axial power distributions during normal operation and unit maneuvers. The maneuvering analysis calculations assume a wide range of xenon distributions and then confirm that the resulting power distributions satisfy the requirements of the accident analyses.

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The AFD is a measure of axial power distribution skewing to the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution and, to a lesser extent, reactor coolant temperature and boron concentrations. The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

The maneuvering analysis (Ref. 1) uses a three-dimensional nodal reactor model to calculate a set of power distributions at several times in the core life. These power distributions are calculated with abnormal xenon distributions to ensure predicted power distributions are conservative with respect to those expected to occur. Peaking factors from these power distributions are then evaluated against various thermal limits. This evaluation then confirms the adequacy of current power dependent AFD limits, rod insertion limits, and the F(ΔI) penalty function, or provides the bases for establishing new limits. The development of operational AFD limits and the F(ΔI) function of either the Overpower ΔT the Overtemperature ΔT RPS trip functions are established to exclude the power distributions that exceed the respective thermal limits.

The limits on the AFD ensure that the Heat Flux Hot Channel Factor (F_Q(X,Y,Z)) is not exceeded during either normal operation or in the event of xenon redistribution following power changes. The limits on the AFD also limit the range of power distributions that are assumed as initial conditions in analyzing Condition 2, 3, and 4 events. This ensures that fuel cladding integrity is maintained for the postulated accidents in Chapter 15 of the UFSAR.

The limits on the AFD satisfy Criterion 2 of the NRC Policy Statement.

LCO

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator, through either the manual operation of the control banks, or automatic motion of control banks responding to

(continued)

BASES

LCO (continued)

temperature deviations resulting from either manual operation of the Chemical and Volume Control System to change boron concentration, or from power level changes.

Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors (Ref. 2). Separate signals are taken from the top and bottom detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom excore detector in each detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as %Δ flux or %ΔI.

Part A of this LCO is modified by a Note that states the conditions necessary for declaring the AFD outside of the applicable limits. The AFD limits are defined in the COLR.

Violating the LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its limits.

APPLICABILITY

AFD requirements are applicable in MODE 1 at greater than or equal to 50% RTP, when the combination of THERMAL POWER and core peaking factors are the core parameters of primary importance in safety analyses.

For AFD limits developed using maneuvering analysis methodology, the the value of the AFD does not affect the limiting accident consequences with THERMAL POWER < 50% RTP and for lower operating power MODES.

ACTIONS

A.1

As an alternative to restoring the AFD to within its specified limits, Required Action A.1 requires a THERMAL POWER reduction to < 50% RTP. This places the core in a condition for which the value of the AFD is not important in the applicable safety analyses. A Completion Time of 30 minutes is reasonable, based on operating experience, to reach 50% RTP without challenging plant systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

The AFD is monitored on an automatic basis using the unit process computer that has an AFD monitor alarm. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm message immediately if the AFDs for two or more OPERABLE excore channels are outside the limits specified in the COLR.

This Surveillance verifies that the AFD as indicated by the NIS excore channels is within the specified limits and consistent with the status of the AFD monitor alarm. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. With the AFD monitor alarm inoperable, the AFD is monitored every hour to detect operation outside its limit. The Frequency of 1 hour is based on operating experience regarding the amount of time required to vary the AFD, and the fact that the AFD is closely monitored.

REFERENCES

1. DPC-NE-2011-P-A, "Nuclear Design Methodology Report for Core Operating Limits of Westinghouse Reactors."

2. UFSAR Section 7.2.1.1

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BASES

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Figure B 3.2.3A-1 (Page 1 of 1)
AXIAL FLUX DIFFERENCE Acceptable Operation Limits
and Target Band Limits as a Function
of RATED THERMAL POWER

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B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made during startup testing, after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, and LCO 3.1.6, "Control Bank Insertion Limits," provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident, the peak cladding temperature must not exceed 2200ºF (Ref. 1);

b. The DNBR calculated for the hottest fuel rod in the core must be above the approved DNBR limit (Ref. 2). (The LCO alone is not sufficient to preclude DNB criteria violations for certain accidents, i.e., accidents in which the event itself changes the core power distribution. For these events, additional checks are made in the core reload design process against the permissible statepoint power distributions.);

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 230 cal/gm and no fuel melting may occur (Ref. 3); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 4).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(X,Y,Z)$), the Nuclear Enthalpy Rise Hot

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Channel Factor ($F_{\Delta H}(X,Y)$), and control bank insertion are established to preclude core power distributions that exceed the safety analyses limits.

The QPTR limits ensure that $F_{\Delta H}(X,Y)$ and $F_Q(X,Y,Z)$ remain below their limiting values by preventing an undetected change in the gross radial power distribution.

In MODE 1, the $F_{\Delta H}(X,Y)$ and $F_Q(X,Y,Z)$ limits must be maintained to preclude core power distributions from exceeding design limits assumed in the safety analyses.

The QPTR satisfies Criterion 2 of the NRC Policy Statement.

LCO

The QPTR limit of 1.02, at which corrective action is required, provides a margin of protection for both the DNB ratio and linear heat generation rate contributing to excessive power peaks resulting from X-Y plane power tilts. A limiting QPTR of 1.02 can be tolerated before the margin for uncertainty in $F_Q(X,Y,Z)$ and $F_{\Delta H}(X,Y)$, or safety analysis peaking assumptions are possibly challenged.

APPLICABILITY

The QPTR limit must be maintained in MODE 1 with THERMAL POWER > 50% RTP to prevent core power distributions from exceeding the design limits.

Applicability in MODE 1 ≤ 50% RTP and in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require the implementation of a QPTR limit on the distribution of core power. The QPTR limit in these conditions is, therefore, not important. Note that the $F_{\Delta H}(X,Y)$ and $F_Q(X,Y,Z)$ LCOs still apply, but allow progressively higher peaking factors at 50% RTP or lower.

The Applicability is modified by a Note which states that the LCO is not applicable until the excore nuclear instrumentation is calibrated subsequent to a refueling. This refers to the final excore nuclear instrumentation calibration performed at ≥ 75% RTP and not any interim calibrations.

(continued)

BASES

ACTIONS

A.1

With the QPTR exceeding its limit, a power level reduction of 3% RTP for each 1% by which the QPTR exceeds 1.02 is a conservative tradeoff of total core power with peak linear power. The Completion Time of 2 hours allows sufficient time to identify the cause and correct the tilt. Note that the power reduction itself may cause a change in the tilted condition.

A.2

After completion of Required Action A.1, the QPTR alarm may still be in its alarmed state. As such, any additional changes in the QPTR are detected by requiring a check of the QPTR at the reduced power level once per 12 hours thereafter (SR 3.2.4.1). If the QPTR continues to increase, THERMAL POWER has to be further reduced accordingly. A 12 hour Completion Time is sufficient because any additional change in QPTR would be relatively slow.

A.3

The peaking factors $F_{\Delta H}(X,Y)$ and $F_Q(X,Y,Z)$ are of primary importance in ensuring that the power distribution remains consistent with the initial conditions used in the safety analyses. Performing SRs on $F_{\Delta H}(X,Y)$ and $F_Q(X,Y,Z)$ within the Completion Time of 24 hours ensures that these primary indicators of power distribution are within their respective limits. A Completion Time of 24 hours takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and perform a flux map. If these peaking factors are not within their limits, the Required Actions of these Surveillances provide an appropriate response for the abnormal condition. If the QPTR remains above its specified limit, the peaking factor surveillances are required each 7 days thereafter to evaluate $F_{\Delta H}(X,Y)$ and $F_Q(X,Y,Z)$ with changes in power distribution. Relatively small changes are expected due to either burnup and xenon redistribution or correction of the cause for exceeding the QPTR limit.

A.4

Although $F_{\Delta H}(X,Y)$ and $F_Q(X,Y,Z)$ are of primary importance as initial conditions in the safety analyses, other changes in the power distribution may occur as the QPTR limit is exceeded

(continued)

BASES

ACTIONS

A.4 (continued)

and may have an impact on the validity of the safety analysis. A change in the power distribution can affect such reactor parameters as bank worths and peaking factors for rod malfunction accidents. When the QPTR exceeds its limit, it does not necessarily mean a safety concern exists. It does mean that there is an indication of a change in the gross radial power distribution that requires an investigation and evaluation that is accomplished by examining the incore power distribution. Specifically, the core peaking factors and the quadrant tilt must be evaluated because they are the factors that best characterize the core power distribution. This re-evaluation is required to ensure that, before increasing THERMAL POWER to above the more restrictive limit of Required Action A.1 or A.2, the reactor core conditions are consistent with the assumptions in the safety analyses. Should Required Actions A.1, A.2, and A.3 result in restoration of QPTR within its limit, LCO 3.2.4 is satisfied, and Condition A can be exited prior to completion of Required Action A.4.

A.5

If the QPTR has exceeded the 1.02 limit and a re-evaluation of the safety analysis is completed and shows that safety requirements are met, the excore detectors are normalized to eliminate the indicated tilt prior to increasing THERMAL POWER to above the more restrictive limit of Required Action A.1 or A.2. This is done to detect any subsequent significant changes in QPTR.

Required Action A.5 is modified by a Note that states that the indicated tilt is not eliminated until after the re-evaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). This Note is intended to prevent any ambiguity about the required sequence of actions.

A.6

Once the excore detectors are normalized to eliminate the indicated tilt (i.e., Required Action A.5 is performed), it

(continued)

BASES

ACTIONS

A.6 (continued)

is acceptable to return to full power operation. However, as an added check that the core power distribution at RTP is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(X,Y,Z)$ and $F_{\Delta H}(X,Y)$ are within their specified limits within 24 hours of reaching RTP. As an added precaution, if the core power does not reach RTP within 24 hours, but is increased slowly, then the peaking factor surveillances must be performed within 48 hours of the time when the more restrictive of the power level limit determined by Required Action A.1 or A.2 is exceeded. These Completion Times are intended to allow adequate time to increase THERMAL POWER to above the more restrictive limit of Required Action A.1 or A.2, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

Required Action A.6 is modified by a Note that states that the peaking factor surveillances may only be done after the excore detectors have been normalized to remove the tilt (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are normalized to remove the tilt and the core returned to power.

B.1

If Required Actions A.1 through A.6 are not completed within their associated Completion Times, the unit must be brought to a MODE or condition in which the requirements do not apply. To achieve this status, THERMAL POWER must be reduced to ≤ 50% RTP within 4 hours. The allowed Completion Time of 4 hours is reasonable, based on operating experience regarding the amount of time required to reach the reduced power level without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1

SR 3.2.4.1 is modified by two Notes. Note 1 allows QPTR to be calculated with three power range channels if THERMAL POWER is < 75% RTP and the input from one Power Range Neutron Flux channel is inoperable. Note 2 allows

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.4.1 (continued)

performance of SR 3.2.4.2 in lieu of SR 3.2.4.1.

This Surveillance verifies that the QPTR, as indicated by the Nuclear Instrumentation System (NIS) excore channels or Emergency Response Facility Information System (ERFIS), is within its limits. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.2.4.2

This Surveillance is modified by a Note, which states that it is not required until 12 hours after the input from one or more Power Range Neutron Flux channels are inoperable and the THERMAL POWER is ≥ 75% RTP.

With an NIS power range channel inoperable, tilt monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

For purposes of monitoring the QPTR when one power range channel is inoperable, the moveable incore detectors are used to confirm that the normalized symmetric power distribution is consistent with the indicated QPTR and any previous data indicating a tilt.

The symmetric thimble flux map can be used to generate symmetric thimble "tilt." This can be compared to a reference symmetric thimble tilt, from the most recent full

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.4.2 (continued)

core flux map, to generate an incore QPTR. Therefore, the incore QPTR can be used to confirm that QPTR is within limits.

With one NIS channel inoperable, the indicated tilt may be changed from the value indicated with all four channels OPERABLE. To confirm that no change in tilt has actually occurred, which might cause the QPTR limit to be exceeded, the incore result may be compared against previous flux maps either using the symmetric thimbles as described above or a complete flux map. Nominally, quadrant tilt from the Surveillance should be within 2% of the tilt shown by the most recent flux map data.

REFERENCES

1. 10 CFR 50.46.
2. UFSAR Section 4.4.2.1.
3. UFSAR Section 15.4.8.
4. UFSAR Section 3.1.

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during Anticipated Operational Occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as specifying LCOs on other reactor system parameters and equipment performance.

The LSSS, defined in this specification as the Allowable Values, in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits during Design Basis Accidents (DBAs).

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits are:

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling (DNB);

2. Fuel centerline melt shall not occur; and

3. The RCS pressure SL of 2735 psig shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 50.67 limits during AOOs.

Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit during accidents is that offsite dose shall be maintained within an acceptable fraction of 10 CFR 50.67 limits. Different accident categories are allowed a

(continued)

BACKGROUND (continued)

different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RPS instrumentation is segmented into four distinct but interconnected modules as illustrated in the UFSAR, Chapter 7 (Ref. 1), and as identified below:

1. Field transmitters or process sensors: provide a measurable electronic signal based upon the physical characteristics of the parameter being measured;

2. Signal Process Control and Protection System, including Analog Protection System, Nuclear Instrumentation System (NIS), field contacts, and protection channel sets: provides signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system channels, and control board/control room/miscellaneous indications;

3. RPS relay logic: initiates proper unit shutdown and/or ESF actuation in accordance with the defined logic, which is based on the bistable outputs from the signal process control and protection system; and

4. Reactor trip switchgear, including reactor trip breakers (RTBs) and bypass breakers: provides the means to interrupt power to the control rod drive mechanisms (CRDMs) and allows the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

<u>Field Transmitters or Sensors</u>

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Nominal Trip Setpoint (NTSP) and

(continued)

BACKGROUND

Field Transmitters or Sensors (continued)

Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria.

Signal Process Control and Protection System

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with NTSP derived from Analytical Limits established by the safety analyses. Analytical Limits are defined in UFSAR, Chapter 7 (Ref. 1), Chapter 6 (Ref. 2), and Chapter 15 (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the RPS relay logic. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the RPS relay logic, while others provide input to the RPS relay logic, the main control board, the unit computer, and one or more control systems.

The instrumentation system is designed in accordance with HBRSEP design criteria, which is described in UFSAR Section 3.1 (Ref. 4), and IEEE-279-1968 (Ref. 5).

The instrumentation system is designed such that a failure or malfunction of a control system, that is assumed in the initiation of an accident or transient and concurrently prevents proper action of one or more instrument channels required to mitigate the same accident or transient, will not preclude the proper protection system action. The remaining portions of the instrumentation system are designed to ensure the protection system action occurs to mitigate the accident or transient (i.e., no single failure within the instrumentation system sill prevent proper protection system action when required). These requirements are described in Reference 5.

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BACKGROUND

Signal Process Control and Protection System (continued)

Two logic channels are required to ensure no single random failure of a logic channel will disable the RPS. The logic channels are designed such that testing required while the reactor is at power may be accomplished without causing trip.

Nominal Trip Setpoints and Allowable Values

The Nominal Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted (in accordance with the Nominal Trip Setpoint) when the "as left" value is within the established calibration tolerance band. A channel is required to be adjusted, if the actual Nominal Trip Setpoint is found outside the "as found" calibration tolerance band, such that the actual Trip Setpoint is within the "as left" calibration tolerance band. The as-left tolerance and as-found tolerance band methodology is provided in EGR-NGGC-0153, Engineering Instrument Setpoints.

The Nominal Trip Setpoints used in the bistables are based on the analytical limits stated in Reference 3. The selection of these Nominal Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays accounted for in setpoint calculations and accident analyses are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those RPS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 6), the Nominal Trip Setpoints and Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Nominal Trip Setpoints, including their explicit uncertainties, is provided in the company setpoint methodology procedure (Ref. 8). The actual Nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT.

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BACKGROUND

Trip Setpoints and Allowable Values (continued)

Notes allow the Nominal Trip Setpoints to be reduced when required by Required Actions.

NTSPs, in conjunction with the use of as-found and as-left tolerances, together with the requirements of the Allowable Value ensure that SLs are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed). Note that in the accompanying LCO 3.3.1, the Allowable Values are the LSSS.

Each channel of the analog protection system can be tested on line to verify that the signal or setpoint accuracy is within the specified allowance requirements of calculations performed in accordance with the company setpoint methodology procedure (Ref. 8). Once a designated channel is taken out of service for testing, a simulated signal is injected into the channel for testing. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section.

The Nominal Trip Setpoints and Allowable Values listed in Table 3.3.1-1 are based on the methodology described in the company setpoint methodology procedure (Ref. 8), which incorporates all of the applicable uncertainties for each channel. The magnitudes of these uncertainties are factored into the determination of each Nominal Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Reactor Protection System Relay Logic

This equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of RPS logic, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide reactor trip for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in

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BACKGROUND

Reactor Protection System Relay Logic (continued)

its own cabinets for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to trip in the event of a loss of power, directing the unit to a safe shutdown condition.

The relay logic performs the decision logic for actuating a reactor trip, generates the electrical output signal that will initiate the required trip, and provides the status, permissive, and annunciator output signals to the main control room of the unit.

The bistable outputs from the signal processing equipment are sensed by the relay logic equipment and combined into logic matrices that represent combinations indicative of various unit upset and accident transients. If a required logic matrix combination is completed, the system will initiate a reactor trip. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Reactor Trip Switchgear

The RTBs are in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening of the RTBs interrupts power to the CRDMs, which allows the shutdown rods and control rods to fall into the core by gravity. Each RTB is equipped with a bypass breaker to allow testing of the RTB while the unit is at power. During normal operation the output from the RPS relay logic is a voltage signal that energizes the undervoltage coils in the RTBs and bypass breakers, if in use. When the required logic matrix combination is completed, the RPS relay logic output voltage signal is removed, the undervoltage coils are de-energized, the breaker trip lever is actuated by the de-energized undervoltage coil, and the RTBs and bypass breakers are tripped open. This allows the shutdown rods and control rods to fall into the core. In addition to the de-energization of the undervoltage coils, each RTB is also equipped with a shunt trip device that is energized to trip the breaker open upon receipt of a reactor trip signal from the RPS relay logic. Either the undervoltage coil or the

(continued)

BACKGROUND

Reactor Trip Switchgear (continued)

shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism.

The RPS relay logic matrix Functions are described in the functional diagrams included in Reference 1. In addition to the reactor trip or ESF, these diagrams also describe the various "permissive interlocks" that are associated with unit conditions. When an RPS train is removed from service for testing, the other train is relied upon to provide the automatic reactor protection requirements.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RPS functions to preserve the SLs during all AOOs and mitigates the consequences of DBAs in all MODES in which the RTBs are closed.

Each of the analyzed accidents and transients can be detected by one or more RPS Functions. The accident analysis described in Reference 3 takes credit for most RPS trip Functions. RPS trip Functions that are retained yet not specifically credited in the accident analysis are implicitly credited in the safety analysis and the NRC staff approved licensing basis for the unit. These RPS trip Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. They may also serve as backups to RPS trip Functions that were credited in the accident analysis.

The LCO requires all instrumentation performing an RPS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation Function, two channels of Manual Reactor Trip in each logic Function, and two trains in each Automatic Trip Logic Function. The two-out-of-three and two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing a reactor trip. Specific exceptions to the above general philosophy exist and are discussed below.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Reactor Protection System Functions

The safety analyses and OPERABILITY requirements applicable to each RPS Function are discussed below:

1. Manual Reactor Trip

The Manual Reactor Trip ensures that the control room operator can initiate a reactor trip at any time by using either of two reactor trip push buttons in the control room. A Manual Reactor Trip accomplishes the same results as any one of the automatic trip Functions. It is used by the reactor operator to shut down the reactor whenever any RPS or Engineered Safety Features Actuation System (ESFAS) parameter is rapidly trending toward its Trip Setpoint.

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip push button. Each channel activates the reactor trip breaker in both trains. Two independent channels are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Function.

In MODE 1 or 2, manual initiation of a reactor trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the manual initiation Function must also be OPERABLE if the shutdown rods or control rods are withdrawn since withdrawn rods are required to insert to satisfy SDM requirements in those MODES. With the Control Rod Drive (CRD) System capable of withdrawing the shutdown rods or the control rods in MODE 3, 4, or 5, inadvertent control rod withdrawal is possible. Therefore, manual reactor trip is also required in this condition. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the RTBs are open. If the RTBs are open, there is no need to be able to trip the reactor because all of the rods are inserted. This requirement maintains maximum shutdown margin available in the event of a reactivity excursion while in MODES 3, 4, or 5. In MODE 6, neither the shutdown rods nor the control rods are

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Manual Reactor Trip (continued)

permitted to be withdrawn and the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function is not required.

2. Power Range Neutron Flux

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS power range detectors provide input to the Rod Control System and the Turbine Control System. Therefore, the actuation logic must be able to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

a. Power Range Neutron Flux - High

The Power Range Neutron Flux - High trip Function ensures that protection is provided, from all power levels, against a positive reactivity excursion leading to DNB during power operations. These can be caused by rod withdrawal or reductions in RCS temperature.

The LCO requires all four of the Power Range Neutron Flux - High channels to be OPERABLE.

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux - High trip must be OPERABLE. This Function will terminate the reactivity excursion and shut down the reactor prior to reaching a power level that could damage the fuel. In MODE 3, 4, 5, or 6, the NIS power range detectors cannot detect neutron levels in this range. In these MODES, the Power Range Neutron Flux - High does not have to be OPERABLE because the reactor is shut down and reactivity excursions into the power range

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Power Range Neutron Flux - High (continued)

are extremely unlikely. Other RPS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

b. Power Range Neutron Flux - Low

The LCO requirement for the Power Range Neutron Flux - Low trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions.

The LCO requires all four of the Power Range Neutron Flux - Low channels to be OPERABLE.

In MODE 1, below the Power Range Neutron Flux (P-10 setpoint), and in MODE 2, the Power Range Neutron Flux - Low trip must be OPERABLE. This Function may be manually blocked by the operator when two out of four power range channels are greater than approximately 10% RTP (P-10 setpoint). This Function is automatically unblocked when three out of four power range channels are below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the Power Range Neutron Flux - High trip Function.

In MODE 3, 4, 5, or 6, the Power Range Neutron Flux - Low trip Function does not have to be OPERABLE because the reactor is shut down and the NIS power range detectors cannot detect neutron levels in this range. Other RPS trip Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux trip Function provides backup protection against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides backup protection to the Power Range Neutron Flux - Low Setpoint trip Function. The NIS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS intermediate range detectors do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

The LCO requires two channels of Intermediate Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function.

Because this trip Function is important only during startup, there is generally no need to disable channels for testing while the Function is required to be OPERABLE. Therefore, a third channel is unnecessary.

In MODE 1 below the P-10 setpoint, and in MODE 2, when there is a potential for an uncontrolled RCCA bank rod withdrawal accident during reactor startup, the Intermediate Range Neutron Flux trip must be OPERABLE. Above the P-10 setpoint, the Power Range Neutron Flux - High Setpoint trip provides core protection for a rod withdrawal accident. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because the control rods must be ≤ 5 steps withdrawn and only the shutdown rods may be fully withdrawn. The reactor cannot be started up in this condition. The core also has the required SDM to mitigate the consequences of a positive reactivity addition accident. In MODE 6, all rods are fully inserted and the core has a required increased SDM. Also, the NIS intermediate range detectors cannot detect neutron levels present in this MODE.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4. Source Range Neutron Flux

The LCO requirement for the Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux - Low Setpoint and Intermediate Range Neutron Flux trip Functions. In MODES 3, 4, and 5, administrative controls also prevent the uncontrolled withdrawal of rods. The NIS source range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RPS automatic protection function required in MODES 3, 4, and 5. Therefore, the functional capability at the specified Trip Setpoint is assumed to be available.

The LCO requires two channels of Source Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function. The LCO also requires one channel of the Source Range Neutron Flux to be OPERABLE in MODE 3, 4, or 5 with RTBs open. In this case, the source range Function is to provide control room indication. The outputs of the Function to RPS logic are not required OPERABLE when the RTBs are open.

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical, boron dilution and control rod ejection events. The Function also provides visual neutron flux indication and alarm in the control room.

In MODE 2 when below the P-6 setpoint during a reactor startup, the Source Range Neutron Flux trip must be OPERABLE. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux - Low Setpoint trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the NIS source range detectors are de-energized and inoperable.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Source Range Neutron Flux (continued)

In MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal, or if one or more rods are not fully inserted, the Source Range Neutron Flux trip Function must also be OPERABLE. In this condition, the Source Range Neutron Flux trip must be OPERABLE to provide core protection against a rod withdrawal, boron dilution, or steam line break accident. If the RTBs are open, the source range detectors are not required to trip the reactor. However, their monitoring Function must be OPERABLE to monitor core neutron levels and provide indication of reactivity changes that may occur as a result of events like a boron dilution. The requirements for the NIS source range detectors in MODE 6 are addressed in LCO 3.9.2, "Nuclear Instrumentation."

5. Overtemperature ΔT

The Overtemperature ΔT trip Function is provided to ensure that the design limit DNBR is met. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include pressurizer pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system. The Function monitors both variation in power and flow since a decrease in flow has the same effect on ΔT as a power increase. The Overtemperature ΔT trip Function uses each loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature - the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;

- pressurizer pressure - the Trip Setpoint is varied to correct for changes in system pressure; and

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Overtemperature ΔT (continued)

- axial power distribution – $f_1(\Delta I)$, the Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the design limit, as indicated by the difference between the upper and lower NIS power range detectors, the Trip Setpoint is reduced in accordance with Note 1 of Table 3.3.1-1.

Dynamic compensation is included for system piping delays from the core to the temperature measurement system and RTD response time.

The Overtemperature ΔT trip Function is calculated for each loop as described in Note 1 of Table 3.3.1-1. Trip occurs if Overtemperature ΔT is indicated in two loops. The function $(1+\tau_1 s)/(1+\tau_2 s)$; is generated by the lead-lag controller for T_{avg} dynamic compensation and $f_1(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests. The shape of the $f_1(\Delta I)$ penalty is described in the Core Operating Limits Report (COLR). Note that this Function also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a reactor trip.

The LCO requires all three channels of the Overtemperature ΔT trip Function to be OPERABLE. Note that the Overtemperature ΔT Function receives input from channels shared with other RPS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Overtemperature ΔT (continued)

trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

6. Overpower ΔT

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also limits the required range of the Overtemperature ΔT trip Function and provides a backup to the Power Range Neutron Flux - High Setpoint trip. The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature - the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature; and
- rate of change of reactor coolant average temperature - including dynamic compensation for the delays between the core and the temperature measurement system.
- axial power distribution – $f_2(\Delta I)$, the Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the design limit, as indicated by the difference between the upper and lower NIS power range detectors, the Trip Setpoint is reduced in accordance with Note 2 of of Table 3.3.1-1.

The Overpower ΔT trip Function is calculated for each loop as per Note 2 of Table 3.3.1-1. Trip occurs if Overpower ΔT is indicated in two loops. The function $(\tau_3 s)/(1+\tau_3 s)$; is generated by the rate-lag controller for T_{avg} dynamic compensation and τ_3 is the time

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

6. Overpower ΔT (continued)

constant utilized in the rate-lag controller for T_{avg}. The shape of the $f_2(\Delta I)$ penalty is described in the Core Operating Limits Report (COLR).
Note that this Function also provides a signal to generate a turbine runback prior to reaching the Allowable Value. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overpower ΔT condition and may prevent a reactor trip.

The LCO requires three channels of the Overpower ΔT trip Function to be OPERABLE. Note that the Overpower ΔT trip Function receives input from channels shared with other RPS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overpower ΔT trip Function must be OPERABLE. These are the only times that enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

7. Pressurizer Pressure

The same sensors provide input to the Pressurizer Pressure - High and - Low trips and the Overtemperature ΔT trip.

a. Pressurizer Pressure - Low

The Pressurizer Pressure - Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure.

The LCO requires three channels of Pressurizer Pressure - Low to be OPERABLE.

In MODE 1, when DNB is a major concern, the Pressurizer Pressure - Low trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock (NIS power range P-10 or turbine impulse pressure greater

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Pressurizer Pressure - Low (continued)

than approximately 10% of full power equivalent (P-7 input)). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, no conceivable power distributions can occur that would cause DNB concerns.

b. Pressurizer Pressure - High

The Pressurizer Pressure - High trip Function ensures that protection is provided against overpressurizing the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions.

The LCO requires three channels of the Pressurizer Pressure - High to be OPERABLE.

The Pressurizer Pressure - High LSSS is selected to be below the pressurizer safety valve actuation pressure and above the power operated relief valve (PORV) setting. This setting minimizes challenges to safety valves while avoiding unnecessary reactor trip for those pressure increases that can be controlled by the PORVs.

In MODE 1 or 2, the Pressurizer Pressure - High trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure - High trip Function does not have to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. Additionally, low temperature overpressure protection systems provide overpressure protection when below MODE 4.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

8. Pressurizer Water Level - High

The Pressurizer Water Level - High trip Function provides a backup signal for the Pressurizer Pressure - High trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. The LCO requires three channels of Pressurizer Water Level - High to be OPERABLE. The pressurizer level channels are used as input to the Pressurizer Level Control System. The level channels do not actuate the safety valves, and the high pressure reactor trip is set below the safety valve setting. Therefore, with the slow rate of charging available, pressure overshoot due to level channel failure cannot cause the safety valve to lift before reactor high pressure trip.

In MODE 1, when there is a potential for overfilling the pressurizer, the Pressurizer Water Level - High trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock. On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions.

9. Reactor Coolant Flow - Low

a. Reactor Coolant Flow - Low (Single Loop)

The Reactor Coolant Flow - Low (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in one or more RCS loops, while avoiding reactor trips due to normal variations in loop flow. Above the P-8 setpoint, which is approximately 40% RTP, a loss of flow in any RCS loop will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.The LCO requires three Reactor Coolant Flow - Low

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Reactor Coolant Flow - Low (Single Loop) (continued)

channels per loop to be OPERABLE in MODE 1 above P-8.

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core. In MODE 1 below the P-8 setpoint, a loss of flow in two or more loops is required to actuate a reactor trip (Function 9.b) because of the lower power level and the greater margin to the design limit DNBR.

b. Reactor Coolant Flow - Low (Two Loops)

The Reactor Coolant Flow - Low (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in two or more RCS loops while avoiding reactor trips due to normal variations in loop flow.

Above the P-7 setpoint and below the P-8 setpoint, a loss of flow in two or more loops will initiate a reactor trip. Each loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow - Low channels per loop to be OPERABLE.

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the Reactor Coolant Flow - Low (Two Loops) trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on low flow in two or more RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any one loop will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

10. Reactor Coolant Pump (RCP) Breaker Position

Both RCP Breaker Position trip Functions operate together on two sets of auxiliary contacts, with one set on each RCP breaker. These Functions anticipate the Reactor Coolant Flow - Low trips to avoid RCS heatup that would occur before the low flow trip actuates.

a. Reactor Coolant Pump Breaker Position (Single Loop)

The RCP Breaker Position (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in one RCS loop. The position of each RCP breaker is monitored. If one RCP breaker is open above the P-8 setpoint, a reactor trip is initiated. This trip Function will generate a reactor trip before the Reactor Coolant Flow - Low (Single Loop) Trip Setpoint is reached.

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this trip Function because the RCS Flow - Low trip alone provides sufficient protection of unit SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of a pump.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setting with which to associate an LSSS.

In MODE 1 above the P-8 setpoint, when a loss of flow in any RCS loop could result in DNB conditions in the core, the RCP Breaker Position (Single Loop) trip must be OPERABLE. In MODE 1 below the P-8 setpoint, a loss of flow in two or more loops is required to actuate a reactor trip because of the lower power level and the greater margin to the design limit DNBR.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABLILITY (continued)

b. Reactor Coolant Pump Breaker Position (Two Loops)

The RCP Breaker Position (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The position of each RCP breaker is monitored. Above the P-7 setpoint and below the P-8 setpoint, two or more RCP Breakers open will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow - Low (Two Loops) Trip Setpoint is reached.

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this Function because the RCS Flow - Low trip alone provides sufficient protection of unit SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of an RCP.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setting with which to associate an LSSS.

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the RCP Breaker Position (Two Loops) trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any one loop will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

11. Undervoltage Reactor Coolant Pumps

The Undervoltage RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The voltage to each RCP is monitored. Above the P-7 setpoint, a loss of voltage detected on two or more RCP buses will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow - Low (Two Loops) Trip Setpoint is reached. Time delays are incorporated into the Undervoltage RCPs channels to prevent reactor trips due to momentary electrical power transients.

The LCO requires one Undervoltage RCP channel per bus to be OPERABLE.

In MODE 1 above the P-7 setpoint, the Undervoltage RCP trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled. This Function shares relays with the Auxiliary Feedwater "Undervoltage Reactor Coolant Pump" Function, which starts the steam driven auxiliary feedwater (SDAFW) pump.

12. Underfrequency Reactor Coolant Pumps

The Underfrequency RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops from a major network frequency disturbance. An underfrequency condition will slow down the pumps, thereby reducing their coastdown time following a pump trip. The proper coastdown time is required so that reactor heat can be removed immediately after reactor trip. The frequency of each RCP bus is monitored. Above the P-7 setpoint, a loss of frequency detected on two or more RCP buses will initiate a trip of all RCPs. This trip Function will generate a reactor trip through the RCP breaker position trip logic before the Reactor Coolant Flow - Low (Two Loops) Trip Setpoint is reached. Time delays are incorporated into the

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

12. Underfrequency Reactor Coolant Pumps (continued)

Underfrequency RCPs channels to prevent reactor trips due to momentary electrical power transients.

The LCO requires one Underfrequency RCP channel per bus to be OPERABLE.

In MODE 1 above the P-7 setpoint, the Underfrequency RCPs trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled.

13. Steam Generator Water Level - Low Low

The Steam Generator (SG) Water Level - Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the Auxiliary Feedwater (AFW) System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low low level in any SG is indicative of a loss of heat sink for the reactor. The level transmitters provide input to the SG Level Control System. This Function also performs the ESFAS function of starting the AFW pumps on low low SG level.

The LCO requires three channels of SG Water Level - Low Low per SG to be OPERABLE.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level - Low Low trip must be OPERABLE. The normal source of water for the SGs is the Main Feedwater (MFW) System (not safety related). The MFW System is in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the MFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level - Low Low Function does not have to be OPERABLE because the reactor is not

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

13. Steam Generator Water Level - Low Low (continued)

operating or even critical. Decay heat removal is accomplished by the AFW and MFW Systems in MODE 3 and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6.

14. DELETED

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

14. DELETED

15. Turbine Trip

a. Turbine Trip - Low Fluid Oil Pressure

The Turbine Trip - Low Fluid Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip Function acts to minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the P-8 setpoint, approximately 40% power, will not actuate a reactor trip. Three pressure switches monitor the auto-stop oil pressure in the Turbine Trip System. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure - High trip Function and RCS integrity is ensured by the pressurizer safety valves.

The LCO requires three channels of Turbine Trip - Low Fluid Oil Pressure to be OPERABLE in MODE 1 above P-8.

Below the P-8 setpoint, a turbine trip does not actuate a reactor trip. In MODE 3, 4, 5, or 6, there is no potential for a turbine trip, and the Turbine Trip - Low Fluid Oil Pressure trip Function does not need to be OPERABLE.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

b. Turbine Trip - Turbine Stop Valve Closure

The Turbine Trip - Turbine Stop Valve Closure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip from a power level above the P-8 setpoint, approximately 40% power. This action will actuate a reactor trip. The trip Function anticipates the loss of secondary heat removal capability that occurs when the stop valves close. Tripping the reactor in anticipation of loss of secondary heat removal acts to minimize the pressure and temperature transient on the reactor. This trip Function will not and is not required to operate in the presence of a single channel failure. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure - High trip Function, and RCS integrity is ensured by the pressurizer safety valves. This trip Function is diverse to the Turbine Trip - Low Fluid Oil Pressure trip Function. Each turbine stop valve is equipped with one limit switch that inputs to the RPS. If both limit switches indicate that the stop valves are closed, a reactor trip is initiated.

The limit switches are set to assure channel trip occurs when the associated stop valve is closed.

The LCO requires two Turbine Trip - Turbine Stop Valve Closure channels, one per valve, to be OPERABLE in MODE 1 above P-8. Both channels must trip to cause reactor trip.

Below the P-8 setpoint, a load rejection can be accommodated by the Steam Dump System. In MODE 3, 4, 5, or 6, there is no potential for a load rejection, and the Turbine Trip - Stop Valve Closure trip Function does not need to be OPERABLE.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

16. Safety Injection Input from Engineered Safety Feature Actuation System

The SI Input from ESFAS ensures that if a reactor trip has not already been generated by the RPS, the ESFAS automatic actuation logic will initiate a reactor trip upon any signal that initiates SI. This is a condition of acceptability for the LOCA. However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a reactor trip is initiated every time an SI signal is present.

Trip Setpoint and Allowable Values are not applicable to this Function. The SI Input is provided by relay in the ESFAS. Therefore, there is no measurement signal with which to associate an LSSS.

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

17. Reactor Protection System Interlocks

Reactor protection interlocks are provided to ensure reactor trips are in the correct configuration for the current unit status. They back up operator actions to ensure protection system Functions are not bypassed during unit conditions under which the safety analysis assumes the Functions are not bypassed. Therefore, the interlock Functions do not need to be OPERABLE when the associated reactor trip functions are outside the applicable MODES. These are:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when any NIS intermediate range

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Intermediate Range Neutron Flux, P-6 (continued)

channel goes approximately one decade above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. When the source range trip is blocked, the high voltage to the detectors is also removed; and

- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the NIS Source Range Neutron Flux reactor trip.

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux reactor trip will be blocked, and this Function will no longer be necessary.

In MODE 3, 4, 5, or 6, the P-6 interlock does not have to be OPERABLE because the NIS Source Range is providing core protection.

b. Low Power Reactor Trips Block, P-7

The Low Power Reactor Trips Block, P-7 interlock is actuated by input from either the Power Range Neutron Flux, P-10, or the Turbine Impulse Pressure interlock. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Low Power Reactor Trips Block, P-7 (continued)

(1) on increasing power, the P-7 interlock automatically enables reactor trips on the following Functions:

- Pressurizer Pressure - Low;
- Pressurizer Water Level - High;
- Reactor Coolant Flow - Low (Two Loops);
- RCPs Breaker Open (Two Loops); and
- Undervoltage RCPs.

These reactor trips are only required when operating above the P-7 setpoint (approximately 10% power). The reactor trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of providing sufficient natural circulation without any RCP running.

(2) on decreasing power, the P-7 interlock automatically blocks reactor trips on the following Functions:

- Pressurizer Pressure - Low;
- Pressurizer Water Level - High;
- Reactor Coolant Flow - Low (Two Loops);
- RCP Breaker Position (Two Loops); and
- Undervoltage RCPs.

Trip Setpoint and Allowable Value are not applicable to the P-7 interlock because it is a logic Function and thus has no parameter with which to associate an LSSS.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Low Power Reactor Trips Block, P-7 (continued)

The P-7 interlock is a logic Function with train and not channel identity. Therefore, the LCO requires one channel per train of Low Power Reactor Trips Block, P-7 interlock to be OPERABLE in MODE 1.

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below 10% power, which is in MODE 1.

c. Power Range Neutron Flux, P-8

The Power Range Neutron Flux, P-8 interlock is actuated at approximately 40% power as determined by two-out-of-four NIS power range detectors. The P-8 interlock automatically enables the Turbine Trip, and Reactor Coolant Flow-Low (Single Loop) and RCP Breaker Position (Single Loop) reactor trips on low flow in one or more RCS loops on increasing power. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than approximately 40% power. On decreasing power, the reactor trip on Turbine Trip and low flow in any loop is automatically blocked.

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1. In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

d. Power Range Neutron Flux, P-10

The Power Range Neutron Flux, P-10 interlock is actuated at approximately 10% power, as

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Power Range Neutron Flux, P-10 (continued)

determined by two-out-of-four NIS power range detectors. If power level falls below 10% RTP on 3 of 4 channels, the power range low flux and intermediate range high flux trips will be automatically unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip. Note that blocking the reactor trip also blocks the signal to prevent automatic and manual rod withdrawal;

- on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux - Low reactor trip;

- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux reactor trip, and also to de-energize the NIS source range detectors;

- the P-10 interlock provides one of the two inputs to the P-7 interlock; and

- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux-Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2.

OPERABILITY in MODE 1 ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must be OPERABLE in MODE 2 to ensure that core protection is provided during a startup or shutdown by the Power Range Neutron Flux - Low

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Power Range Neutron Flux, P-10 (continued)

and Intermediate Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection.

e. Turbine Impulse Pressure

The Turbine Impulse Pressure sends a signal to P-7 when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the rated full power pressure. This is determined by one-out-of-two pressure detectors. The LCO requirement for this Function ensures that one of the inputs to the P-7 interlock is available. The LCO requires two channels of Turbine Impulse Pressure to be OPERABLE in MODE 1.

The Turbine Impulse Pressure channels must be OPERABLE when the turbine generator is operating. The Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not electrically loaded.

18. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of individual trip mechanisms. The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of a trip breaker and bypass breaker associated with a single RPS logic train that are racked in, closed, and capable of supplying power to the CRD System. Thus, the train may consist of the main breaker with the associated bypass breaker racked out (or removed from the cubicle), or the main breaker and bypass breaker, from a single train (when one train is out of service in accordance with LCO 3.3.1 ACTIONS). Two OPERABLE trains ensure no single random failure can disable the RPS trip capability.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

18. Reactor Trip Breakers (continued)

CRD System is capable of rod withdrawal, or one or more rods are not fully inserted.

19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the CRD System, or declared inoperable under Function 18 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the CRD System is capable of rod withdrawal, or one or more rods are not fully inserted.

20. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 18 and 19) and Automatic Trip Logic (Function 20) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. Each RTB is equipped with a bypass breaker to allow testing of the trip breaker while the unit is at power. The reactor trip signals generated by the RPS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RPS Automatic Trip Logic to be OPERABLE. Having two OPERABLE channels ensures that random failure of a single logic channel will not prevent reactor trip.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. The source range channel logic inputs are not required to be OPERABLE

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

20. Automatic Trip Logic (continued)

above the P-6 interlock. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the CRD System is capable of rod withdrawal, or one or more rods are not fully inserted.

The RPS instrumentation satisfies Criterion 3 of the NRC Policy Statement.

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.1-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all RPS protection Functions. Condition A addresses the situation where one or more required channels for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

(continued)

ACTIONS (continued)

B.1, B.2.1, and B.2.2

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation of the RPS for this Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. In this Condition, the remaining OPERABLE channel is adequate to perform the safety function.

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 additional hours (54 hours total time) followed by opening the RTBs within 1 additional hour (55 hours total time). The 6 additional hours to reach MODE 3 and the 1 hour to open the RTBs are reasonable, based on operating experience, to reach MODE 3 and open the RTBs from full power operation in an orderly manner and without challenging unit systems. With the RTBs open and the unit in MODE 3, this trip Function is no longer required to be OPERABLE.

C.1 and C.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 with the RTBs closed:

- Manual Reactor Trip;
- RTBs;
- RTB Undervoltage and Shunt Trip Mechanisms; and
- Automatic Trip Logic.

This action addresses the train orientation of the RPS for these Functions. With one channel or train inoperable, the inoperable channel or train must be restored to OPERABLE

(continued)

ACTIONS

C.1 and C.2 (continued)

status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be placed in a MODE in which the requirement does not apply. To achieve this status, the RTBs must be opened within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With the RTBs open, these Functions are no longer required.

The Completion Time is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function, and given the low probability of an event occurring during this interval.

D.1.1, D.1.2, D.2.1, D.2.2, and D.3

Condition D applies to the Power Range Neutron Flux - High Function.

The NIS power range detectors provide a two-out-of-four trip logic. A known inoperable channel must be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three logic for actuation. The 6 hours allowed to place the inoperable channel in the tripped condition is justified in WCAP-10271-P-A (Ref. 7).

In addition to placing the inoperable channel in the tripped condition, THERMAL POWER must be reduced to ≤ 75% RTP within 12 hours. Reducing the power level prevents operation of the core with radial power distributions beyond the design limits. With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost.

As an alternative to the above actions, the inoperable channel can be placed in the tripped condition within 6 hours and the QPTR monitored once every 12 hours as per SR 3.2.4.2, QPTR verification. Calculating QPTR every 12 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels ≥ 75% RTP. The

(continued)

ACTIONS

D.1.1, D.1.2, D.2.1, D.2.2, and D.3 (continued)

6 hour Completion Time and the 12 hour Frequency are consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Twelve hours are allowed to place the plant in MODE 3. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

Required Action D.2.2 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using the movable incore detectors once per 12 hours may not be necessary.

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux - Low;
- Overtemperature ΔT;
- Overpower ΔT;
- Pressurizer Pressure - High;
- SG Water Level - Low Low; and
- DELETED

A known inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition

(continued)

ACTIONS

E.1 and E.2 (continued)

requiring only one-out-of-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The 6 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 8.

If the inoperable channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.

F.1 and F.2

Condition F applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint and one channel is inoperable. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. If THERMAL POWER is greater than the P-6 setpoint but less than the P-10 setpoint, 2 hours is allowed to reduce THERMAL POWER below the P-6 setpoint or increase to THERMAL POWER above the P-10 setpoint. The NIS Intermediate Range Neutron Flux channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10. If THERMAL POWER is greater than the P-10 setpoint, the NIS power range detectors perform the monitoring and protection functions and the intermediate range is not required. The Completion Times allow for a slow and controlled power adjustment above P-10 or below P-6 and take into account the redundant capability afforded by the redundant OPERABLE channel, and the low probability of its failure during this period. This action does not require the inoperable channel to be tripped because the Function uses one-out-of-two logic. Tripping one channel would trip the reactor. Thus, the Required Actions specified in this Condition are only applicable when channel failure does not result in reactor trip.

(continued)

ACTIONS (continued)

G.1 and G.2

Condition G applies to two inoperable Intermediate Range Neutron Flux trip channels in MODE 2 when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint. Required Actions specified in this Condition are only applicable when channel failures do not result in reactor trip. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also reduce THERMAL POWER below the P-6 setpoint within two hours. Below P-6, the Source Range Neutron Flux channels will be able to monitor the core power level. The Completion Time of 2 hours will allow a slow and controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the NIS Intermediate Range Neutron Flux trip.

Required Action G.1 is modified by a note to indicate that normal plant control operations that individually add limited positive reactivity (i.e., temperature or boron concentration fluctuations associated with RCS inventory management or temperature control) are not precluded by this Action, provided SDM requirements in MODEs 1 and 2 with $K_{eff} \geq 1.0$ are maintained by observance of LCOs 3.1.4, 3.1.5, and 3.4.2.

H.1

Condition H applies to the Intermediate Range Neutron Flux trip when THERMAL POWER is below the P-6 setpoint and one or two channels are inoperable. Below the P-6 setpoint, the NIS source range performs the monitoring and protection functions. The inoperable NIS intermediate range channel(s) must be returned to OPERABLE status prior to increasing power above the P-6 setpoint. The NIS intermediate range channels must be OPERABLE when the power level is above the capability of the source range, P-6, and below the capability of the power range, P-10.

(continued)

ACTIONS (continued)

I.1

Condition I applies to one inoperable Source Range Neutron Flux trip channel when in MODE 2, below the P-6 setpoint. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the two channels inoperable, operations involving positive reactivity additions shall be suspended immediately.

This will preclude any power escalation. With only one source range channel OPERABLE, core protection is severely reduced and any actions that add positive reactivity to the core must be suspended immediately.

Required Action I.1 is modified by a note to indicate that normal plant control operations that individually add limited positive reactivity (i.e., temperature or boron concentration fluctuations associated with RCS inventory management or temperature control) are not precluded by this Action, provided SDM requirements in MODEs 1 and 2 with $K_{eff} \geq 1.0$ are maintained by observance of LCOs 3.1.4, 3.1.5, and 3.4.2.

J.1

Condition J applies to two inoperable Source Range Neutron Flux trip channels when in MODE 2, below the P-6 setpoint, or in MODE 3, 4, or 5 with the RTBs closed. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With both source range channels inoperable, the RTBs must be opened immediately. With the RTBs open, the core is in a more stable condition and the unit enters Condition L.

K.1 and K.2

Condition K applies to one inoperable source range channel in MODE 3, 4, or 5 with the RTBs closed. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the source range channels inoperable, 48 hours is allowed to restore it to an OPERABLE status. If the channel cannot be returned to an OPERABLE status, 1 additional hour is allowed to open the RTBs. Once the RTBs are open, the core is in a more stable condition and the unit enters

(continued)

ACTIONS

K.1 and K.2 (continued)

Condition L. The allowance of 48 hours to restore the channel to OPERABLE status, and the additional hour to open the RTBs, are justified in Reference 8.

L.1, L.2, and L.3

Condition L applies when the required number of OPERABLE Source Range Neutron Flux channels is not met in MODE 3, 4, or 5 with the RTBs open. With the unit in this Condition, the NIS source range performs the monitoring and protection functions. With less than the required number of source range channels OPERABLE, operations involving positive reactivity additions shall be suspended immediately. In addition to suspension of positive reactivity additions, all valves that could add unborated water to the RCS must be closed within 1 hour as specified in LCO 3.9.2. The isolation of unborated water sources will preclude a boron dilution accident.

Also, the SDM must be verified within 1 hour and once every 12 hours thereafter as per SR 3.1.1.1, SDM verification. With no source range channels OPERABLE, core protection is severely reduced. Verifying the SDM within 1 hour allows sufficient time to perform the calculations and determine that the SDM requirements are met. The SDM must also be verified once per 12 hours thereafter to ensure that the core reactivity has not changed. Required Action L.1 precludes any positive reactivity additions; therefore, core reactivity should not be increasing, and a 12 hour Frequency is adequate. The Completion Times of within 1 hour and once per 12 hours are based on operating experience in performing the Required Actions and the knowledge that unit conditions will change slowly.

Required Action L.1 is modified by a note that permits plant temperature changes provided the temperature change is accounted for in the calculated SDM. Introduction of temperature changes, including temperature increases when a positive MTC exists, must be evaluated to ensure they do not result in a loss of required SDM.

(continued)

ACTIONS (continued)

M.1 and M.2

Condition M applies to the following reactor trip Functions:

- Pressurizer Pressure - Low;
- Pressurizer Water Level - High;
- Reactor Coolant Flow - Low (Two Loops);
- RCP Breaker Position (Two Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a reactor trip above the P-7 setpoint and below the P-8 setpoint. These Functions do not have to be OPERABLE below the P-7 setpoint because there are no loss of flow trips below the P-7 setpoint. The 6 hours allowed to place the channel in the tripped condition is justified in Reference 7. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time.

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition M.

N.1 and N.2

Condition N applies to the Reactor Coolant Flow - Low (Single Loop) reactor trip Function. With one channel inoperable, the inoperable channel must be placed in trip within 6 hours. If the channel cannot be restored to OPERABLE status or the channel placed in trip within the 6 hours, then THERMAL POWER must be reduced below the P-8 setpoint within the next 4 hours. This places the unit in

(continued)

ACTIONS

N.1 and N.2 (continued)

a MODE where the LCO is no longer applicable. This trip Function does not have to be OPERABLE below the P-8 setpoint because other RPS trip Functions provide core protection below the P-8 setpoint. The 6 hours allowed to restore the channel to OPERABLE status or place in trip and the 4 additional hours allowed to reduce THERMAL POWER to below the P-8 setpoint are justified in Reference 7.

O.1 and O.2

Condition O applies to the RCP Breaker Position (Single Loop) reactor trip Function. There is one breaker position device per RCP breaker. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 6 hours. If the channel cannot be restored to OPERABLE status within the 6 hours, then THERMAL POWER must be reduced below the P-8 setpoint within the next 4 hours. This places the unit in a MODE where the LCO is no longer applicable. This Function does not have to be OPERABLE below the P-8 setpoint because other RPS Functions provide core protection below the P-8 setpoint. The 6 hours allowed to restore the channel to OPERABLE status and the 4 additional hours allowed to reduce THERMAL POWER to below the P-8 setpoint are justified in Reference 7.

P.1 and P.2

Condition P applies to Turbine Trip on Low Auto-Stop Oil Pressure or on Turbine Stop Valve Closure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 6 hours. If placed in the tripped condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-8 setpoint within the next 4 hours. The 6 hours allowed to place the inoperable channel in the tripped condition and the 4 hours allowed for reducing power are justified in Reference 7.

(continued)

ACTIONS
(continued)

Q.1 and Q.2

Condition Q applies to the SI Input from ESFAS reactor trip and the RPS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RPS for these Functions. With one train inoperable, 6 hours are allowed to restore the train to OPERABLE status (Required Action Q.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 6 hours (Required Action Q.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The Completion Time of 6 hours (Required Action Q.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows bypassing one train up to 12 hours for maintenance or surveillance testing, provided the other train is OPERABLE.

R.1 and R.2

Condition R applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RPS for the RTBs. With one train inoperable, 1 hour is allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RPS function. Placing the unit in MODE 3 removes the requirement for this particular Function.

The Required Actions have been modified by a Note which allows one channel to be bypassed for up to 12 hours for maintenance or surveillance testing, provided the other channel is OPERABLE.

(continued)

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ACTIONS
(continued)

S.1 and S.2

Condition S applies to the P-6 and P-10 interlocks. With one channel inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 3 within the next 6 hours. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RPS Function.

T.1 and T.2

Condition T applies to the P-7, P-8, and Turbine Impulse Pressure inputs. With one channel inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 2 within the next 6 hours. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging unit systems.

U.1, U.2.1, and U.2.2

Condition U applies to the RTB Undervoltage and Shunt Trip Mechanisms, or diverse trip features, in MODES 1 and 2. With one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours or the unit must be placed in a MODE where the requirement does not apply. This is accomplished by placing the unit in MODE 3 within the next 6 hours (54 hours total time)

(continued)

ACTIONS

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

followed by opening the RTBs in 1 additional hour (55 hours total time). The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. With the RTBs open and the unit in MODE 3, this trip Function is no longer required to be OPERABLE. The affected RTB should not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance to one of the diverse features. The allowable time for performing maintenance or surveillance testing the diverse features is 12 hours for the reasons stated under Condition R.

The Completion Time of 48 hours for Required Action U.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

V.1

With two RPS trains inoperable, no automatic capability is available to shut down the reactor, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

The SRs for each RPS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A Note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RPS Functions.

Note that each channel of process protection supplies both trains of the RPS. When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

(continued)

SR 3.3.1.1

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

Deviation criteria are determined by the unit staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the NIS channel output. If the calorimetric exceeds the NIS channel output by > 2% RTP, the NIS is not declared inoperable, but must be adjusted. If the NIS channel output cannot be properly adjusted, the channel is declared inoperable.

Two Notes modify SR 3.3.1.2. The first Note indicates that the NIS channel output shall be adjusted consistent with the calorimetric results if the absolute difference between the NIS channel output and the calorimetric is > 2% RTP. The second Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 12

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

hours are allowed for performing the first Surveillance after reaching 15% RTP. At lower power levels, calorimetric data are inaccurate.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted.

If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature and overpower ΔT Functions.

Two Notes modify SR 3.3.1.3. Note 1 indicates that the excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%. Note 2 clarifies that the Surveillance is required only if reactor power is ≥ 15% RTP and that 36 hours is allowed for performing the first Surveillance after reaching 15% RTP.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT. This test shall verify OPERABILITY by actuation of the end devices.

The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. Independent verification of RTB undervoltage and shunt trip Function is not required for the bypass breakers. No capability is provided for performing such a test at power. The independent test for bypass breakers is included in SR 3.3.1.14. The bypass breaker test shall include a local shunt trip. A Note has been added to indicate that this test must be performed on the bypass breaker prior to placing it in service.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The RPS is tested. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. All possible logic combinations, with and without applicable permissives, are tested for each protection function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

A note is added to SR 3.3.1.5 stating that the SR is not required to be performed for the source range neutron flux detector channels prior to entry into MODE 3 from MODE 2 until 4 hours after entry into MODE 3. This Note allows normal shutdown to proceed without delay for testing in MODE 2 and in MODE 3 until the RTBs are open and SR 3.3.1.5 is no longer required to be performed (i.e., the 4 hour delay allows a normal shutdown to be completed without a required hold on power reduction to perform the testing required by this SR). If the unit is in MODE 3 with the RTBs closed for greater than 4 hours, this SR must be performed prior to 4 hours after entry into MODE 3.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature and overpower ΔT Functions.

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is ≥ 50% RTP and that 24 hours is allowed for performing the first surveillance after reaching 50% RTP.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function.

Setpoints must be within the Allowable Values specified in Table 3.3.1-1.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology (Ref. 8). The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology (Ref. 8).

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of Reference 7.

SR 3.3.1.7 is modified by a Note that provides a 4 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed (i.e., the 4 hour delay allows a normal shutdown to be completed without a required hold on power reduction to perform the testing required by this SR). In addition, performing the COT of the source range instrumentation prior to entry into MODE 3 from MODE 2 may increase the probability of a reactor trip. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, except it is modified by a Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit condition. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within the Frequency specified in the Surveillance Frequency Control Program prior to reactor startup and four hours after reducing power below P-10 and P-6. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the source, intermediate and power range low instrument channels. The Frequency of "4 hours after reducing power below P-10" (applicable to intermediate and power range low channels) and "4 hours after reducing power below P-6" (applicable to source range channels) allows a normal shutdown to be completed and the unit removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance. The Frequency applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup and four hours after reducing power below P-10 or P-6. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 or < P-6 for more than 4 hours, then the

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

testing required by this surveillance must be performed prior to the expiration of the 4 hour limit. Four hours is a reasonable time to complete the required testing or place the unit in a MODE where this surveillance is no longer required. This test ensures that the NIS source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10 or < P-6) for periods > 4 hours. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.9

SR 3.3.1.9 is the performance of a TADOT and the Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. Since this SR applies to RCP undervoltage and underfrequency relays, setpoint verification requires elaborate bench calibration and is accomplished during the CHANNEL CALIBRATION.

SR 3.3.1.10

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

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology (Ref. 8). The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology (Ref. 8).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

SR 3.3.1.10 is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable. This Note applies to those Functions equipped with electronic dynamic compensation. Not all Functions to which SR 3.3.1.10 is applicable are equipped with electronic dynamic compensation.

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the power range neutron detectors consists of a normalization of the detectors based on a power calorimetric and flux map performed above 15% RTP. The CHANNEL CALIBRATION for the source range and intermediate range neutron detectors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. This Surveillance is not required for the NIS power range detectors for entry into MODE 2 or 1, and is not required for the NIS intermediate range detectors for entry into MODE 2, because the unit must be in at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.12

SR 3.3.1.12 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10. For Table 3.3.1-1 Functions 5 and 6, the CHANNEL CALIBRATION shall include a narrow range RTD cross calibration. This SR is modified by a Note stating that this test shall include verification of the electronic dynamic compensation time constants and the RTD response time constants. The RCS

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.1.12 (continued)

narrow range temperature sensors response time shall be ≤ a 4.0 second lag time constant.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.13

SR 3.3.1.13 is the performance of a COT of RPS interlocks.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of the Manual Reactor Trip, RCP Breaker Position, and the SI Input from ESFAS and the P-7 interlock. The test shall independently verify the OPERABILITY of the undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers and the undervoltage trip mechanism for the Reactor Trip Bypass Breakers.

The test shall also independently verify the OPERABILITY of the low power reactor trip block from the Power Range Neutron Flux (P-10) interlock and turbine first stage pressure. The TADOT verifies that when either the Turbine Impulse Pressure inputs or the Power Range Neutron Flux (P-10) interlock engage, reactor trips that are blocked by P-7 are enabled.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.14 (continued)

The SR is modified by a Note that excludes verification of setpoints from the TADOT. The Functions affected have no setpoints associated with them.

SR 3.3.1.15

SR 3.3.1.15 is the performance of a TADOT of Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4, except that this test is performed prior to reactor startup. A Note states that this Surveillance is not required if it has been performed within the previous 31 days. Verification of the Trip Setpoint does not have to be performed for this Surveillance. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to taking the reactor critical. This test cannot be performed with the reactor at power and must therefore be performed prior to reactor startup.

REFERENCES

1. UFSAR, Chapter 7.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.
4. UFSAR, Section 3.1.
5. IEEE-279-1968.
6. 10 CFR 50.49.
7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
8. EGR-NGGC-0153, "Engineering Instrument Setpoints."

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

The ESFAS instrumentation is segmented into three distinct but interconnected modules as identified below:

- Field transmitters or process sensors and instrumentation: provide a measurable electronic signal based on the physical characteristics of the parameter being measured;

- Signal processing equipment including analog protection system, field contacts, and protection channel sets: provide signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications; and

- ESFAS automatic initiation relay logic: initiates the proper unit shutdown or engineered safety feature (ESF) actuation in accordance with the defined logic and based on the bistable outputs from the signal process control and protection system.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as three, field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the ESFAS are shared with the Reactor Protection System (RPS). In some cases, the same channels also provide control system inputs. To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in

(continued)

BASES

BACKGROUND

Field Transmitters or Sensors (continued)

the Nominal Trip Setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria.

Signal Processing Equipment

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. These setpoints are defined in UFSAR, Chapter 6 (Ref. 1), Chapter 7 (Ref. 2), and Chapter 15 (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the ESFAS automatic initiation logic. Channel separation is maintained up to and through the input to the ESFAS automatic initiation logic.

The ESFAS automatic initiation instrumentation is designed in accordance with HBRSEP design criteria, which is described in UFSAR Section 3.1 (Ref. 4), and IEEE-279-1968 (Ref. 5).

Where a plant condition that requires protective action can be brought on by a failure or malfunction of the control system, and the same failure or malfunction prevents proper action of a protection system channel or channels designed to protect against the resultant unsafe condition, the remaining portions of the protection system will automatically initiate appropriate protective action whenever a plant condition monitored by the system reaches its trip setpoint. No single failure within the protection system will prevent proper protection system action when required. These requirements are described in Reference 5.

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BACKGROUND (continued)

Trip Setpoints and Allowable Values

The Nominal Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted (in accordance with the Nominal Trip Setpoint) when the "as left" value is within the established calibration tolerance band. A channel is required to be adjusted, if the actual Trip Setpoint is found outside the "as found" calibration tolerance band, such that the actual Trip Setpoint is within the "as left" calibration tolerance band.

The Nominal Trip Setpoints used in the bistables are based on the analytical limits stated in Reference 2. The selection of these Nominal Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays accounted for in setpoint calculations and accident analyses are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 6), the Nominal Trip Setpoints and Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Nominal Trip Setpoints, including their explicit uncertainties, is provided in the company setpoint methodology procedure (Ref. 9). The actual Nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. As noted in Table 3.3.2-1 (Note 1), a channel is considered OPERABLE with an actual Trip Setpoint value found outside its "as found" calibration tolerance band provided the Trip Setpoint value is conservative with respect to its Allowable Value and the Channel is re-adjusted to within the "as left" calibration tolerance band of the Nominal Trip Setpoint.

Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed.

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Value (continued)

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of calculations performed in accordance with the company setpoint methodology procedure (Ref. 9). Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section.

The Nominal Trip setpoints and Allowable Values listed in Table 3.3.2-1 are based on the methodology described in the company setpoint methodology procedure (Ref. 9), which incorporates all of the applicable uncertainties for each channel. The magnitudes of these uncertainties are factored into the determination of each Nominal Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

ESFAS Automatic Initiation Logic

The ESFAS relay logic equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of logic, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide ESF actuation for the unit. Each train is packaged in cabinets for physical and electrical separation to satisfy separation and independence requirements.

The ESFAS relay logic performs the decision logic for most ESF equipment actuation: generates the electrical output signals that initiate the required actuation: and provides the status, permissive, and annunciator output signals to the main control room of the unit.

The bistable outputs from the signal processing equipment are sensed by the relay logic and combined into logic matrices that represent combinations indicative of various transients. If a required logic matrix combination is

(continued)

BASES

BACKGROUND

ESFAS Automatic Initiation Logic (continued)

completed, the system will send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

The actuation of ESF components is accomplished through master and slave relays. The ESFAS relay logic energizes the master relays appropriate for the condition of the unit. Each master relay then energizes one or more slave relays, which then cause actuation of the end devices. The master relays are routinely tested for continuity after performance of the ACTUATION LOGIC TEST. Each master and slave relay is tested at a Frequency of 24 months by initiation of the Function.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer Pressure - Low is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

The LCO requires all instrumentation performing an ESFAS Function to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO generally requires OPERABILITY of two or three channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three configurations allow one channel to be tripped during maintenance or testing without causing an ESFAS initiation. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS.

The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents. ESFAS protection functions are as follows:

1. <u>Safety Injection</u>

Safety Injection (SI) provides two primary functions:

1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F): and

2. Boration to ensure recovery and maintenance of SDM (keff < 1.0).

These functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The SI signal is also used to initiate other Functions such as:

- Phase A Isolation;
- Containment Ventilation Isolation;
- Reactor Trip;
- Feedwater Isolation;
- Start of motor driven auxiliary feedwater (AFW) pumps; and
- Control room ventilation pressurization mode activation.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

1. Safety Injection (continued)

These other functions ensure:

- Isolation of nonessential systems through containment penetrations;
- Trip of the reactor to limit power generation;
- Isolation of main feedwater (MFW) to limit secondary side mass losses;
- Start of AFW to ensure secondary side cooling capability; and
- Activation of the control room filtration system to ensure habitability.

a. Safety Injection - Manual Initiation

The LCO requires one channel per train to be OPERABLE. The operator can initiate SI at any time by using either of two pushbuttons in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO for the Manual Initiation Function ensures the proper amount of redundancy is maintained in the manual ESFAS actuation circuitry to ensure the operator has manual ESFAS initiation capability.

Each channel consists of one push button and the interconnecting wiring to the actuation logic cabinet. Each push button actuates both trains. This configuration does not allow testing at power.

b. Safety Injection - Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed within the actuation subsystems, including the

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

b. Safety Injection - Automatic Actuation Logic and Actuation Relays (continued)

initiating relay contacts responsible for actuating the ESF equipment.

Manual and automatic initiation of SI must be OPERABLE in MODES 1, 2, 3, and 4 as indicated in Table 3.3.2-1. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. Because of the large number of components actuated on a SI, actuation is simplified by the use of the manual actuation push buttons. In addition, the Containment Pressure - High Function is required to be OPERABLE in MODE 4 since there may be sufficient energy in the primary or secondary systems to pressurize the containment following a pipe break. Therefore, automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support OPERABILITY of the Manual Initiation and Containment Pressure - High Functions.

These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Unit pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

c. Safety Injection - Containment Pressure - High

This signal provides protection against the following accidents:

- SLB inside containment;
- LOCA; and
- Feed line break inside containment.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

c. Safety Injection - Containment Pressure - High (continued)

Containment Pressure - High provides no input to any control functions. The transmitters (d/p cells) and electronics are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment.

Thus, the high pressure Function will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

Containment Pressure - High must be OPERABLE in MODES 1, 2, 3, and 4 when there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 5, and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment.

d. Safety Injection - Pressurizer Pressure - Low This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) relief or safety valve:
- SLB;
- A spectrum of rod cluster control assembly ejection accidents (rod ejection);
- Inadvertent opening of a pressurizer relief or safety valve;
- LOCAs; and
- SG Tube Rupture.

Three channels of pressurizer pressure provide input into the ESFAS actuation logic. These

(continued)

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

d. Safety Injection - Pressurizer Pressure - Low (continued)

channels initiate the ESFAS automatically when two of the three channels exceed the low pressure setpoint. These protection channels do not provide control functions: therefore the two-out-of-three logic is adequate to provide the required protection.

The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment, rod ejection). Therefore, the Trip Setpoint from which the Allowable Value is derived reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 (above 2000 psig) to mitigate the consequences of an HELB inside containment. This signal may be manually blocked by the operator below the 2000 psig setpoint. Automatic SI actuation below this pressure setpoint is then performed by the Containment Pressure - High signal.

This Function is not required to be OPERABLE in MODE 3 below the 2000 psig setpoint. Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. Steam Line - High Differential Pressure Between Steam Header and Steam Lines

Steam Line - High Differential Pressure provides protection against the following accidents:

- SLB upstream of MSL check valves;
- Feed line break; and

(continued)

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

e. Steam Line - High Differential Pressure Lines Between Steam Header and Steam (continued)

- Inadvertent opening of an SG relief or an SG safety valve.

With the transmitters located away from the main steam headers, it is not possible for them to experience adverse environmental conditions during an SLB event. Therefore, the Trip Setpoint from which the Allowable Value is calculated reflects only steady state instrument uncertainties. Steam line high differential pressure must be OPERABLE in MODES 1, 2, and 3 for RCS pressure ≥ 2000 psig when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). This Function is not required to be OPERABLE in MODE 3 with RCS pressure < 2000 psig, 4, 5, or 6 because there is not sufficient energy in the secondary side of the unit to cause an accident.

f, g. Safety Injection - High Steam Flow in Two Steam Lines Coincident With T_{avg} - Low or Coincident With Steam Line Pressure - Low

These Functions (1.f and 1.g) provide protection against the SLB accident.

Two steam line flow channels per steam line are required OPERABLE for these Functions. The steam line flow channels are combined in a one-out-of-two logic to indicate high steam flow in one steam line. The steam flow transmitters provide control inputs, but the control function cannot cause the events that the Function must protect against. Therefore, two channels are sufficient to satisfy redundancy requirements. The one-out-of-two configuration allows online testing because trip of one high steam flow channel is not sufficient to cause initiation. High steam flow in two steam lines is acceptable in the case of a single steam line fault due to the fact that the remaining intact steam lines

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

f, g. Safety Injection - High Steam Flow in Two Steam Lines Coincident With T_{avg} - Low or Coincident With Steam Line Pressure - Low

will pick up the full turbine load. The increased steam flow in the remaining intact lines will actuate the required second high steam flow trip. Additional protection is provided by Function 1.e, High Differential Pressure Between Steam Header and Steam Lines.

One channel of T_{avg} per loop and one channel of low steam line pressure per steam line are required OPERABLE. For each parameter, the channels for all loops or steam lines are combined in a logic such that two channels tripped will cause a trip for the parameter. For example, the low steam line pressure channels are combined in two-out-of-three logic. Thus, the Function trips on one-out-of-two high flow in any two-out-of-three steam lines if there is a low T_{avg} trip in any two-out-of-three RCS loops, or if there is a low pressure trip in any two-out-of-three steam lines. Since the accident that this Function protects against cause both low steam line pressure and low T_{avg} provision of one channel per loop or steam line ensures no single random failure can disable both of these Functions. The steam line pressure and T_{avg} channels provide control inputs, but the control function cannot initiate events that the Function acts to mitigate.

This Function must be OPERABLE in MODE 1, and MODES 2 and 3 above T_{ave} - Low interlock setpoint when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). This signal may be manually blocked by the operator when below the low T_{avg} setpoint. Above 543ºF, this Function is automatically unblocked. This Function is not required OPERABLE below 543ºF, because the reactor is not critical. SLB may be addressed by Containment Pressure High (inside containment) or by High Steam Flow in Two Steam Lines coincident with Steam Line Pressure - Low, for Steam Line

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

f, g. Safety Injection - High Steam Flow in Two Steam Lines Coincident With T_{avg} - Low or Coincident With Steam Line Pressure - Low (continued)

Isolation, followed by High Differential Pressure Between the Steam Header and One Steam Line, for SI. This Function is not required to be OPERABLE in MODE3 (with TAVG < 543ºF), 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to cause an accident.

The high steam line flow setpoint is set at the nominal trip setpoints defined in the linear function of turbine load steam pressure that is described in Note (d) to Table 3.3.2-1. The Allowable Values for the setpoint are defined in the linear function of turbine load steam pressure that is described in Note (c) to Table 3.3.2-1. The Nominal Trip Setpoint values are not given above 100% Rated Thermal Power (RTP) since operation is not allowed above 100% RTP. Allowable Values are specified as limited to the 100% RTP Allowable Value for the setpoint consistent with the plant design and Note (1) to Table 3.3.2-1.

2. Containment Spray

Containment Spray provides three primary functions:

1. Lowers containment pressure and temperature after an HELB in containment;

2. Reduces the amount of radioactive iodine in the containment atmosphere; and

3. Adjusts the pH of the water in the containment recirculation sump after a large break LOCA.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure;

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

2. Containment Spray

- Limit the release of radioactive iodine to the environment in the event of a failure of the containment structure; and

- Minimize corrosion of the components and systems inside containment following a LOCA.

The containment spray actuation signal starts the containment spray pumps and aligns the discharge of the pumps to the containment spray nozzle headers in the upper levels of containment. Water is initially drawn from the RWST by the containment spray pumps and mixed with a sodium hydroxide solution from the spray additive tank. When the RWST reaches the low low level setpoint, the spray pump suctions are shifted to the containment sump (through the RHR system) if

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

2. Containment Spray

continued containment spray is required. Containment spray is actuated automatically by Containment Pressure - High High.

a. Containment Spray - Manual Initiation

The operator can initiate containment spray at any time from the control room by simultaneously depressing two containment spray actuation pushbuttons. Because an inadvertent actuation of containment spray could have such serious consequences, two pushbuttons must be depressed simultaneously to initiate containment spray. Two Manual Initiation pushbuttons are required to be OPERABLE to ensure no single failure disables the Manual Initiation Function. Note that Manual Initiation of containment spray also actuates Phase B containment isolation and containment ventilation isolation.

b. Containment Spray - Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of containment spray must be OPERABLE in MODES 1, 2, 3, and 4 when there is a potential for an accident to occur, and sufficient energy in the primary or secondary systems to pose a threat to containment integrity due to overpressure conditions. In MODES 5 and 6, there is insufficient energy in the primary and secondary systems to result in containment overpressure. In MODES 5 and 6, there is also adequate time for the operators to evaluate unit conditions and respond, to mitigate the consequences of abnormal conditions by manually starting individual components.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

c. Containment Spray - Containment Pressure Hi - Hi

This signal provides protection against a LOCA or an SLB inside containment. The transmitters (d/p cells) are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

This is the only Function that requires the bistable output to energize to perform its required action. It is not desirable to have a loss of power actuate containment spray, since the consequences of an inadvertent actuation of containment spray could be serious. Therefore, two-out-of-three logic, on two sets of three (total of six channels), is used to generate the Containment Pressure-High High signal. One channel per set may be placed in trip and still maintain adequate margin to spurious spray actuation. Note that this Function has the requirement that no more than one channel per set is permitted to be placed in trip to decrease the probability of an inadvertent actuation.

Containment Pressure - High High must be OPERABLE in MODES3 1, 2, 3, and 4 when there is sufficient energy in the primary and secondary sides to pressurize the containment following a pipe break. In MODES 5, and 6, there is insufficient energy in the primary and secondary sides to pressurize the containment and reach the Containment Pressure - High High setpoints.

The Containment Pressure - High High Function also initiates a Main Steam Line Isolation signal, as described in Function 4.d.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

3. Containment Isolation (continued)

Containment Isolation provides isolation of the containment atmosphere, and all process systems that penetrate containment, from the environment. This Function is necessary to prevent or limit the release

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

3. Containment Isolation (continued)

of radioactivity to the environment in the event of a large break LOCA.

There are two separate Containment Isolation signals, Phase A and Phase B. Phase A isolation isolates all automatically isolable process lines, except component cooling water (CCW) and reactor coolant pump (RCP) seal water return, at a relatively low containment pressure indicative of primary or secondary system leaks. For these types of events, forced circulation cooling using the RCPs and SGs is the preferred (but not required) method of decay heat removal. Since CCW is required to support RCP operation, not isolating CCW on the low pressure Phase A signal enhances unit safety by allowing operators to use forced RCS circulation to cool the unit. Isolating CCW on the low pressure signal may force the use of feed and bleed cooling, which could prove more difficult to control.

Phase A containment isolation is actuated automatically by SI, or manually. All process lines penetrating containment, with the exception of CCW and RCP seal water return, are isolated. CCW is not isolated at this time to permit continued operation of the RCPs with cooling water flow to the thermal barrier heat exchangers or oil coolers. All process lines not equipped with remote operated isolation valves are manually closed, or otherwise isolated, prior to reaching MODE 4.

Manual Phase A Containment Isolation is accomplished by either of two switches in the control room. Either switch actuates both trains. Note that manual actuation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

The Phase B signal isolates CCW and RCP seal water return. This occurs at a relatively high containment pressure that is indicative of a large break LOCA or an SLB. For these events, forced circulation using the RCPs is no longer desirable. Both the CCW and RCP seal water return penetrations are classified as

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

3. Containment Isolation (continued)

essential penetrations in the UFSAR Section 6.2.4 (Ref. 7). The RCP seal water return valves are isolated after the associated RCP is shut down.

Phase B containment isolation is actuated by Containment Pressure - High High, or manually, as previously discussed. For containment pressure to reach a value high enough to actuate Containment Pressure - High High, a large break LOCA or SLB must have occurred. RCP operation will no longer be required and CCW to the RCPs is, therefore, no longer necessary. The RCPs can be operated with seal injection flow alone and without CCW flow to the thermal barrier heat exchanger.

Manual Phase B Containment Isolation is accomplished by the same pushbuttons that actuate Containment Spray. When the two pushbuttons are depressed simultaneously, Phase B Containment Isolation, Containment Ventilation Isolation, and Containment Spray will be actuated in both trains.

a. Containment Isolation - Phase A Isolation

(1) Phase A Isolation - Manual Initiation

Manual Phase A Containment Isolation is actuated by either of two switches in the control room. Either switch actuates both trains. Note that manual initiation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

(2) Phase A Isolation - Automatic Actuation Logic and Actuation Relays

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of Phase A Containment Isolation must be OPERABLE in MODES 1, 2, 3, and 4, when there is a potential

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

a. Containment Isolation - Phase A Isolation (continued)

for an accident to occur. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase A Containment Isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) Phase A Isolation-Safety Injection

Phase A Containment Isolation is also initiated by all Functions that initiate SI. The Phase A Containment Isolation requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

b. Containment Isolation - Phase B Isolation

Phase B Containment Isolation is accomplished by Manual Initiation, Automatic Actuation Logic and Actuation Relays, and by Containment Pressure channels (the same channels that actuate Containment Spray, Function 2). The Containment Pressure trip of Phase B Containment Isolation is energized to trip in order to minimize the potential of spurious trips that may damage the RCPs.

(1) Phase B Isolation - Manual Initiation

(2) Phase B Isolation - Automatic Actuation Logic and Actuation Relays

Manual and automatic initiation of Phase B containment isolation must be OPERABLE in MODES 1, 2, 3, and 4, when there is a potential for an accident to occur. In MODES 5 and 6, there is insufficient energy

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

b. Containment Isolation - Phase B Isolation (continued)

in the primary or secondary systems to pressurize the containment to require Phase B containment isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valve in response to abnormal or accident conditions.

(3) Phase B Isolation - Containment Pressure

The basis for containment pressure MODE applicability is as discussed for ESFAS Function 2.c above.

4. Steam Line Isolation

Isolation of the main steam lines provides protection in the event of an SLB inside or outside containment. Rapid isolation of the steam lines will limit the steam break accident to the blowdown from one SG, at most. For an SLB upstream of the main steam isolation valves (MSIVs), inside or outside of containment, closure of the MSIVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs terminates the accident as soon as the steam lines depressurize.

a. Steam Line Isolation - Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the control room. There are three pushbuttons in the control room, one for each steam line. Each pushbutton actuates both trains of Steam Line Isolation for its corresponding MSIV. The LCO requires one channel per line to be OPERABLE.

b. Steam Line Isolation - Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

(continued)

BASES

APPLICABLE SATETY ANALYSIS, LCO. and APPLICABILITY

b. Steam Line Isolation - Automatic Actuation Logic and Actuation Relays (continued)

Manual and automatic initiation of steam line isolation must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the RCS and SGs to have an SLB or other accident. This could result in the release of significant quantities of energy and cause a cooldown of the primary system. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs are closed. In MODES 4, 5, and 6, there is insufficient energy in the RCS and SGs to experience an SLB or other accident releasing significant quantities of energy.

c. Steam Line Isolation-Containment Pressure - High

This Function actuates closure of the MSIVs in the event of a LOCA or an SLB inside containment to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. Actuation logic is discussed under "Containment Spray-Containment Pressure," Function 2.c.

Containment Pressure - High High must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The Steam Line Isolation Function remains OPERABLE in MODES 2 and 3 unless all MSIVs are closed. In MODES 4, 5, and 6, there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure - High High setpoint.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

d, e. Steam Line Isolation - High Steam Flow in Two Steam Lines Coincident with T_{ave} - Low or Coincident With Steam Line Pressure - Low

These Functions (4.d and 4.e) provide closure of the MSIVs during an SLB or inadvertent opening of an SG relief or a safety valve, to maintain at least one unfaulted SG as a heat sink for the reactor and to limit the mass and energy release to containment.

These Functions were discussed previously as Functions 1.f. and 1.g.

These Functions must be OPERABLE in MODES 1 and 2, and in MODE 3, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines unless all MSIVs are closed. These Functions are not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

5. Feedwater Isolation

The primary function of the Feedwater Isolation signal is to stop the excessive flow of feedwater into the SGs. This Function is necessary to mitigate the effects of overfeeding the SGs, which could result in excessive cooldown of the primary system.

The Function is actuated on an SI signal and performs the following functions:

- Trips the MFW pumps; and
- Shuts the MFW isolation valves, MFW regulating valves and the bypass feedwater regulating valves.

This Function is actuated by an SI signal. The RPS initiates a turbine trip signal whenever a reactor trip is generated. In the event of SI, the unit and the turbine generator are tripped by the RPS. The MFW System is also taken out of operation and the AFW

(continued)

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

5. Feedwater Isolation (continued)

System is automatically started. The SI signal was discussed previously.

a. Feedwater Isolation - Automatic Actuation Logic and Actuation Relays

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Feedwater Isolation - Safety Injection

Feedwater Isolation is also initiated by all Functions that initiate SI. T he Feedwater Isolation Function requirements for these Functions are the same as the requirements for their SI -function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead Function 1, SI, is referenced for all initiating functions and requirements.

Feedwater Isolation Functions must be OPERABLE in MODES 1, 2, 3 and 4 (Mode 4 is SI Only) except when all MFIVs, MFRVs, and associated bypass valves are closed or isolated by a closed manual valve when the MFW System is in operation and the turbine generator may be in operation. In MODES 5 and 6, the MFW System and the turbine generator are not in service and this Function is not required to be OPERABLE.

6. Engineered Safety Feature Actuation System Interlocks

To allow some flexibility in unit operations, several interlocks are included as part of the ESFAS. These interlocks permit the operator to block some signals, automatically enable other signals, prevent some actions from occurring, and cause other actions to occur. The interlock Functions back up manual actions to ensure bypassable functions are in operation under the conditions assumed in the safety analyses.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY (continued)

a. Engineered Safety Feature Actuation System Interlocks - Pressurizer Pressure Low

This interlock permits a normal unit cooldown and depressurization without actuation of SI. With two-out-of-three pressurizer pressure channels (discussed previously) less than the interlock setpoint, the operator can manually block the Pressurizer Pressure - Low and the High Differential Pressure Between Steam Header and Steam Lines SI signal. When two-out-of-three pressurizer pressure channels exceed the interlock setpoint, these functions are automatically reinstated.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the unit without the actuation of SI or main steam isolation. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because system pressure must already be below the interlock setpoint for the requirements of the heatup and cooldown curves to be met.

b. Engineered Safety Feature Actuation System Interlocks - T_{avg} - Low

On increasing reactor coolant temperature, this interlock reinstates SI on High Steam Flow Coincident With Steam Line Pressure - Low or Coincident With T_{avg} - Low and provides an arming signal to the Steam Dump System. On decreasing reactor coolant temperature, the interlock allows the operator to manually block SI on High Steam Flow Coincident With Steam Line Pressure - Low or Coincident with T_{avg} - Low. On a decreasing temperature, the interlock also removes the arming signal to the Steam Dump System to prevent an excessive cooldown of the RCS due to a malfunctioning Steam Dump System.

Since T_{avg} is used as an indication of bulk RCS temperature, this Function meets redundancy requirements with one OPERABLE channel in each loop. These channels are used in two-out-of-three logic.

(continued)

APPLICABLE SAFETY ANALYSIS, LCO, and APPLICABILITY

b. Engineered Safety Feature Actuation System Interlocks - T_{avg} - Low (continued)

This Function must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to have an accident.

The ESFAS instrumentation satisfies Criterion 3 of the NRC Policy Statement.

ACTIONS

Note 1 has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.2-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument Loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified (e.g., on a per steam line, per loop, per SG, etc., basis), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

When the number of inoperable channels in a trip function exceed those specified in one or other related Conditions associated with a trip function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all ESFAS protection functions.

Condition A addresses the situation where one or more channels or trains for one or more Functions are inoperable

(continued)

BASES

ACTIONS

A.1 (continued)

at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1, B.2.1 and B.2.2

Condition B applies to manual initiation of:

- SI; and
- Phase A Isolation.

This action addresses the train orientation of the relay logic for the functions listed above. If a channel or train is inoperable, 48 hours is allowed to return it to an OPERABLE status. The specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each Function, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (54 hours total time) and in MODE 5 within an additional 30 hours (84 hours total time). The allowable Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.I, C.2.1 and C.2.2

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

- SI; and
- Containment Spray.

This action addresses the train orientation of the relay logic and the master and slave relays. Due to the plant

(continued)

BASES

ACTIONS

C.1. C.2.1 and C.2.2 (continued)

design, maintenance of a single channel can not be performed without causing all channels of the associated Function to be inoperable. In many cases, maintenance will also cause the associated train to be inoperable.

For repair or replacement of Engineered Safeguard System relays and/or test switches, 12 hours is a reasonable Completion Time for restoration of the two most frequently occurring types of failures that occur in the HBRSEP Unit No. 2 Engineered Safeguards System. These two failures are 1) failure of a logic or actuation relay, and 2) failure of the test switches used for the performance of the surveillance testing. A failure of either of these items only causes one portion of the Engineered Safeguards System to be inoperable, but due to the wiring configuration of the system (the common side of the relay power source is "daisy chained" together) the entire train must be considered inoperable once maintenance on the failed item has commenced.

The allowed time of 12 hours for inoperability of a single train on an ESFAS instrumentation train is considered to be acceptable based on the fact that the other ESFAS instrumentation train is available to perform the actuation function and the low probability of an event requiring an ESFAS actuation. In addition, the change provides the potential benefit of the avoidance of a plant shutdown transient by providing a time period to perform required surveillance testing or necessary maintenance prior to requiring a plant shutdown. If one train is inoperable, 12 hours are allowed to restore the train to OPERABLE status. The 12 hour Completion Time provides adequate time to perform maintenance or repairs to the automatic actuation logic and actuation relays. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (18 hours total time) and in MODE 5 within an additional 30 hours (48 hours total time). The Completion Times are reasonable, based on operating experience, to reach the required unit conditions

(continued)

BASES

ACTIONS

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

from full power conditions in an orderly manner and without challenging unit systems.

D.1, D.2.1, and D.2.2

Condition D applies to:

- Pressurizer Pressure - Low;
- Steam Line Differential Pressure - High;
- High Steam Flow in Two Steam Lines Coincident With T_{avg} - Low or Coincident With Steam Line Pressure - Low; and
- Steam Line Isolation Containment Pressure - High High.

If one channel is inoperable, 6 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic. Therefore, failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 6 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

The Action for Condition D is modified by a Note that allows a channel for Function 4.c, Steam Line Isolation – Containment Pressure – High High , to be taken out of the trip condition for 6 hours for maintenance purposes. The channel may be taken out of the trip condition multiple times provided the total time out of trip does not exceed 6 hours (not including the initial 6 hour action time). The Containment Pressure - High High channels are uniquely designed in that they are required to be

(continued)

ACTIONS

energized to be in the trip condition. Maintenance activities that interrupt power to the channel, such as, replacement of the comparator module, cause the channel to be taken out of the trip condition. Therefore, the note allows conducting these activities without being required to implement extraordinary measures to maintain the channel in the tripped condition. The 6-hour allowance is considered acceptable based on the low probability of an accident during this time, another channel of Containment Pressure - High High must fail to prevent the isolation of the steam line from Containment Pressure - High High, and other ESFAS functions provide an automatic steam line isolation function.

E.1, E.2.1, and E.2.2

Condition E applies to:

- Safety Injection Containment Pressure - High; and
- Containment Spray Containment Pressure -High High.

None of these signals has input to a control function. Thus, two-out-of-three logic is necessary to meet acceptable protective requirements. However, a two-out-of-three design would require tripping a failed channel. This is undesirable because a single failure would then cause spurious containment spray initiation. Spurious spray actuation is undesirable because of the cleanup problems presented. Therefore, these channels are designed with two-out-of-three on two sets of three logic. One channel per set may be placed in trip and still maintain adequate margin to spurious spray actuation.

To avoid the inadvertent actuation of containment spray and Phase B containment isolation, no more than one channel per set may be placed in trip. Restoring the channel to OPERABLE status, or placing the inoperable channel in trip within 6 hours, is sufficient to assure that the Function remains OPERABLE and minimizes the time that the Function may be in a partial trip condition (assuming the inoperable channel has failed high). The Completion Time is further justified based on the low probability of an event occurring during this interval. Failure to restore the inoperable channel to OPERABLE status, or place it in trip within 6 hours, requires the unit be placed in MODE 3 within the following 6 hours, MODE 4 within the next 6 hours, and MODE 5 within the next 24 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power

(continued)

ACTIONS

conditions in an orderly manner and without challenging unit systems. In MODE 5, these Functions are no longer required OPERABLE.

The Action for Condition E is modified by a Note that allows a channel for Function 2.c, Containment Spray - Containment Pressure - High High, and Function 3.b.(3), Containment Phase B Isolation - Containment Pressure - High High, to be taken out of the trip condition for 6 hours for maintenance purposes. The channel may be taken out of the trip condition multiple times provided the total time out of trip does not exceed 6 hours (not including the initial 6 hour action time). The Containment Pressure - High High channels are uniquely designed in that they are required to be energized to be in the trip condition. Maintenance activities that interrupt power to the channel, such as, replacement of the comparator module, cause the channel to be taken out of the trip condition. Therefore, the note allows conducting these activities without being required to implement extraordinary measures to maintain the channel in the tripped condition. The 6-hour allowance is considered acceptable based on the low probability of an accident during this time, another channel of Containment Pressure - High High must fail to prevent the initiation of containment spray or containment Phase B isolation from Containment Pressure - High High, and containment spray or containment Phase B isolation can be initiated manually.

<u>F.1, F.2.1, and F.2.2</u>

Condition F applies to:

- Manual Initiation of Steam Line Isolation.

For the Manual Initiation Function, this action addresses the train orientation of the relay logic. If a train or channel is inoperable, 48 hours are allowed to return it to OPERABLE status. The specified Completion Time is

(continued)

ACTIONS

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

reasonable considering the nature of this Function, the available redundancy, and the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

G.l. G.2.1 and G.2.2

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation.

The action addresses the train orientation of the relay logic and the master and slave relays for these functions. Due to the plant design, maintenance of a single channel can not be performed without causing all channels of the associated Function to be inoperable. In many cases, maintenance will also cause the associated train to be inoperable.

For repair or replacement of Engineered Safeguard System relays and/or test switches, 12 hours is a reasonable Completion Time for restoration of the two most frequently occurring types of failures that occur in the HBRSEP Unit No. 2 Engineered Safeguards System. These two failures are 1) failure of a logic or actuation relay, and 2) failure of the test switches used for the performance of the surveillance testing. A failure of either of these items only causes one portion of the Engineered Safeguards System to be inoperable, but due to the wiring configuration of the system (the common side of the relay power source is "daisy chained" together) the entire train must be considered inoperable once maintenance on the failed item has commenced.

The allowed time of 12 hours for inoperability of a single train on an ESFAS instrumentation train is considered to be

(continued)

ACTIONS

G.l, G.2.1 and G.2. (continued)

acceptable based on the fact that the other ESFAS instrumentation train is available to perform the actuation function and the low probability of an event requiring an ESFAS actuation. In addition, the change provides the potential benefit of the avoidance of a plant shutdown transient by providing a time period to perform required surveillance testing or necessary maintenance prior to requiring a plant shutdown. If one train is inoperable, 12 hours are allowed to restore the train to OPERABLE status. The 12 hour Completion Time provides adequate time to perform maintenance or repairs to the automatic actuation logic and actuation relays. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

H.l, H.2.1 and H.2.2

Condition H applies to the Pressurizer Pressure - Low and Tavg - Low interlocks.

With one channel inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. This action manually accomplishes the function of the interlock.

Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the

(continued)

BASES

ACTIONS

H.1. H.2.1 and H.2.2 (continued)

next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of these interlocks.

1.1, 1.2.1, 1.2.2, and 12.3

Condition I applies to the manual initiation function of Containment Spray and Phase B Isolation.

This action addresses the train orientation of the relay logic for the function. With one or more of the Containment Spray Manual Initiation pushbuttons inoperable, there is no means available to manually initiate Containment Spray or Phase B Containment Isolation through the automatic actuation relays. The Manual Initiation is set up on two-out- of-two logic, with only two pushbuttons provided, and a single failure of either of the pushbuttons renders the entire Manual Initiation function inoperable. Therefore, if a channel or train is inoperable, it must be returned to OPERABLE status within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the channel is not returned to OPERABLE status within the 1 hour Completion Time, the unit must be placed in MODE 3 within the next 6 hours, in MODE 4 within the following 6 hours, and in MODE 5 within the following 24 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. Placing the unit in MODE 5 removes all requirements for OPERABILITY of this function.

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the column of Table 3.3.2-1.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

A Note (Note 1) has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

Note that each channel of process protection supplies both trains of the ESFAS. When testing channel I, train A and train B must be examined. Similarly, train A and train B must be examined when testing channel II, channel III, and channel IV (if applicable). The CHANNEL CALIBRATION and COTS are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

The Surveillances are also modified by Note 2 to indicate that when a channel is placed in an inoperable status solely for the performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the redundant ESFAS train is OPERABLE. Upon completion of the Surveillance or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and the Required Actions performed. If maintenance is to be subsequently performed as a result of a failed surveillance test, LCO 3.3.2 ACTIONS are applicable. Note 2 to the Surveillance Requirements is based on operating history which has shown that 6 hours is generally the time required to perform the channel surveillance with additional time to allow for short term plant changes or verification of any abnormal responses. This 6 hour testing allowance does not significantly reduce the probability that the ESFAS will initiate when necessary.

SR 3.3.2.1

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1 (continued)

instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and reliability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The ESF relay logic is tested every 31 days on a STAGGERED TEST BASIS. The train being tested is placed in the test condition. All possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is tested for continuity. This verifies that the logic modules are OPERABLE and that there is an intact voltage signal path to the master relay coils. The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.3

SR 3.3.2.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay. The master relay is actuated by either a manual or automatic initiation of the function being tested. Contact operation is verified either by a continuity check of the circuit containing the master relay or proper operation of the end device during the supported equipment simulated or actual automatic actuation test. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.4

SR 3.3.2.4 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel, with the exception of the transmitter sensing device, will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology (Ref. 9). The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology (Ref. 9).

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the surveillance interval extension analysis in WCAP-10271-P-A (Ref. 8) when applicable.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified either by a continuity check of the circuit containing the slave relay, or by verification of proper operation of the end device during supported equipment simulated or actual automatic actuation test. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.6

SR 3.3.2.6 is the performance of a TADOT. This test is a check of Manual Actuation Functions. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions. The manual initiation Functions have no associated setpoints.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a CHANNEL CALIBRATION.

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

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology (Ref. 9). The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 7.
3. UFSAR, Chapter 15.
4. UFSAR, Section 3.1.

(continued)

BASES

REFERENCES (continued)

5. IEEE-279-1968.

6. 10 CFR 50.49.

7. UFSAR, Section 6.2.4.

8. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

9. EGR-NGGC-0153, "Engineering Instrument Setpoints."

B 3.3 INSTRUMENTATION

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display unit variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Accidents (DBAs).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident.

The availability of accident monitoring instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. These essential instruments are identified by unit specific documents (Ref. 5) addressing the recommendations of Regulatory Guide 1.97 (Ref. 2) as required by Supplement 1 to NUREG-0737 (Ref. 3).

The instrument channels required to be OPERABLE by this LCO include two classes of parameters identified during unit specific implementation of Regulatory Guide 1.97 as Type A and Category 1 variables.

Type A variables are included in this LCO because they provide the primary information required for the control room operator to take specific manually controlled actions for which no automatic control is provided, and that are required for safety systems to accomplish their safety functions for DBAs.

Category 1 variables are the key variables deemed risk significant because they are needed to:

(continued)

BASES

BACKGROUND (continued)

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

- Provide information to the operators that will enable them to determine the likelihood of a gross breach of the barriers to radioactivity release; and

- Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat.

These key variables are identified by the HBRSEP Regulatory Guide 1.97 analyses (Ref. 5). These analyses identify the unit specific Type A and Category 1 variables and provide justification for deviating from the NRC proposed list of Category 1 variables.

This LCO also includes certain parameters associated with risk-significant scenarios or mitigating systems as modeled in the HBRSEP Probabilistic Safety Assessment (PSA). These instruments include Auxiliary Feedwater Flow, PORV Position (primary indication), PORV Block Valve Position (primary indication), and Pressurizer Safety Valve Position (primary indication).

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the operability of Regulatory Guide 1.97 Type A and Category 1 variables so that the control room operating staff can:

- Perform the diagnosis specified in the emergency operating procedures (these variables are restricted to preplanned actions for the primary success path of DBAs), e.g., loss of coolant accident (LOCA);

- Take the specified, pre-planned, manually controlled actions, for which no automatic control is provided, and that are required for safety systems to accomplish their safety function;

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Determine whether systems important to safety are performing their intended functions;
- Determine the likelihood of a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of the NRC Policy Statement. Category 1, non - Type A, instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, Category 1, non - Type A, variables are important for reducing public risk.

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, which provide information required by the control room operators to perform certain manual actions specified in the unit Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses Regulatory Guide 1.97 instruments that have been designated Category 1, non - Type A and selected Category 2 and 3 instruments.

The OPERABILITY of the PAM instrumentation ensures there is sufficient information available on selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with the recommendations of Reference 1.

LCO 3.3.3 requires two OPERABLE channels for most Functions. Two OPERABLE channels ensure no single failure prevents operators from getting the information necessary for them to determine the safety status of the unit, and to bring the unit to and maintain it in a safe condition following an accident. The exception to the single failure criterion is the RCS Cold Leg wide range instrumentation which for RCS Loops "B" and "C" is powered from the same instrument power

(continued)

BASES

LCO (continued)

supply. Furthermore, OPERABILITY of two channels allows a CHANNEL CHECK during the post accident phase to confirm the validity of displayed information.

The exception to the two channel requirement is Containment Isolation Valve (CIV) Position. In this case, the important information is the status of the containment penetrations. The LCO requires one position indicator for each active CIV. This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve and prior knowledge of a passive valve, or via system boundary status. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

Type A and Category 1 variables are required to meet Regulatory Guide 1.97 Category 1 (Ref. 2) design and qualification requirements for seismic and environmental qualification, single failure criterion, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display.

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1.

1, 2. Power Range and Source Range Neutron Flux

Power Range and Source Range Neutron Flux indication is provided to verify reactor shutdown. The two ranges are necessary to cover the full range of flux that may occur post accident.

Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

3, 4. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures

RCS Hot Leg Temperatures are Category 1 variables provided for verification of core cooling and long term surveillance. The RCS Cold Leg Temperatures are

(continued)

BASES

LCO

3, 4. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures (continued)

Category 1 in RCS Loop "B" and "C" and Category 3 in RCS Loop "A."

RCS hot leg temperatures are used to determine RCS subcooling margin. RCS subcooling margin will allow termination of safety injection (SI), if still in progress, or reinitiation of SI if it has been stopped. RCS subcooling margin is also used for unit stabilization and cooldown control. The RCS Cold Leg temperatures provide backup/verification indication to the core exit temperature.

In addition, RCS cold leg temperature is used in conjunction with RCS hot leg temperature to verify the unit conditions necessary to establish natural circulation in the RCS. The RCS Loop "A" Cold Leg temperature instrument is a Category 3 variable and does not meet Regulatory Guide 1.97 design criteria for emergency power. RCS Loops "B" and "C" Cold Leg temperature instruments do not meet Regulatory Guide 1.97 design criteria for power redundancy.

5. Reactor Coolant System Pressure (Wide Range)

RCS wide range pressure from the Inadequate Core Cooling Monitor is a Category 1 variable provided for verification of core cooling and RCS integrity long term surveillance.

RCS pressure is used to verify delivery of SI flow to RCS from at least one train when the RCS pressure is below the pump shutoff head. RCS pressure is also used to verify closure of manually closed spray line valves and pressurizer power operated relief valves (PORVs).

In addition to these verifications, RCS pressure is used for determining RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. RCS pressure can also be used:

(continued)

BASES

LCO

5. Reactor Coolant System Pressure (Wide Range) (continued)

- to determine whether to terminate actuated SI or to reinitiate stopped SI;
- to determine when to reset SI and shut off low head SI;
- to manually restart low head SI;
- as reactor coolant pump (RCP) trip criteria; and

(continued)

BASES

LCO 5. Reactor Coolant System Pressure (Wide Range) (continued)

- to make a determination on the nature of the accident in progress and where to go next in the procedure.

RCS subcooling margin is also used for unit stabilization and cooldown control.

RCS pressure is also related to three decisions about depressurization. They are:

- to determine whether to proceed with primary system depressurization;
- to verify termination of depressurization; and
- to determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

A final use of RCS pressure is to determine whether to operate the pressurizer heaters.

RCS wide range pressure from the Inadequate Core Cooling Monitor is a Type A variable because the operator uses this indication to monitor the cooldown of the RCS following a steam generator tube rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting steam generator (SG) pressure or level, would use this indication. Furthermore, RCS pressure is one factor that may be used in decisions to terminate RCP operation.

LCO 6. Refueling Water Storage Tank Level

Refueling Water Storage Tank Level is provided as an indication of the availability of an adequate suction head for the RHR System following a loss of coolant accident (LOCA). This indication also provides the operator with information needed to determine when to manually initiate long term recirculation in the RCS. When the RWST level is compared with containment sump

(continued)

LCO

6. Refueling Water Storage Tank Level (continued)

level, RCS leakage outside containment can be assessed.

7. Containment Sump Water Level (Wide Range)

Containment Sump Water Level is provided for verification and long term surveillance of RCS integrity.

Containment Sump Water Level is used to determine:

- containment sump level accident diagnosis; and
- when to begin the recirculation procedure.

The function for sump level accident diagnosis is provided by the lowest range of each channel which provide early indication of a significant RCS leak.

The indication to determine when to begin the recirculation procedure is provided by the highest range of each channel to ensure an adequate level of water in the ECCS sump.

8. Containment Pressure (Wide Range)

Containment Pressure (Wide Range) is provided for verification of RCS and containment OPERABILITY.

Containment pressure is used to provide indication of whether the overall containment cooling function provided by containment spray and fan coolers is being achieved. Containment pressure is also used to verify the Containment Pressure-High SI signal and the Containment Pressure-High High Spray and Steam Line Isolation Signals.

9. Containment Isolation Valve Position

CIV Position is provided for verification of Containment OPERABILITY, and Phase A and Phase B isolation.

When used to verify Phase A and Phase B isolation, the important information is the isolation status of the containment penetrations. The LCO requires one channel of valve position indication to be

(continued)

BASES

LCO

9. Containment Isolation Valve Position (continued)

OPERABLE for each active CIV in a containment penetration flow path, i.e., two total channels of CIV position indication for a penetration flow path with two active valves. For containment penetrations with only one active CIV, Note (b) requires a single channel of valve position indication to be OPERABLE.

This is sufficient to redundantly verify the isolation status of each isolable penetration either via indicated status of the active valve, as applicable, and prior knowledge of a passive valve, or via system boundary status. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE. Note (a) to the Required Channels states that the Function is not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

10. Containment Area Radiation (High Range)

Containment Area Radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. Containment radiation level is used to determine the type of high energy line break (HELB) that has occurred inside containment.

11. Not Used

12. Pressurizer Level

Pressurizer Level is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer

(continued)

BASES

LCO

12. Pressurizer Level (continued)

water level is also used to verify the unit conditions necessary to establish natural circulation in the RCS and to verify that the unit is maintained in a safe shutdown condition.

13. Steam Generator Water Level (Narrow Range)

SG Water Level is provided to monitor operation of decay heat removal via the SGs. Redundant monitoring capability is provided by two channels per SG. The level signal is input to the unit computer, a control room indicator, SG water level control, and the RPS.

SG Water Level is used to:

- identify the faulted SG following a tube rupture;
- verify that the intact SGs are an adequate heat sink for the reactor; and
- determine the nature of the accident in progress (e.g., verify an SGTR).

14. Condensate Storage Tank (CST) Level

CST Level is provided to ensure water supply for auxiliary feedwater (AFW). CST Level is displayed in the control room.

CST Level is considered a Type A variable because the control room meter is considered the primary indication used by the operator.

The DBAs that require AFW are the loss of electric power, steam line break (SLB), and small break LOCA.

The CST is the initial source of water for the AFW System. However, as the CST is depleted, manual operator action is necessary to replenish the CST or align suction to the AFW pumps from the Service Water System.

(continued)

BASES

LCO (continued)

15, 16, 17, 18. Core Exit Temperature

Core Exit Temperature is provided for verification and long term surveillance of core cooling.

Adequate core cooling is ensured with two valid Core Exit Temperature channels per quadrant with one core exit thermocouple per required channel (Ref. 4). Core Exit Temperature is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Core Exit Temperature is also used for unit stabilization and cooldown control.

Two OPERABLE channels of Core Exit Temperature are required in each quadrant to provide indication of radial distribution of the coolant temperature rise across representative regions of the core. Power distribution symmetry was considered in determining the specific number and locations provided for diagnosis of local core problems. Two channels of Core Exit Temperature per quadrant ensures that a single failure will not disable the ability to determine the core exit temperature in any quadrant. The two channels, each with a minimum of one Core Exit Thermocouple per quadrant, must be powered from separate trains to satisfy the single failure requirement.

19. Auxiliary Feedwater Flow

AFW Flow is provided to monitor operation of decay heat removal via the SGs.

The three AFW discharge lines from the motor driven AFW pumps and the three AFW discharge lines from the steam driven AFW pump each contain one primary flow indicator. This provides two AFW flow paths per SG, for a total of six AFW lines and flow indicators. Since the primary indication used by the operator during an accident is the control room indicator, the PAM specification deals specifically with this portion of the instrument channel.

AFW flow is used three ways:

- to verify delivery of AFW flow to the SGs;
- to determine adequacy of the secondary heat sink; and

(continued)

BASES

LCO

19. Auxiliary Feedwater Flow (continued)

- to regulate AFW flow so that the SG tubes remain covered.

AFW flow is also used by the operator to verify that the AFW System is delivering the correct flow to each SG. However, the primary indication used by the operator to ensure an adequate inventory is SG level.

20. Steam Generator Pressure

Steam generator pressure is used to diagnose a faulted SG. SG pressure also provides information required to mitigate an SGTR event, verify natural circulation and to maintain the unit in a safe shutdown condition.

21. Containment Spray Additive Tank Level

Containment spray additive tank level is used to monitor the volume of sodium hydroxide addition to the containment spray for elemental iodine removal from the containment atmosphere following a LOCA. The contents of the spray additive tank (sodium hydroxide solution) are mixed into the spray stream to provide adequate iodine removal from the containment atmosphere by a washing action.

Direct Indication of Relief and Safety Valve Position

The consequence of a failure of relief and safety valves to close is a loss of coolant and depressurization of the RCS. A positive indication of the position of these valves can aid the operator in diagnosing a failure and in taking appropriate corrective action. Thus, the consequences of a failure of these valves can be reduced if the operator can reliably determine that a valve has failed to close.

22. PORV Position (Primary)

Each PORV is equipped with two stem mounted limit switches, which are seismically qualified and powered

(continued)

BASES

LCO

22. PORV Position (Primary) (continued)

from an emergency power source, to provide the direct (primary) means of valve position indication, from fully closed to fully open.

23. PORV Block Valve Position (Primary)

Each PORV block valve is equipped with a Limitorque operator and position indication which is seismically qualified and powered from an emergency power source, to provide the direct (primary) means of valve position indication.

24. Safety Valve Position (Primary)

Each pressurizer safety valve is equipped with a single acoustical position indication system, which is seismically qualified and powered from an emergency power source, to provide the direct (primary) means of valve position indication. This system alarms in the control room to indicate an open safety valve.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and pre-planned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function are tracked separately for each Function starting from the time the Condition was entered for that Function.

(continued)

BASES

ACTIONS (continued)

A.1

Condition A applies when one or more Functions have one required channel that is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channel (or in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval. Condition A is modified by a Note that excludes certain PAM Functions since each of these Functions has only one channel. Condition D provides appropriate Required Actions for PAM Functions that have only one channel with that channel inoperable.

B.1

Condition B applies when the Required Action and associated Completion Time for Condition A are not met. This Required Action specifies initiation of actions in Specification 5.6.6, which requires a written report to be submitted to the NRC immediately. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement since alternative actions are identified before loss of functional capability, and given the likelihood of unit conditions that would require information provided by this instrumentation.

(continued)

BASES

ACTIONS (continued)

C.1

Condition C applies when one or more Functions have two inoperable required channels (i.e., two channels inoperable in the same Function). Required Action C.1 requires restoring one channel in the Function(s) to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

D.1

Condition D applies when one or more Functions, which have single, non-redundant position indication channels, have one required channel inoperable. Required Action D.1 requires that channel be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with the required position indication channel inoperable is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of the inoperable channel limits the risk that the PAM Function will be in a degraded condition should an accident occur. Condition D is modified by a Note that excludes PAM Functions that have two or more required channels. Condition A provides appropriate Required Actions for PAM Functions that have two or more channels with one channel inoperable.

(continued)

BASES

ACTIONS (continued)

E.1

Condition E applies when the Required Action and associated Completion Time of Condition C or D are not met. Required Action E.1 requires entering the appropriate Condition referenced in Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition C or D, and the associated Completion Time has expired, Condition E is entered for that channel and provides for transfer to the appropriate subsequent Condition.

F.1 and F.2

If the Required Action and associated Completion Time of Conditions C or D are not met and Table 3.3.3-1 directs entry into Condition F, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 hours.

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

(continued)

BASES

ACTIONS (continued)

G.1

Condition H applies to the Containment Sump Water Level, Containment Pressure, Containment Area Radiation, Auxiliary Feedwater Flow, PORV Position, PORV Block Valve Position, and Safety Valve Position Functions, which have alternate monitoring means available for use. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means are used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.6, in the Administrative Controls section of the TS. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1; except Function 9, Containment Isolation Valve Position; Function 22, PORV Position (Primary); Function 23, PORV Block Valve Position (Primary); and Function 24, Safety Valve Position (Primary). SR 3.3.3.3 applies only to Functions 9, 22, 23, and 24.

SR 3.3.3.1

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.1 (continued)

should be compared to similar unit instruments located throughout the unit.

Channel deviation criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.3.2

CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter with the necessary range and accuracy. This SR is modified by a Note that excludes neutron detectors. The calibration method for neutron detectors is specified in the Bases of LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation." The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.3.3

SR 3.3.3.3 is the performance of a TADOT of containment isolation valve position indication, PORV position (primary) indication, PORV block valve position (primary) indication, and safety valve position (primary) indication. The test shall independently

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.3 (continued)

verify the OPERABILITY of position indication against the actual position of the associated valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. The affected Functions have no setpoints.

REFERENCES

1. NRC Safety Evaluation Report, H. B. Robinson Steam Electric Plant Unit No. 2, Docket No. 50-261, Conformance to Regulatory Guide 1.97, transmitted to CP&L by letter dated March 5, 1987.

2. Regulatory Guide 1.97, Revision 3, May 1983.

3. NUREG-0737, Supplement 1, "TMI Action Items."

4. CP&L Letter to NRC, "Inadequate Core Cooling Instrumentation, Generic Letter 82-28, NUREG-0737, Item II.F.2, Implementation Letter/License Amendment Request," dated September 16, 1987.

5. CP&L letters dated December 31, 1984, July 18, 1985, July 28, 1985, May 1, 1987, September 9, 1987, and September 14, 1999, regarding the HBRSEP Regulatory Guide 1.97 submittal.

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown System

BASES

BACKGROUND

The Remote Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AFW) System and the steam generator (SG) safety valves can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Reactor Coolant System (RCS) from outside the control room allows extended operation in MODE 3.

If the control room becomes inaccessible, the operators can establish local control, and place and maintain the unit in MODE 3. Controls and necessary transfer switches are located locally at the switchgear, motor control panels, or other local stations. The unit automatically reaches MODE 3 following a unit shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the remote shutdown control and instrumentation functions ensures there is sufficient information available on selected unit parameters to place and maintain the unit in MODE 3 should the control room become inaccessible.

APPLICABLE SAFETY ANALYSES

The Remote Shutdown System is required to provide equipment at appropriate locations outside the control room with a capability to promptly shut down and maintain the unit in a safe condition in MODE 3.

The Remote Shutdown System instrumentation is described in UFSAR Section 7.4.1 (Ref. 1).

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The Remote Shutdown System is considered an important contributor to the reduction of unit risk to accidents and as such it has been retained in the Technical Specifications as indicated in the NRC Policy Statement.

LCO

The Remote Shutdown System LCO provides the OPERABILITY requirements of the instrumentation and controls necessary to place and maintain the unit in MODE 3 from locations other than the control room. The instrumentation and controls typically required are listed in Bases Table B 3.3.4-1.

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

- Core reactivity control (initial and long term);
- RCS pressure control;
- Decay heat removal via the AFW System and the SG safety valves;
- RCS inventory control via charging flow; and
- Safety support systems for the above Functions, including service water and component cooling water.

A Function of a Remote Shutdown System is OPERABLE if all instrument and control channels needed to support the Remote Shutdown System Function are OPERABLE. In some cases, the required information or control capability is available from several alternate sources. In these cases, the Function is OPERABLE as long as one channel of any of the alternate information or control sources is OPERABLE.

The remote shutdown instrument and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure the instruments and control circuits will be OPERABLE if unit conditions require that the Remote Shutdown System be placed in operation.

(continued)

BASES

APPLICABILITY

The Remote Shutdown System LCO is applicable in MODES 1, 2, and 3. This is required so that the unit can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the unit is already subcritical and in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument control functions if control room instruments or controls become unavailable.

ACTIONS

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. Separate Condition entry is allowed for each Function listed on Table B 3.3.4-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function are tracked separately for each Function starting from the time the Condition was entered for that Function.

<u>A.1</u>

Condition A addresses the situation where one or more required Functions of the Remote Shutdown System are inoperable. This includes any Function listed in Table B 3.3.4-1, as well as the control and transfer switches.

Condition A is applicable when any combination of the control parameters and equipment controlled by listed control parameters are inoperable such that the required number is not met. Example: Condition A shall be entered in the situation where three Service Water pumps have inoperable remote shutdown controls and the fourth pump is inoperable for other reasons. In this case, the required number of functions of one (1) would not be met.

The Required Action is to restore the required Function to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the 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 4 within 12 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.

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1

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

Channel deviation criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If the channels are within the criteria, it is an indication that the channels are OPERABLE. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

As specified in the Surveillance, a CHANNEL CHECK is only required for those channels which are normally energized. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.2

SR 3.3.4.2 verifies each required Remote Shutdown System control circuit and transfer switch performs the intended function. This verification is performed from the remote shutdown panel and locally, as appropriate. Operation of the equipment from the remote shutdown panel is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the unit can be placed and maintained in MODE 3 from the remote shutdown panel and the local control stations. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.4.3

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.4.4

SR 3.3.4.4 is the performance of a TADOT. This test should verify the OPERABILITY of the reactor trip breakers (RTBs) open and closed indication on the remote shutdown panel, by actuating the RTBs. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 7.4.1.

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

FUNCTION/INSTRUMENT OR CONTROL PARAMETER	REQUIRED NUMBER OF FUNCTIONS
1. Reactivity Control	
a. Source Range Neutron Flux	1
b. Reactor Trip Breaker Position[(a)]	1 per trip breaker
c. Manual Reactor Trip[(a)]	1 per trip breaker
2. Reactor Coolant System (RCS) Pressure Control	
a. Pressurizer Pressure	1
b. Pressurizer Heater Controls	1
3. Decay Heat Removal via Steam Generators (SGs)	
a. RCS Hot Leg Temperature Wide Range Loop A	1
b. RCS Cold Leg Temperature Wide Range Loop A	1
c. Motor Driven AFW Pump Controls	1
d. SG Pressure	1 per SG
e. SG Level (Wide Range)	1 per SG
f. Condensate Storage Tank Level	1
4. RCS Inventory Control	
a. Pressurizer Level	1
b. Charging Pump Controls	1
c. Refuel Water Storage Tank Level	1
5. Support Functions	
a. Component Cooling Water Pump Controls	1
b. Service Water Pump Controls	1

(a) This function is local indication and manual trip feature at the breaker and applies to Reactor Trip Breakers and Reactor Trip Bypass Breakers that are racked in.

B 3.3 INSTRUMENTATION

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

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate an LOP start if a loss of voltage or degraded voltage condition occurs on the emergency bus. There are two LOP start signals for each 480 V emergency bus.

Undervoltage relays with definite time characteristics are provided on each 480 V emergency bus for detecting a sustained degraded voltage condition or a loss of bus voltage. The Loss of Voltage Function is provided by two relays on each bus. These relays are arranged in a one-out-of-two logic, such that either relay will generate an LOP signal if the voltage is below approximately 68% for a short time (loss of bus voltage). The Degraded Voltage Function is provided by three relays on each bus, which are combined in a two-out-of-three logic to generate an LOP signal if the voltage is below approximately 90% for a long period of time (degraded voltage). The LOP start actuation is described in UFSAR, Section 8.3 (Ref. 1).

Trip Setpoints and Allowable Values

The Trip Setpoints used in the relays are based on Degraded Grid Voltage Relay calculations (References 2 and 5). The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account.

Trip Setpoints and tolerances are specified for each Function in the LCO. If the measured setpoint falls within the tolerance band, the relay is considered OPERABLE. Operation with a measured setpoint less conservative than the Trip Setpoint, but within the tolerance band, is acceptable provided that operation and testing is consistent with the assumptions of the setpoint calculation. Each Trip Setpoint specified is more conservative than the analytical values determined in References 2 and 5 in order to account for instrument uncertainties appropriate to the trip function.

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

These uncertainties are defined in the company setpoint methodology procedure (Ref. 4).

The dropout time delay on the loss of voltage relays is very short, almost instantaneous. This short time delay is necessary to preclude damage to equipment from operating on less than minimum manufacturer's recommended voltage for continuous motor operation. The dropout time delay on the degraded voltage relays is significantly longer. A long time delay is desired such that it will minimize the effects of short duration disturbances on the grid. However, the allowable time duration of a degraded voltage condition must be short enough that it will not result in failure of safety systems or components.

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS).

Accident analyses credit the loading of the DG based on the loss of offsite power concurrent with a loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power. The analyses assume a non-mechanistic DG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions.

The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in UFSAR, Chapter 15 (Ref. 3), in which a loss of offsite power is assumed.

The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay, if applicable. The response times for ESFAS actuated equipment in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation,"

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

include the appropriate DG loading and sequencing delay.

The LOP DG start instrumentation channels satisfy Criterion 3 of the NRC Policy Statement.

LCO

The LCO for LOP DG start instrumentation requires that two channels per bus of loss of voltage and three channels per bus of degraded voltage Functions be OPERABLE in MODES 1, 2, 3, and 4 when the LOP DG start instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, these channels must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed. Loss of the LOP DG Start Instrumentation Function could result in the delay of safety systems initiation when required. This could lead to unacceptable consequences during accidents. For example, during the loss of offsite power the DG powers the motor driven auxiliary feedwater pumps. Failure of these pumps to start would leave only one turbine driven pump, as well as an increased potential for a loss of decay heat removal through the secondary system.

APPLICABILITY

The LOP DG Start Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE so that it can perform its function on an LOP or degraded power to the AC Instrument bus.

A Note has been added in the APPLICABILITY which permits blocking the Degraded Voltage Function when starting a reactor coolant pump. This is an exception which applies in all MODES except MODE 1, and is taken to avoid challenging the trip setpoints with the bus voltage dip normally experienced when a large electrical load is placed on the bus.

ACTIONS

In the event a channel is found inoperable, then the function that channel provides must be declared inoperable

(continued)

BASES

ACTIONS (continued)

and the LCO Condition entered for the particular protection function affected.

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in the LCO. The Completion Time(s) of the inoperable channel(s) of a Function are tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the LOP DG start Function with one or more loss of voltage channels per bus inoperable.

If one or more channels are inoperable, Required Action A.1 requires that channels be restored to OPERABLE status within one hour. With one or more Loss of Voltage Function channels inoperable, a loss of the required function may have occurred.

The 1 hour Completion Time allows for time to repair most failures and takes into account the low probability of an event requiring an LOP actuation during this interval.

B.1

Condition B applies to the LOP Degraded Voltage Function with one degraded voltage channel per bus inoperable.

If one of the three channels is inoperable, Required Action B.1 requires that channel to be placed in trip within 6 hours. With a channel in trip, the LOP DG start instrumentation channels are then configured to provide a one-out-of-two logic to initiate a trip of the incoming offsite power.

(continued)

BASES

ACTIONS

B.1 (continued)

The specified Completion Time and time allowed for tripping one channel are reasonable considering the Function remains fully OPERABLE on every bus and the low probability of an event occurring during these intervals.

C.1

Condition C applies when more than one degraded voltage channel on a single bus is inoperable.

Required Action C.1 requires restoring all but one channel on each bus to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

D.1

Condition D applies to each of the LOP DG start Functions when the Required Action and associated Completion Time for Condition A, B, or C are not met.

In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources - Operating," or LCO 3.8.2, "AC Sources - Shutdown," for the DG made inoperable by failure of the LOP DG start instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure unit safety.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1 (continued)

The SR is modified by a Note that excludes verification of the setpoint from the TADOT. Setpoint verification is accomplished during the CHANNEL CALIBRATION.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, should include a single point verification that the trip occurs within the required time delay, as shown in Reference 1.

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 8.3.
2. Calculation RNP-E-8.002, AC Auxiliary Electrical Distribution System Voltage/Load Flow/Fault Current Study
3. UFSAR, Chapter 15.
4. EGR-NGGC-0153, Engineering Instrument Setpoints
5. RNP-I/INST-1010, Emergency Bus – Degraded Grid Voltage Relay

B 3.3 INSTRUMENTATION

B 3.3.6 Containment Ventilation Isolation Instrumentation

BASES

BACKGROUND

Containment ventilation isolation instrumentation closes the containment isolation valves in the Pressure and Vacuum Relief System and the Purge System. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. The Pressure and Vacuum Relief System may be in use during reactor operation and the Purge System will normally be in use with the reactor shutdown.

Containment Ventilation isolation initiates on an automatic safety injection (SI) signal or by manual actuation of Containment Isolation Phase A. The Bases for LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," discuss these modes of initiation.

Two radiation monitoring channels provide actuation signals to containment ventilation isolation. The two channels, the R-11 particulate and the R-12 gaseous, monitor a continuous containment air sample, which is drawn from a single location through the R-11 and R-12 monitors in series and then returned to the containment. Both detectors will respond to most events that release radiation to containment. However, analyses have not been conducted to demonstrate that all credible events will be detected by more than one monitor. Therefore, for the purposes of this LCO the two channels are not considered redundant. Instead, they are treated as two one-out-of-one Functions. Since the purge exhaust monitors constitute a sampling system, various components such as sample line valves, sample pumps, and filter motors are required to support monitor OPERABILITY.

Each of the systems has inner and outer containment isolation valves in its supply and exhaust ducts. A high radiation signal from either of the two channels initiates containment ventilation isolation, which closes both inner and outer containment isolation valves in the Pressure and Vacuum Relief System and the Purge System. These systems are described in the Bases for LCO 3.6.3, "Containment Isolation Valves."

(continued)

BASES

APPLICABLE SAFETY ANALYSES

The containment ventilation isolation radiation monitors ensure closing of the ventilation isolation valves. They are the primary means for automatically isolating containment in the event of a fuel handling accident during shutdown. Containment isolation in turn ensures meeting the containment leakage rate assumptions of the safety analyses, and ensures that the calculated accidental offsite radiological doses are below 10 CFR 50.67 limits. Due to radioactive decay, containment is only required to isolate during fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 116 hours).

The containment ventilation isolation instrumentation satisfies Criterion 3 of the NRC Policy Statement.

LCO

The LCO requirements ensure that the instrumentation necessary to initiate Containment Ventilation Isolation, listed in Table 3.3.6-1, is OPERABLE.

1. <u>Manual Initiation</u>

The LCO requires two channels OPERABLE. The operator can initiate containment ventilation isolation at any time by using either of two pushbuttons in the control room. Either pushbutton actuates both trains. This action will cause actuation of Phase A and Containment Ventilation Isolation automatic containment isolation valves. Containment Ventilation Isolation can also be initiated by the manual Containment Spray buttons.

The LCO for Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

Each channel consists of one push button and the interconnecting wiring to the actuation logic cabinet.

2. <u>Automatic Actuation Logic and Actuation Relays</u>

The LCO requires two trains of Automatic Actuation Logic and Actuation Relays to be OPERABLE. The

(continued)

BASES

LCO

2. Automatic Actuation Logic and Actuation Relays (continued)

Automatic Actuation Logic and Actuation Relays actuate containment ventilation isolation upon receipt of an actuation signal from the Containment Radiation or Manual Initiation Functions. Containment ventilation isolation also initiates on an automatic safety injection (SI) signal when operating in MODES 1, 2, 3, and 4. The Bases for LCO 3.3.2, "Engineered Safety Features Actuation System (ESFAS) Instrumentation," discusses this mode of initiation.

3. Containment Radiation

The LCO specifies two required channels of radiation monitors to ensure that the radiation monitoring instrumentation necessary to initiate Containment Ventilation Isolation remains OPERABLE.

For sampling systems, channel OPERABILITY involves more than OPERABILITY of the channel electronics. OPERABILITY may also require correct valve lineups, sample pump operation, and filter motor operation, as well as detector OPERABILITY, if these supporting features are necessary for trip to occur under the conditions assumed by the safety analyses.

4. Safety Injection

Refer to LCO 3.3.2, Functions 1.a-f, for all initiating Functions and requirements.

APPLICABILITY

The Manual Initiation, Automatic Actuation Logic and Actuation Relays, and Containment Radiation Functions are required to be OPERABLE in MODES 1, 2, 3, and 4, or movement of recently irradiated fuel assemblies (i.e., fuel that has occupied part of a critical reactor core within the previous 116 hours) within containment. The Safety Injection Functions are required to be during MODES 1, 2, 3, and 4. Under these conditions, the potential exists for an accident that could release significant fission product radioactivity

(continued)

BASES

APPLICABILITY (continued)

into containment. Therefore, the containment ventilation isolation instrumentation must be OPERABLE in these MODES.

While in MODES 5 and 6 without movement of recently irradiated fuel in progress, the containment ventilation isolation instrumentation need not be OPERABLE since the potential for radioactive releases is minimized and operator action is sufficient to ensure post accident offsite doses are maintained within the limits of Reference 1.

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.6-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function are tracked separately for each Function starting from the time the Condition was entered for that Function.

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

Condition A applies to all Containment Ventilation Isolation Functions and addresses the train orientation of the relay logic and the master and slave relays for these Functions. It also addresses the failure of multiple radiation monitoring channels. If a train is inoperable or one or more channels are inoperable, operation may continue as long as the Required Action to place and maintain containment purge supply and exhaust isolation valves in their closed

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

position is met, and the applicable Conditions of LCO 3.9.3, "Containment Penetrations," are met for each valve made inoperable by failure of isolation instrumentation. The Completion Time for these Required Actions is Immediately.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.6-1 determines which SRs apply to which Containment Ventilation Isolation Functions.

SR 3.3.6.1

Performance of the CHANNEL CHECK ensures that a gross failure of the radiation monitor instrumentation has not occurred.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.2

SR 3.3.6.2 is the performance of an ACTUATION LOGIC TEST. The train being tested is placed in the test condition. All possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is tested for continuity. This verifies that the logic modules are OPERABLE and there is an intact voltage signal path to the master relay coils. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.3

SR 3.3.6.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.3 (continued)

The master relay is actuated by either a manual or automatic initiation of the function being tested. Contact operation is verified either by a continuity check of the circuit containing the master relay or proper operation of the end device during the supported equipment simulated or actual automatic actuation test. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.4

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This test verifies the capability of the radiation monitor instrumentation to initiate Containment Ventilation System isolation. The setpoint should be left consistent with the calibration procedure tolerance.

SR 3.3.6.5

SR 3.3.6.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified either by a continuity check of the circuit containing the slave relay, or by verification of proper operation of the end device during the supported equipment simulated or actual automatic actuation test. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.6

SR 3.3.6.6 is the performance of a TADOT. This test is a check of the Manual Actuation Functions

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.6.6 (continued)

Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.).

The test also includes trip devices that provide actuation signals directly to the relay logic, bypassing the analog process control equipment. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.6.7

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Deleted.

2. Deleted.

B 3.3 INSTRUMENTATION

B 3.3.7 Control Room Emergency Filtration System (CREFS) Actuation Instrumentation

BASES

BACKGROUND

The CREFS provides an enclosed control room environment from which the unit can be operated following an uncontrolled release of radioactivity. During normal operation, the Control Room Ventilation System provides control room ventilation. Upon receipt of an actuation signal, the CREFS initiates filtered ventilation and pressurization of the control room. This system is described in the Bases for LCO 3.7.9, "Control Room Emergency Filtration System."

The CREFS is actuated by the control room area radiation monitor, R-1, on a high radiation signal. A high radiation signal from R-1 will initiate both trains of CREFS. However, the trains are arranged such that train A leads train B. While both trains receive an actuation signal, train B will not start if the low flow interlock with train A clears within its set time delay. CREFS can also be initiated by manually positioning the dampers and energizing the fans. The CREFS is also actuated by a safety injection (SI) signal. The SI Function is discussed in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation."

APPLICABLE SAFETY ANALYSES

The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations.

The CREFS operates in two modes. The emergency pressurization mode serves to maintain the control room envelope at a positive pressure with respect to adjacent areas, with an air makeup rate of 400 CFM or less. Operation in the emergency circulation mode terminates the supply of unfiltered outside air to the control room envelope. These actions are necessary to ensure the control room is kept habitable for the operators stationed there during accident recovery and post accident operations by minimizing the radiation exposure of control room personnel.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The radiation monitor actuation of the CREFS during movement of irradiated fuel assemblies is the primary means to ensure control room habitability in the event of a fuel handling or waste gas decay tank rupture accident.

The CREFS actuation instrumentation satisfies Criterion 3 of the NRC Policy Statement.

LCO

The LCO requirements ensure that instrumentation necessary to initiate the CREFS is OPERABLE.

1. <u>Automatic Actuation Logic and Actuation Relays</u>

   The LCO requires two trains of Actuation Logic and Relays OPERABLE to ensure that no single random failure can prevent automatic actuation. Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b., SI, in LCO 3.3.2. The applicable MODES and specified conditions for the CREFS portion of these functions are different and less restrictive than those specified for their SI roles. If one or more of the SI functions becomes inoperable in such a manner that only the CREFS function is affected, the Conditions applicable to their SI function need not be entered. The less restrictive Actions specified for inoperability of the CREFS Functions specify sufficient compensatory measures for this case.

2. <u>Control Room Radiation Monitor</u>

   The LCO requires one Control Room Area Radiation Monitor OPERABLE to initiate the CREFS.

3. <u>Safety Injection</u>

   Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements.

(continued)

BASES

APPLICABILITY	The CREFS Functions must be OPERABLE in MODES 1, 2, 3, 4, and during the movement of irradiated fuel assemblies. Applicability to movement of irradiated fuel excludes movement of irradiated fuel within a properly sealed spent fuel shipping cask.

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by the unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by the calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.7-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function are tracked separately for each Function starting from the time the Condition was entered for that Function.

<u>A.1</u>

Condition A applies to the automatic actuation Function of the CREFS.

If one train is inoperable, 7 days are permitted to restore it to OPERABLE status. The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.9. If the channel/train cannot be restored to OPERABLE status, one CREFS train must be placed in the emergency pressurization mode of operation. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

(continued)

BASES

ACTIONS (continued)

B.1

Condition B applies to the failure of two CREFS actuation trains, or the radiation monitor channel. The Required Action is to place one CREFS train in the emergency pressurization mode of operation immediately. This accomplishes the actuation instrumentation Function that may have been lost and places the unit in a conservative mode of operation.

C.1 and C.2

Condition C applies when the Required Action and associated Completion Time for Condition A or B have not been met and the unit is in MODE 1, 2, 3, or 4. The unit must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1 and D.2

Condition D applies when the Required Action and associated Completion Time for Condition A or B have not been met when irradiated fuel assemblies are being moved. Movement of irradiated fuel assemblies must be suspended immediately to reduce the risk of accidents that would require CREFS actuation.

SURVEILLANCE REQUIREMENTS

Note has been added to the SR Table to clarify that Table 3.3.7-1 determines which SRs apply to which CREFS Actuation Functions.

SR 3.3.7.1

Performance of the CHANNEL CHECK ensures that a gross failure of radiation monitor instrumentation has not occurred.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.2

A COT is performed on the required radiation monitor channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide actuation of both CREFS trains. The setpoint should be left consistent with the unit specific calibration procedure tolerance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.3

SR 3.3.7.3 is the performance of an ACTUATION LOGIC TEST. The train being tested is placed in the test condition. All possible logic combinations, with and without applicable permissives, are tested for each protection function. In addition, the master relay coil is tested for continuity. This verifies that the logic modules are OPERABLE and there is an intact voltage signal path to the master relay coils. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.4

SR 3.3.7.4 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay. The master relay is actuated by either a manual or automatic initiation of the function being tested. Contact operation is verified either by a continuity check of the circuit containing the master relay or proper operation of the end device during the supported equipment simulated or actual automatic actuation test.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.4 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.5

SR 3.3.7.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified either by a continuity check of the circuit containing the slave relay, or by verification of proper operation of the end device during the supported equipment simulated or actual automatic actuation test. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.7.6

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. Deleted.

B 3.3 INSTRUMENTATION

B 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators (SGs) to remove decay heat from the Reactor Coolant System (RCS) upon loss of normal feedwater supply. The AFW System can provide feedwater to the SGs from any one or combination of three AFW pumps, two of which are motor driven and the third of which is steam turbine driven.

The two motor driven AFW pumps are powered from emergency busses E-1 and E-2. These busses also supply power to the motor driven AFW pump discharge isolation valves and the turbine driven AFW pump steam supply and feedwater discharge isolation valves. The turbine driven AFW pump provides a second independent and diverse means of providing auxiliary feedwater to the SGs.

Initiation of an automatic actuation signal to the turbine driven AFW pump causes the turbine steam supply valves and the pump feedwater discharge isolation valves to open. An automatic actuation signal to the motor driven AFW pumps cause the pumps to become energized and accelerate up to speed, and the feedwater discharge isolation valves to open.

Two trains of AFW actuation relay logic are used to develop the coincident signals from the process inputs. Logic train A starts one motor driven AFW pump and Logic train B starts the second motor driven AFW pump. Each logic train independently actuates the turbine driven AFW pump.

The AFW automatic actuation instrumentation is discussed in UFSAR Section 7.3.1 (Ref. 1). The instrumentation is designed in accordance with HBRSEP design criteria, which is described in UFSAR Section 3.1 (Ref. 2).

Trip Setpoints and Allowable Values

The Nominal Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted (in accordance with the Nominal Trip Setpoint when the "as left" value is within the established calibration tolerance band. A channel is required to be adjusted, if the actual Trip Setpoint is found outside the

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

"as found" calibration tolerance band, such that the actual Trip Setpoint is within the "as left" calibration tolerance band.

The Nominal Trip Setpoints used in the bistables are based on the analytical limits or design limits. The selection of these Nominal Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays accounted for in setpoint calculations and accident analyses are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those channels that must function in harsh environments as defined by 10 CFR 50.49, the Nominal Trip Setpoints and Allowable Values specified in Table 3.3.8-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Nominal Trip Setpoints, including their explicit uncertainties, is provided in the company setpoint methodology procedure (Ref. 4). The actual Nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. As noted in Table 3.3.8-1 (Note 1), a channel is considered OPERABLE with an actual Trip Setpoint value found outside its "as found" calibration tolerance band provided the Trip Setpoint value is conservative with respect to its Allowable Value and the channel is re-adjusted to within the "as left" calibration tolerance band of the Nominal Trip Setpoint.

Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) and transients will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA or transient and the equipment functions as designed.

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of calculations performed in accordance with the company setpoint methodology procedure (Ref. 4). Once a designated channel is taken out

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section.

The Nominal Trip Setpoints and Allowable Values listed in Table 3.3.8-1, are based on the methodoogy described in the company setpoint methodology procedure (Ref. 4), which incorporates all of the applicable uncertainties for each channel. The magnitudes of these uncertainties are factored into the determination of each Nominal Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater. The design basis of the AFW System is to supply water to the SGs to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the SGs at pressures corresponding to the lowest main steam safety valve (MSSV) set pressure plus 3%.

In addition, the AFW System must supply enough makeup water to replace SG secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting Design Basis Accidents (DBAs) and transients for the AFW System are as follows:

a. Feedwater Line Break (FWLB); and

b. Loss of main feedwater (MFW).

In addition, the minimum available AFW flow and system characteristics are serious considerations in the analysis of a small break loss of coolant accident (LOCA).

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BASES

APPLICABLE SAFETY ANALYSIS (continued)

The AFW System design is such that, in the event of a complete loss of offsite power, decay heat removal would continue to be assured by the availability of either the turbine driven AFW pump, or one of the two motor driven AFW pumps, along with steam discharge to the atmosphere through the MSSVs.

The AFW System actuation instrumentation satisfies Criterion 3 of the NRC Policy Statement.

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary.

The LCO requires all instrumentation performing an AFW System actuation function to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The required channels of AFW System actuation instrumentation provide unit protection in the event of any of the analyzed accidents. AFW System actuation instrumentation protection functions are as follows:

1. Steam Generator Water Level - Low Low

SG Water Level - Low Low provides protection against a loss of heat sink. A feed line break, inside or outside of containment, or a loss of MFW, would result in a loss of SG water level. SG Water Level - Low Low provides input to the SG Level Control System. Two-out-of-three signals on one SG will start the motor driven AFW pumps. Two-out-of-three signals on two SGs will start the steam driven AFW pump. Thus, three OPERABLE channels are required to satisfy the requirements with two-out-of-three logic.

2. Safety Injection (SI)

An SI signal starts the two motor driven AFW pumps. The AFW initiation functions are the same as the

(continued)

BASES

LCO

Safety Injection (SI) (continued)

requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.8-1. Instead, Table 3.3.2-1, Function 1 (Safety Injection), is referenced for all initiating functions and requirements.

3. Loss of Offsite Power

A loss of offsite power to the 480 V emergency busses will be accompanied by a loss of MFW and reactor coolant pumping power, and the subsequent need for some method of decay heat removal. Loss of offsite power is detected by undervoltage relays sensing the voltage on each 480 volt emergency (E) bus. Loss of power to either emergency bus will start the motor driven AFW pumps in the station blackout loading sequence to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip. A loss of power to the E1 bus initiates a start of the "A" AFW pump and a loss of power to the E2 bus initiates a start of the "B" AFW pump. The relays are arranged in a one-out-of-two logic, such that either relay will generate a loss of power (LOP) signal if the voltage is below the setpoint for a short period of time. The LOP signal also initiates starting the emergency diesel generators as described in the bases to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation."

4. Undervoltage - Reactor Coolant Pump (RCP)

A loss of power on 4 kV buses 1 and 4, which provide power to both MFW pumps and two RCPs, provides indication of a loss of MFW and forced flow in the RCS. Two sensors are provided on each bus, with two-out-of-two logic on both busses required to start the turbine driven AFW pump to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip.

(continued)

BASES

LCO (continued)

5. Trip of All Main Feedwater Pumps

A Trip of both MFW pumps is an indication of a loss of MFW and the subsequent need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure conditions. One contact on each MFW pump circuit breaker position provides input to the actuation logic that starts the motor driven AFW pumps. A trip of both MFW pumps starts the two motor driven AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

APPLICABILITY

Functions 1 through 4 must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW automatic actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat, or sufficient time will be available to manually place either system in operation.

Function 5 must be OPERABLE in MODES 1 and 2. This ensures that at least one SG is provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of an accident. In MODES 3, 4, and 5, the MFW pumps may be normally shut down, and thus neither pump trip is indicative of a condition requiring automatic AFW actuation.

ACTIONS

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.8-1.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the Function(s) affected. When

(continued)

BASES

ACTIONS (continued)

the Required Channels in Table 3.3.8-1 are specified (e.g., on a per bus or per pump basis), then the Condition may be entered separately for each bus or pump, etc., as appropriate.

A.1

Condition A applies to all AFW Functions, and addresses the situation where one or more channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.8-1 and to take the Required Actions for the Functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1, B.2.1, and B.2.2

Condition B applies to Undervoltage-Reactor Coolant Pump. If one channel is inoperable, 4 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. A failure of one Undervoltage-Reactor Coolant Pump channel places the Function in an unacceptable configuration. The inoperable channel must be tripped to place the Function in a one-out-of-one coincident with a two-out-of-two configuration.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 4 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

C.1, C.2.1, and C.2.2

Condition C applies to SG Water Level - Low Low. If one channel is inoperable, 6 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. A failure of one SG Water Level - Low Low channel

(continued)

BASES

ACTIONS

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

places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-two configuration.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 6 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

D.1, D.2.1, and D.2.2

Condition D applies to Loss of Offsite Power. This action recognizes the lack of manual trip provision for a failed channel. If a channel is inoperable, 48 hours are allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of this Function, the available redundancy, and the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

E.1 and E.2

Condition E applies to the AFW pump start on trip of all MFW pumps. This action addresses the relay logic for the auto start function of the AFW System on loss of all MFW pumps. The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. If a channel is inoperable, 48 hours are allowed to return it to

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

an OPERABLE status. If the Function cannot be returned to an OPERABLE status, 6 hours are allowed to place the unit in MODE 3. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above. The allowance of 48 hours to return the train to an OPERABLE status is justified in WCAP-10271-P-A (Ref. 3).

SURVEILLANCE REQUIREMENTS

The SRs for each AFW Actuation Function are identified by the SRs column of Table 3.3.8-1.

A Note has been added to the SR Table to clarify that Table 3.3.8-1 determines which SRs apply to which Functions.

The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.8.1

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

Channel deviation criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and reliability. If a channel is outside the criteria, it may be an indication

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1 (continued)

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.2

SR 3.3.8.2 is the performance of a COT. A COT is performed on each required channel to ensure the entire channel, with the exception of the transmitter sensing device, will perform the intended Function. Setpoints must be found within the tolerances and Allowable Values specified in Table 3.3.8-1.

The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology (Ref. 4). The setpoint must be left set consistent with the assumptions of the setpoint methodology (Ref. 4).

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the surveillance interval extension analysis in Reference 3 when applicable.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.3

SR 3.3.8.3 is the performance of a TADOT. This test is a check of AFW automatic pump start on loss of offsite power, undervoltage RCP, and trip of all MFW pumps Functions. Each applicable Actuation Function is tested up to, and including, the end device start circuitry. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). As noted, this SR requires the injection of a simulated or actual signal for the Trip of Main Feedwater

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.3 (continued)

Pumps Function. The injection of the signal should be as close to the sensor as practical. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.3.8.4

SR 3.3.8.4 is the performance of a CHANNEL CALIBRATION. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology (Ref. 4). The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology (Ref. 4).

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 7.3.1
2. UFSAR, Section 3.1
3. WCAP-10271-P-A, Supplement 2, Rev. 1., June 1990
4. EGR-NGGC-0153, Engineering Instrument Setpoints

B 3.4 REACTOR COOLANT SYSTEM (RCS)

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

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

The RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNB limits.

The RCS coolant average temperature limit is consistent with full power operation within the nominal operational envelope. Indications of temperature are averaged to determine a value for comparison to the limit. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. Flow rate indications are averaged to come up with a value for comparison to the limit. A lower RCS flow will cause the core to approach DNB limits.

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	result in meeting the DNBR criterion. This is the acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. A key assumption for the analysis of the events in Ref. 1 is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)." The pressurizer pressure limit and the RCS average temperature limit correspond to the analytical limits used in the safety analyses, with allowance for measurement uncertainty. The RCS DNB parameters satisfy Criterion 2 of the NRC Policy Statement.
LCO	This LCO specifies limits on the monitored process variables - pressurizer pressure, RCS average temperature, and RCS total flow rate - to ensure the core operates within the limits assumed in the safety analyses. The variables are contained in the COLR to provide operating and analysis flexibility from cycle to cycle. However, the minimum RCS flow is retained in the TS LCO. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient. RCS total flow rate contains a measurement error based on performing a precision heat balance and using the result to calibrate the RCS flow rate indicators. The numerical values for pressure, temperature, and flow rate specified in the COLR are given for the measurement location and have not been adjusted for instrument error.
APPLICABILITY	In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all

(continued)

BASES

APPLICABILITY (continued)

other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

The DNBR limit is provided in SL 2.1.1, "Reactor Core SLs." The conditions which define the DNBR limit are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

ACTIONS

A.1

RCS pressure and RCS average temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

(continued)

BASES

ACTIONS (continued)

B.1

If Required Action A.1 is not met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.1.2

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.1.3

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.1.4

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance allows the installed RCS flow instrumentation to be calibrated and verifies the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is not required to be performed until 24 hours after ≥ 90% RTP. This exception is appropriate since the heat balance requires the plant to be at a minimum of 90% RTP to obtain the stated RCS flow accuracies. The Surveillance shall be performed within 24 hours after reaching 90% RTP.

REFERENCES

1. UFSAR, Chapter 15.

2. UFSAR, Section 4.4.2.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is moderator temperature coefficient (MTC), LCO 3.1.3, "Moderator Temperature Coefficient (MTC)." In the transient and accident analyses, the MTC is assumed to be in a range from slightly positive to negative and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil ductility reference temperature when the reactor is critical.

APPLICABLE SAFETY ANALYSES

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for hot

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

zero power (HZP) is a process variable that is an initial condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal, RCCA ejection, and main steam line break accidents performed at zero power that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

All low power safety analyses assume initial RCS loop temperatures ≥ the HZP temperature of 547ºF (Ref. 1). The minimum temperature for criticality limitation provides a band of 17ºF, for critical operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality satisfies Criterion 2 of the NRC Policy Statement.

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical (k_{eff} ≥ 1.0) at a temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

APPLICABILITY

In MODE 1 and MODE 2 with k_{eff} ≥ 1.0, LCO 3.4.2 is applicable since the reactor can only be critical (k_{eff} ≥ 1.0) in these MODES.

The special test exception of LCO 3.1.8, "PHYSICS TESTS Exceptions-MODE 2," permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average

(continued)

BASES

APPLICABILITY (continued)	temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 2 with $K_{eff} < 1.0$ within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 2 with $K_{eff} < 1.0$ in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified at or above 530ºF when the low T_{avg} alarm is not reset and any RCS loop $T_{avg} < 543$ºF.

The SR is modified by a Note which states that the Surveillance is only required when any RCS loop average temperature is < 543ºF and the low T_{avg} alarm is alarming, since RCS loop average temperatures could fall below the LCO requirement without additional warning. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 15.0.4.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

Figures 3.4.3-1 and 3.4.3-2 contain P/T limit curves for heatup, cooldown, inservice leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature.

The following limitations apply to these figures:

a. Over the temperature range from COLD SHUTDOWN to hot operating conditions, the heatup rate shall not exceed 60°F/hr in any one hour period.

b. Allowable combinations of pressure and temperature for a specific cooldown rate are below and to the right of the limit lines for that rate as shown in Figure 3.4.3-2. This rate shall not exceed 100°F/hr in any one hour period. The limit lines for cooling rates between those shown in Figure 3.4.3-2 may be obtained by interpolation.

c. Primary system hydrostatic leak tests may be performed as necessary provided the test temperature limitation as noted on Figure 3.4.3-1 is not violated. The maximum hydrostatic test pressure should remain below 2485 psig.

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

(continued)

BASES

BACKGROUND (continued)

The ability of the large steel pressure vessel that contains the reactor core and its primary coolant to resist fracture constitutes and important factor in ensuring safety in the nuclear industry. The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section XI, Appendix G (Ref. 2).

The beltline region of the reactor pressure vessel is the most critical region of the vessel because it is subjected to neutron bombardment. The overall effects of fast neutron irradiation on the mechanical properties of low alloy ferritic pressure vessel steels, such as the ASTM A302 Grade B parent material of the HBRSEP Unit No. 2 reactor pressure vessel, are well documented in the literature. Generally, low alloy ferritic materials show an increase in hardness and other strength properties and a decrease in ductility and impact toughness under certain conditions of irradiation. Accompanying a decrease in impact strength is an increase in the temperature for the transition from brittle to ductile fracture.

A method for guarding against fast fracture in reactor pressure vessels is presented in Reference 2. The method utilizes fracture mechanics concepts and is based on the reference nil-ductility temperature, RT_{NDT}.

RT_{NDT} is defined as the greater of:

1. The drop weight nil-ductility transition temperature (NDTT, per ASTM E-208), or

2. The temperature 60ºF less than the 50 ft-lb (and 35 mils lateral expansion) temperature as determined from Charpy specimens oriented in a direction normal to the major working direction of the material.

(continued)

BASES

BACKGROUND (continued)

The RT_{NDT} of a given material is used to index that material to a reference stress intensity curve (K_{Ic} curve), which appears in Reference 2 and 6. The K_{Ic} curve is a lower bound of the static fracture toughness results obtained from several heats of pressure vessel steel. When a given material is indexed to the K_{Ic} curve, allowable stress intensity factors can be obtained for this material as a function of temperature. Allowable operating limits can then be determined utilizing these allowable stress intensity factors.

The Certified Material Test Reports (CMTR) for the original steam generators provided records of Charpy V-notch tests performed at +10ºF. Acceptable Charpy V-notch tests of +10ºF indicate RT_{NDT} is at or below this temperature. The steam generator lower assemblies were replaced in 1984 and the material test results indicate the highest RT_{NDT} is 60ºF or below. The ASME Code recommends that hydrostatic tests be performed at a temperature not lower than RT_{NDT} plus 60ºF, thus the pressurizing temperature for the steam generator shell is established at 120ºF to provide protection against nonductile failure at the test pressure. The value of RT_{NDT}, and in turn the operating limits of nuclear power plants, can be adjusted to account for the effects of radiation on reactor vessel material properties. The radiation embrittlement or changes in mechanical properties of a given reactor pressure vessel still can be monitored by a surveillance program such as the HBRSEP Unit No. 2 Reactor Vessel Radiation Surveillance Program (Ref. 3), where a surveillance capsule is periodically removed from the reactor pressure vessel and the encapsulated specimens tested. These data are compared to data from pertinent radiation effects studies and an increase in the Charpy V-notch 30 ft-lb temperature ($\Delta\ RT_{NDT}$) due to irradiation is added to the original $\Delta\ RT_{NDT}$ to adjust the RT_{NDT} for radiation embrittlement. This adjusted RT_{NDT} (RT_{NDT} initial + $\Delta\ RT_{NDT}$) is utilized to index the material to the K_{IC} curve and in turn to set operating limits which take into account the effects of irradiation on the reactor pressure vessel materials. Allowable pressure - temperature relationships for various heatup and cooldown rates are calculated using methods (Ref. 4) derived from Appendix G to Section XI of the ASME Boiler and Pressure Vessel Code and Code Case N-641. The approach specifies that the allowable total stress intensity factor, K_I, at any time during heatup or cooldown cannot be greater than that shown on the K_{Ic} curve in Appendix G for the metal temperature at that time. Furthermore,

(continued)

BASES

BACKGROUND (continued)

the approach applies an explicit safety factor of 2.0 on the stress intensity factor induced by pressure gradients.

Following the generation of pressure - temperature curves for both the steady state and finite heatup rate situations, the final limit curves are produced in the following fashion. First, a composite curve is constructed based on a point-by-point comparison of the steady state and finite heatup rate data. At any given temperature, the allowable pressure is taken to be the lesser of the two values taken from the curves under consideration. The composite curve is then adjusted to allow for possible errors in the pressure and temperature sensing instruments.

The use of the composite curve is mandatory in setting heatup limitations because it is possible for conditions to exist such that over the course of the heatup ramp the controlling analysis switches from the outside diameter (OD) to the inside diameter (ID) location; and the pressure limit must, at all times, be based on the most conservative case. The cooldown analysis proceeds in the same fashion as that for heatup, with the exception that the controlling location is always at the ID position. The thermal gradients induced during cooldown tend to produce tensile stresses at the ID location, and compressive stresses at the OD position. Thus, the ID flaw is clearly the worst case.

As in the case of heatup, allowable pressure - temperature relationships are generated for both steady state and finite cooldown rate situations. Composite limit curves are then constructed for each cooldown rate of interest. Adjustments are made to account for pressure and temperature instrumentation error.

The criticality limit curve includes the Reference 1 requirement that it be ≥ 40ºF above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature for Criticality."

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BASES

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing; and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follow:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

(continued)

BASES

LCO (continued)

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 1). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "RCS Minimum Temperature for Criticality"; and Safety Limit 2.1, "Safety Limits," also provide operational restrictions for pressure and temperature and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

transients in the stress analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 5), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

Condition A is modified by a Note requiring Required Action A.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. In reduced pressure and temperature conditions, the possibility of propagation with undetected flaws is decreased.

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure < 400 psig within 36 hours.

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

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by stress analysis.

The immediate Completion Time reflects the urgency of initiating action to restore the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 5), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the limits of Figures 3.4.3-1 and 3.4.3-2 is required when RCS pressure and temperature conditions are undergoing planned changes. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. 10 CFR 50, Appendix G.

2. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix G, 1995 Edition with 1996 Addenda.

3. Yanichko, S. E., "Carolina Power & Light Company, H. B. Robinson Unit No. 2 Reactor Vessel Radiation Surveillance Program," Westinghouse Nuclear Energy Systems, WCAP-7373, January, 1970.

4. Laubham, T. J., et al, "Analysis of Capsule X from the Carolina Power and Light H. B. Robinson Unit No. 2 Reactor

(continued)

BASES

REFERENCES (continued)

Vessel Surveillance Program," WCAP-15805, March 2002.

5. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

6. ASME Code Case N-641, "alternative Pressure – Temperature Relationship and Low Temperature Overpressure Projection System Requirements, Section XI, Division 1," January 17, 2000. [Includes Code Cases N-588 and N-640.]

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops - MODES 1 and 2

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission;

b. Improving the neutron economy by acting as a reflector;

c. Carrying the soluble neutron poison, boric acid;

d. Providing a second barrier against fission product release to the environment; and

e. Removing the heat generated in the fuel due to fission product decay following a unit shutdown.

The reactor coolant is circulated through three loops connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the clad fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Both transient and steady state analyses have been performed to establish the effect of flow on the departure from nucleate boiling (DNB). The transient and accident analyses for the plant have been performed assuming three RCS loops are in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the three pump coastdown, single pump locked rotor, single pump (broken shaft or coastdown), and rod withdrawal events (Ref. 1).

Steady state DNB analysis has been performed for the three RCS loop operation. For three RCS loop operation, the steady state DNB analysis, which generates the pressure and temperature Safety Limit (SL) (i.e., the departure from nucleate boiling ratio (DNBR) limit) assumes a maximum power level of 117.5% RTP. This is the design overpower condition for three RCS loop operation. The value for the accident analysis setpoint of the nuclear overpower (high flux) trip is 115% of 2339 MWt and is based on an analysis assumption that bounds possible instrumentation errors. The DNBR limit defines a locus of pressure and temperature points that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

The plant is designed to operate with all RCS loops in operation to maintain DNBR above the SL, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops - MODES 1 and 2 satisfy Criterion 2 of the NRC Policy Statement.

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, three pumps are required at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG

(continued)

BASES (continued)

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

Operation in other MODES is covered by:

LCO 3.4.5, "RCS Loops - MODE 3";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.4, "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 the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging safety systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification that each RCS loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 15.3.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loop - MODE 3

BASES

BACKGROUND

In MODE 3, the primary function of the reactor coolant is removal of decay heat and transfer of this heat, via the steam generator (SG), to the secondary plant fluid. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through three RCS loops, connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The reactor vessel contains the clad fuel. The SGs provide the heat sink. The RCPs circulate the water through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage.

In MODE 3, RCPs are used to provide forced circulation for heat removal during heatup and cooldown. The MODE 3 decay heat removal requirements are low enough that a single RCS loop with one RCP running is sufficient to remove core decay heat. However, two RCS loops are required to be OPERABLE to ensure redundant capability for decay heat removal.

APPLICABLE SAFETY ANALYSES

Whenever the reactor trip breakers (RTBs) are in the closed position and the control rod drive mechanisms (CRDMs) are energized, an inadvertent rod withdrawal from subcritical, resulting in a power excursion, is possible. Such a transient could be caused by a malfunction of the Rod Control System. In addition, the possibility of a power excursion due to the ejection of an inserted control rod is possible with the breakers closed or open. Such a transient could be caused by the mechanical failure of a CRDM.

Therefore, in MODE 3 with RTBs in the closed position and Rod Control System capable of rod withdrawal, accidental control rod withdrawal from subcritical is postulated and requires at least two RCS loops to be OPERABLE and in operation to ensure that the accident analyses limits are

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

met. For those conditions when the Rod Control System is not capable of rod withdrawal, two RCS loops are required to be OPERABLE, but only one RCS loop is required to be in operation to be consistent with MODE 3 accident analyses.

Failure to provide decay heat removal may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops - MODE 3 satisfy Criterion 3 of the NRC Policy Statement.

LCO

The purpose of this LCO is to require that at least two RCS loops be OPERABLE. In MODE 3 with the RTBs in the closed position and Rod Control System capable of rod withdrawal, two RCS loops must be in operation. Two RCS loops are required to be in operation in MODE 3 with RTBs closed and Rod Control System capable of rod withdrawal due to the postulation of a power excursion because of an inadvertent control rod withdrawal. The required number of RCS loops in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents.

With the Rod Control System not capable of control rod withdrawal, the reactor trip breakers open, or the lift disconnect switches for all control rods not fully withdrawn open, the possibility of an inadvertent control rod withdrawal transient is precluded. Alternately, with SHUTDOWN MARGIN (SDM) within the MODE 3 limit for one RCS loop in operation, a return to criticality in the event of simultaneous withdrawal of the two most reactive control rod banks as assumed in the inadvertent control rod transient analysis is precluded. Therefore, under any of these conditions only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is required to be OPERABLE to ensure that safety analyses limits are met.

The Note permits all RCPs to be de-energized for ≤ 1 hour in any 8 hour period. The purpose of the Note is to permit

(continued)

BASES (continued)

LCO (continued)

tests that are designed to validate various accident analyses values. One of these tests is validation of the pump coastdown curve used as input to a number of accident analyses including a loss of flow accident. This test is generally performed in MODE 3 during the initial startup testing program, and as such should only be performed once. If, however, changes are made to the RCS that would cause a change to the flow characteristics of the RCS, the input values must be revalidated by conducting the test again. Another test 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 or 5 and requires that the pumps be stopped for a short period of time. The Note permits the de-energizing of the pumps in order to perform this test and validate the assumed analysis values. As with the validation of the pump coastdown curve, this test should be performed only once unless the flow characteristics of the RCS are changed. The 1 hour time period specified is adequate to perform the desired tests, and operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by initial startup test procedures:

a. No operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1, thereby maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure the 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 10ºF below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

c. The Rod Control System is not capable of rod withdrawal, the reactor trip breakers are open, or the lift disconnect switches for all control rods not fully withdrawn are open. Any of these conditions

(continued)

BASES (c0ntinued)

LCO (continued)

will prevent the occurrence of an inadvertent control rod withdrawal transient. An alternate condition, described in item c.4 of the Note, is to maintain SDM within the MODE 3 limit for no RCS loops in operation as specified in the COLR. This SDM limit is sufficient to prevent a return to criticality in the event of simultaneous withdrawal of the two most reactive control rod banks as assumed in the inadvertent control rod transient analysis.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with RTBs in the closed position. The least stringent condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the RTBs open.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.4, "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).

(continued)

BASES (continued)

ACTIONS

A.1

If one required RCS loop is inoperable, redundancy for heat removal is lost. The Required Action is restoration of the required RCS loop to OPERABLE status within the Completion Time of 72 hours. This time allowance is a justified period to be without the redundant, nonoperating loop because a single loop in operation has a heat transfer capability greater than that needed to remove the decay heat produced in the reactor core and because of the low probability of a failure in the remaining loop occurring during this period.

B.1

If restoration is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

C.1

With the requirements of the LCO not met for reasons other than Conditions A or D (i.e., one of the two required RCS loops not in operation and the requirements of LCO 3.4.5 item a, b, c, or d not met), an additional RCS loop must be restored to operation within 1 hour. Should a power excursion occur due to an inadvertent control rod withdrawal transient with one of the two required RCS loops not in operation and the requirements of LCO 3.4.5 item a, b, c, or d not satisfied, the accident analysis limits may be exceeded. Therefore, only a limited time is allowed to restore an additional RCS loop to operation. Alternatively, if the requirements of the LCO 3.4.5 item a, b, c, or d are met, operation with only one RCS loop in operation would satisfy the requirements of the LCO and ensure that the possibility of a power excursion associated with an inadvertent control rod withdrawal transient is precluded. The 1 hour Completion Time is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue period of time.

(continued)

BASES

ACTIONS (continued)

D.1, D.2, and D.3

With Required Action C.1 and associated Completion Time not met, two required RCS loops inoperable, or no RCS loops in operation (except during the conditions permitted by the Note in the LCO section), all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets. All operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. A planned reduction in RCS boron concentration requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertant rod withdrawal. 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 subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification that the required loops are 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 controlled under the Surveillance Frequency Control Program.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 16% for required RCS loops. If the SG secondary side narrow range water level is < 16%, the tubes may become uncovered and the associated loop may

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.5.2 (continued)

not be capable of providing the heat sink for removal of the decay heat. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.5.3, SR 3.4.5.4, SR 3.4.5.5, and SR 3.4.5.6

Periodic verification of the alternate administrative controls established by LCO 3.4.5 items a, b, c, or d, is prudent to preclude the possibility of a power excursion associated with an inadvertent control rod withdrawal when only one RCS loop is in operation. The Surveillance Frequencies are controlled under the Surveillance Frequency Control Program.

SR 3.4.5.3, SR 3.4.5.4, SR 3.4.5.5 and SR 3.4.5.6 have been modified by Notes, which clarify that these SRs are not required to be met if the alternate requirements of SR 3.4.5.3, SR 3.4.5.4, SR 3.4.5.5, SR 3.4.5.6, as applicable, are satisfied.

SR 3.4.5.7

Verification that the required RCPs are OPERABLE ensures that safety analyses limits are met. The requirement also ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops - MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through three RCS loops connected in parallel to the reactor vessel, each loop containing an SG, a reactor coolant pump (RCP), and appropriate flow, pressure, level, and temperature instrumentation for control, protection, and indication. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and to prevent boric acid stratification.

In MODE 4, either RCPs or RHR trains can be used to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCP or one RHR train for decay heat removal and transport. The flow provided by one RCP loop or RHR train is adequate for decay heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for decay heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RCS loops and RHR trains provide this circulation.

RCS Loops - MODE 4 have been identified in the NRC Policy Statement as important contributors to risk reduction.

LCO

The purpose of this LCO is to require that at least two loops or trains be OPERABLE in MODE 4 and that one of these loops or trains be in operation. The LCO allows the two

(continued)

BASES

LCO (continued)

loops or trains that are required to be OPERABLE to consist of any combination of RCS loops and RHR trains. Any one loop or train in operation provides enough flow to remove the decay heat from the core with forced circulation. An additional loop or train is required to be OPERABLE to provide redundancy for heat removal.

Note 1 permits all RCPs or RHR pumps to be de-energized for ≤ 1 hour in any 8 hour period. The purpose of the Note is to permit tests that are designed to validate various accident analyses values.

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 at boron concentrations less than required to assure the SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure the 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 10ºF below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

c. The Rod Control System is not capable of rod withdrawal, due to the postulation of a power excursion because of an inadvertent control rod withdrawal.

(continued)

BASES

LCO (continued)

Note 2 requires that there be a steam bubble in the pressurizer or the secondary side water temperature of each SG be ≤ 50ºF above each of the RCS cold leg temperatures before the start of an RCP. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG, which has the minimum water level specified in SR 3.4.6.2.

Similarly for the RHR System, an OPERABLE RHR train comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop or train of either RCS or RHR provides sufficient circulation for these purposes. However, two circuits consisting of any combination of RCS loops and RHR trains are required to be OPERABLE to meet single failure considerations.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.5, "RCS Loops - MODE 3";
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.4, "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 one required RCS loop or RHR train is inoperable and only one required RCS loop remains OPERABLE, the intended redundancy for heat removal is lost. Action must be initiated to restore a second RCS loop or RHR train to

(continued)

BASES

ACTIONS

A.1 (continued)

OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1

If one required RCS loop or RHR train is inoperable and only one required RHR train is OPERABLE and in operation, an inoperable RCS loop or RHR train must be restored to OPERABLE status to provide a redundant means for decay heat removal.

If the parameters that are outside the limits cannot be restored, the unit must be brought to MODE 5 within 24 hours. Bringing the unit to MODE 5 is a conservative action with regard to decay heat removal. With only one RHR train OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the remaining RHR train, it would be safer to initiate that loss from MODE 5 (≤ 200ºF) rather than MODE 4 (200 to 350ºF). The Completion Time of 24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

C.1 and C.2

If no loop or train is OPERABLE or in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RCS loop or RHR train to OPERABLE status and operation must be initiated. A planned reduction in boron concentration requires forced circulation to provide proper mixing, and preserve the margin to criticality. 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 subcritical operations. The immediate Completion Times reflect the importance of

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

maintaining operation for decay heat removal. The action to restore must be continued until one loop or train is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification that one RCS loop or RHR train 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 controlled under the Surveillance Frequency Control Program.

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the secondary side narrow range water level is ≥ 16%. If the SG secondary side narrow range water level is < 16%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.6.3

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 controlled under the Surveillance Frequency Control Program.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops - MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and 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 when the RCS is not vented. 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 RCS must be capable of being pressurized for latent heat removal through the SGs to be a viable method of decay heat removal (Ref. 1). SGs used for decay heat removal must have their SG U-tubes vented/swept of non-condensable gases. 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 trains connected to the RCS, each train 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 trains in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR train for decay heat removal and transport. The flow provided by one RHR train 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 train that must be OPERABLE and in operation. The second path can be another OPERABLE RHR train or maintaining one SG with secondary side

(continued)

BASES

BACKGROUND (continued)	water level when the RCS is not vented ≥ 16% to provide an alternate method for decay heat removal when the RCS is not vented.
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 trains provide this circulation. RCS Loops - MODE 5 (Loops Filled) have been identified in the NRC Policy Statement as important contributors to risk reduction.
LCO	The purpose of this LCO is to require that at least one of the RHR trains be OPERABLE and in operation with an additional RHR train OPERABLE or one SG with secondary side water level ≥ 16% and the RCS not vented. One RHR train provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR train is required to be OPERABLE to meet single failure considerations. However, if the standby RHR train is not OPERABLE, an acceptable alternate method is one SG with the secondary side water levels ≥ 16%. Should the operating RHR train fail, the SG could be used to remove the decay heat through its sensible heat capacity, or, upon pressurization of the RCS, through latent heat removal and natural circulation flow. Note 1 permits all RHR pumps to be de-energized ≤ 1 hour in any 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 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 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

(continued)

BASES

LCO (continued)

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 at boron concentrations less than required to assure the SDM of LCO 3.1.1, therefore maintaining the margin to criticality. Boron reduction with coolant at boron concentrations less than required to assure the 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 10ºF below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR train to be inoperable and de-energized for a period of up to 2 hours, provided that the other RHR train is OPERABLE. This permits periodic surveillance tests to be performed on the inoperable train during the only time when such testing is safe and possible.

Note 3 requires that there be a steam bubble in the pressurizer or the secondary side water temperature of each SG be ≤ 50ºF above each of the RCS cold leg temperatures before the start of a reactor coolant pump (RCP). 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 trains 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 trains.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An OPERABLE SG can perform as a heat sink when it has an adequate water level, the RCS is not vented, and is OPERABLE.

(continued)

BASES

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 train of RHR provides sufficient circulation for these purposes. However, one additional RHR train is required to be OPERABLE, or the secondary side water level of at least one SG is required to be ≥ 16% with the RCS not vented.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.5, "RCS Loops - MODE 3";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled";
LCO 3.9.4, "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 train is inoperable and the required SG has secondary side water level < 16% or the RCS is vented, redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR train to OPERABLE status or to restore the required SG secondary side water level and the RCS pressure boundary. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR train is in operation, except during conditions permitted by Note 1, or if no train is OPERABLE, all operations involving introduction of coolant into the RCS with boron concentration less than required to meet the minimum SDM of LCO 3.1.1 must be suspended and action to restore one RHR train to OPERABLE status and operation must be initiated. Suspending the introduction of coolant into

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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 subcritical operations. 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 train 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 controlled under the Surveillance Frequency Control Program.

SR 3.4.7.2

Verifying that at least one SG is OPERABLE by ensuring its secondary side narrow range water level is ≥ 16% and the RCS is not vented ensures an alternate decay heat removal method in the event that the second RHR train is not OPERABLE. If both RHR trains are OPERABLE, this Surveillance is not needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.7.3 (continued) side water level is ≥ 16% in at least one SG and the RCS is not vented, this Surveillance is not needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation," August 28, 1995.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops - MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat generated in the fuel, and the transfer of this heat to the component cooling water via the residual heat removal (RHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with loops not filled, only RHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR pump for decay heat removal and transport and to require that two paths be available to provide redundancy for heat removal.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR trains provide this circulation. The flow provided by one RHR train is adequate for heat removal and for boron mixing.

RCS loops in MODE 5 (loops not filled) have been identified in the NRC Policy Statement as important contributors to risk reduction.

LCO

The purpose of this LCO is to require that at least two RHR trains be OPERABLE and one of these trains be in operation. An OPERABLE train 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 train in operation. An additional RHR train is required to be OPERABLE to meet single failure considerations.

(continued)

BASES

LCO (continued)

Note 1 permits all RHR pumps to be de-energized for ≤ 15 minutes when switching from one train 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 > 10ºF below saturation temperature. The Note prohibits boron dilution with coolant at boron concentrations less than required to assure the SDM of LCO 3.1.1 is maintained or draining operations when RHR forced flow is stopped. Testing of the RHR loop supply valves can not be performed without de-energizing all RHR pumps since the valves are common to both RHR trains. Therefore, Note 1 also allows de-energization of all RHR pumps for ≤ 15 minutes when performing testing of the RHR loop supply valves. During this testing the RHR trains are still considered to be OPERABLE since a dedicated operator is stationed at the controls of the valve and is in continuous communication with the control room. In this way, the associated valve can be reopened when a need for residual heat removal operation is indicated.

Note 2 allows one RHR train to be inoperable for a period of ≤ 2 hours, provided that the other train is OPERABLE. This permits periodic surveillance tests to be performed on the inoperable train during the only time when these tests are safe and possible.

An OPERABLE RHR train is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.

APPLICABILITY

In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops - MODES 1 and 2";
LCO 3.4.5, "RCS Loops - MODE 3";
LCO 3.4.6, "RCS Loops - MODE 4";
LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled";
LCO 3.9.4, "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).

(continued)

BASES (continued)

ACTIONS

A.1

If only one RHR train is OPERABLE and in operation, redundancy for RHR is lost. Action must be initiated to restore a second train 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 trains 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 the minimum SDM of LCO 3.1.1 must be suspended and action must be initiated immediately to restore an RHR train to OPERABLE status and operation. A planned reduction in RCS boron concentration requires forced circulation for uniform dilution, and the 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 subcritical operations. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one train is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification that one train 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 controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.4.8.2 (continued) Verification that the required number of pumps are OPERABLE ensures that additional pumps can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pumps. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation, and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level, the required heaters, and their controls and emergency power supplies. Pressurizer safety valves and pressurizer power operated relief valves are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Pressurizer Power Operated Relief Valves (PORVs)," respectively.

The intent of the LCO is to ensure that a steam bubble exists in the pressurizer prior to power operation to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions. Relatively small amounts of noncondensible gases can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control.

Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant. Unless adequate heater capacity is available, the hot, high pressure condition cannot be maintained indefinitely and still provide the required subcooling margin in the primary system. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to

(continued)

BASES

BACKGROUND (continued)	a loss of single phase natural circulation and decreased capability to remove core decay heat.
APPLICABLE SAFETY ANALYSES	In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present. Safety analyses presented in the UFSAR (Ref. 1) do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure. The maximum pressurizer water level limit satisfies Criterion 2 of the NRC Policy Statement. Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.
LCO	The LCO requirement for the pressurizer to be OPERABLE with a water level of 63.3% in MODE 1, and ≤ 92% in MODE 2 and MODE 3, ensures that a steam bubble exists. The pressurizer water level of ≤ 63.3% in MODE 1 is the normal programmed level plus 10%, which is consistent with the assumptions used in the accident analyses. The water level of ≤ 92% in MODE 2 and MODE 3 is protected by the pressurizer high level trip setpoint at 91%, and is adequate protection for the pressurizer when load rejection is not a concern. A higher water level is necessary in the pressurizer during cooldown to maintain pressurizer cooldown limits. This level requirement also assures the RCS does not go solid when criticality is achieved. Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential

(continued)

BASES

LCO (continued)

overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires ≥ 125 kW of OPERABLE pressurizer heaters, capable of being powered from the emergency power supply. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The amount needed to maintain pressure is dependent on the heat losses.

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from an emergency power supply. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

ACTIONS

A.1 and A.2

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

If the pressurizer water level is not within the limit, action must be taken to restore the plant to operation within the bounds of the safety analyses. To achieve this status, the unit must be brought to MODE 3, with the reactor trip breakers open, within 6 hours and to MODE 4 within 12 hours. This takes the unit out of the applicable MODES and restores the unit to operation within the bounds of the safety analyses.

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

B.1 and C.1

If the capacity of required pressurizer heaters is < 125 kW or the required pressurizer heaters are not capable of being powered from an emergency power supply, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering the anticipation that a demand caused by loss of offsite power would be unlikely in this period. Pressure control may be maintained during this time using normal station powered heaters.

D.1 and D.2

If a Required Action and associated Completion Time of Condition B or C is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1 (continued)

limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.9.2

The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design rating. This may be done by testing the power supply output and heater current, or by performing an electrical check on heater element continuity and resistance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.9.3

This Surveillance demonstrates that the heaters can be manually transferred from the normal to the emergency power supply and energized. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 15.
2. NUREG-0737, November 1980.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed pop type, spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The actual relief capacity for each valve, 293,330 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves or increase in the pressurizer relief tank temperature or level.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 4, MODE 5, and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

The upper and lower pressure limits are based on the ±3% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure.

(continued)

BASES

BACKGROUND (continued)	The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

APPLICABLE SAFETY ANALYSES

All accident and safety analyses in the UFSAR (Ref. 2) that require safety valve actuation assume operation of three pressurizer safety valves to limit increases in RCS pressure. The overpressure protection analysis (Ref. 3) is also based on operation of three safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal from full power;

b. Loss of reactor coolant flow;

c. Loss of external electrical load;

d. Loss of normal feedwater;

e. Loss of all AC power to station auxiliaries;

f. Locked rotor;

g. Feedwater line break; and

h. Uncontrolled RCCA Bank withdrawal from a subcritical or low power condition.

Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation is required in events c, d, and e (above) to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions.

Pressurizer safety valves satisfy Criterion 3 of the NRC Policy Statement.

LCO

The three pressurizer safety valves are set to open at the RCS design pressure (2485 psig), and within the ASME specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The pressurizer safety valve setpoint is ± 3% for OPERABILITY; however, the values are reset to ±1% during surveillance to allow for drift.

(continued)

BASES

LCO (continued)

The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

APPLICABILITY

In MODES 1, 2, and 3, OPERABILITY of three valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 conservatively included, although the listed accidents may not require the safety valves for protection.

The LCO is not applicable in MODE 4 or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head detensioned.

The Note allows entry into MODE 3 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 54 hour exception is based on 18 hour outage time for each of the three valves. The 18 hour period is derived from operating experience that hot testing can be performed in this time frame.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS Overpressure Protection System. An inoperable safety valve

(continued)

BASES

ACTIONS

A.1 (continued)

coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two or more pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. With any RCS cold leg temperatures at or below 350ºF, overpressure protection is provided by the LTOP System. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by three pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the INSERVICE TESTING PROGRAM. Pressurizer safety valves are to be tested in accordance with the requirements of Section XI of the ASME Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. UFSAR, Chapter 15.
3. WCAP-7769, Rev. 1, June 1972.
4. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and PORVs. The PORVs are air operated valves that are controlled to open at a specific set pressure when the pressurizer pressure increases and close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

Block valves, which are normally open, are located between the pressurizer and the PORVs. The block valves are used to isolate the PORVs in case of excessive leakage or a stuck open PORV. Block valve closure is accomplished manually using controls in the control room. A stuck open PORV is, in effect, a small break loss of coolant accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permit performance of surveillances on the valves during power operation.

The PORVs may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

The PORVs, their block valves, and their controls are powered from the vital buses that normally receive power from offsite power sources, but are also capable of being powered from emergency power sources in the event of a loss of offsite power.

The plant has two PORVs, each having a relief capacity of 210,000 lb/hr at 2335 psig. The functional design of the PORVs is based on maintaining pressure below the Pressurizer Pressure - High reactor trip setpoint following a step reduction of 50% of full load with steam dump. In addition,

(continued)

BASES

BACKGROUND (continued)	the PORVs minimize challenges to the pressurizer safety valves and also may be used for low temperature overpressure protection (LTOP). See LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."
APPLICABLE SAFETY ANALYSES	The PORVs and their respective block valves are provided for plant operational flexibility and for limiting the number of challenges to the pressurizer safety valves. Operation of the PORVs is not explicitly considered to be a safety-related function for overpressure protection of the reactor coolant pressure boundary (RCPB) at normal operating temperature and pressure. Plant operators employ the PORVs to depressurize the RCS in response to certain plant transients if normal pressurizer spray is not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the steam generator. Automatic operation of the PORVs in MODES 1, 2, and 3 is not classified as a safety-related function (i.e., one on which the results and conclusions of the safety analysis are based and that invokes the highest level of quality and construction). Also, an inadvertent opening of a PORV or a safety valve has been analyzed in the UFSAR (Ref. 1) as an anticipated operational occurrence (AOO) with acceptable consequences. For these reasons, although the PORVs do provide safety-related function of manual RCS pressure control for mitigation of a SGTR event, the PORVs are not classified as safety related components. Generic Letter 90-06 (Ref. 2) provided the NRC's resolution of PORV and block valve reliability concerns (Generic Issue 70), and set forth certain requirements to enhance safety. In 1995, the NRC approved an RNP LAR to add pressurizer PORVs and block valves to TS which credits them for mitigating SGTR event (Ref. 4). Inclusion of the pressurizer PORVs is consistent with the guidance provided in Generic Letter 90-06. Therefore, they are being retained in Technical Specifications.
LCO	The LCO requires the PORVs and their associated block valves to be OPERABLE for manual operation.

(continued)

BASES

LCO (continued)

An OPERABLE PORV is required to be capable of manually opening and closing, and not experiencing excessive seat leakage. Automatic control functions are not required for OPERABILITY of the PORVs.

An OPERABLE block valve may be either open and capable of being closed, or closed. Isolation of an OPERABLE PORV does not render that PORV or block valve inoperable provided the relief function of either the block valve or the PORV remains available with manual action.

Satisfying the LCO helps minimize challenges to fission product barriers.

APPLICABILITY

In MODES 1, 2, and 3, the PORV and its block valve are required to be OPERABLE to limit the potential for a small break LOCA through the flow path. The most likely cause for a PORV small break LOCA is a result of a pressure increase transient that causes the PORV to open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the RCS pressure to increase to the PORV opening setpoint. The most rapid increases will occur at the higher operating power and pressure conditions of MODES 1 and 2. The PORVs are also an alternative measure for manual actuation to mitigate a steam generator tube rupture event.

Pressure increases are less prominent in MODE 3 because the core input energy is reduced, but the RCS pressure is high. Therefore, the LCO is applicable in MODES 1, 2, and 3. The LCO is not applicable in MODES 4, 5, and 6 with the reactor vessel head in place when both pressure and core energy are decreased and the pressure surges become much less significant. LCO 3.4.12 addresses the PORV requirements in these MODES.

ACTIONS

A Note has been added to clarify that all pressurizer PORVs are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis).

(continued)

BASES

ACTIONS (continued)

A.1

PORVs may be inoperable and capable of being manually cycled (e.g., excessive seat leakage). In this condition, either the PORVs must be restored or the flow path isolated within 1 hour. The associated block valve is required to be closed, but power must be maintained to the associated block valve, since removal of power would render the block valve inoperable. This permits operation of the plant until the next refueling outage (MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem condition.

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

B.1, B.2, and B.3

If one PORV is inoperable and not capable of being manually cycled, it must be either restored, or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Times of 1 hour are reasonable, based on challenges to the PORVs during this time period, and provide the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time. Because there is at least one PORV that remains OPERABLE, an additional 72 hours is provided to restore the inoperable PORV to OPERABLE status. If the PORV cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

C.1 and C.2

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

Completion Time of 1 hour or place the associated PORV in manual control. The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation. Because at least one PORV remains OPERABLE, the operator is permitted a Completion Time of 72 hours to restore the inoperable block valve to OPERABLE status. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B, since the PORVs may not be capable of mitigating an event if the inoperable block valve is not full open. If the block valve is restored within the Completion Time of 72 hours, the power will be restored to the PORV. If it cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

D.1 and D.2

If the Required Action of Condition A, B, or C is not met, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, PORV OPERABILITY, including the ability to automatically operate, may be required. See LCO 3.4.12.

E.1, E.2, E.3, and E.4

If both PORVs are inoperable and not capable of being manually cycled, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the

(continued)

BASES

ACTIONS

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

associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation. If no PORVs are restored within the Completion Time, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, PORV OPERABILITY, including the ability to automatically operate, may be required. See LCO 3.4.12.

F.1, F.2, and F.3

If both block valves are inoperable, it is necessary to either restore the block valves within the Completion Time of 1 hour, or place the associated PORVs in manual control and restore at least one block valve within 2 hours and restore the remaining block valve within 72 hours. The Completion Times are reasonable, based on the small potential for challenges to the system during this time and provide the operator time to correct the situation.

G.1 and G.2

If the Required Actions of Condition F are not met, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, PORV OPERABILITY, including the ability to automatically operate, may be required. See LCO 3.4.12.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be opened and closed if needed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. If the block valve is closed to isolate a PORV that is capable of being manually cycled, the OPERABILITY of the block valve is of importance, because opening the block valve is necessary to permit the PORV to be used for manual control of reactor pressure. If the block valve is closed to isolate an inoperable PORV that is incapable of being manually cycled, the maximum Completion Time to restore the PORV and open the block valve is 72 hours, which is well within the allowable limits (25%) to extend the block valve Frequency of 92 days. Furthermore, these test requirements would be completed by the reopening of a recently closed block valve upon restoration of the PORV to OPERABLE status.

The Note modifies this SR by stating that it is not required to be met with the block valve closed, in accordance with the Required Action of this LCO.

SR 3.4.11.2

SR 3.4.11.2 requires a complete cycle of each PORV. Operating a PORV through one complete cycle ensures that the PORV can be manually actuated. Testing the PORVs in MODE 3 is required in order to simulate the temperature and pressure environmental effects on PORVs. In the HBRSEP Unit No. 2 PORV design, testing in MODE 4 or MODE 5 is not considered to be a representative test for assessing PORV performance under normal plant operating conditions. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The Note provides guidance to perform this SR within 12 hours of entering MODE 3. This allows adequate time to establish proper plant conditions and ensures the SR is performed in a timely manner.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.11.3

Operating the solenoid air control valves and check valves on the nitrogen accumulators ensures the PORV control system actuates properly when called upon. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.11.4

The Surveillance demonstrates that the accumulators are capable of supplying sufficient nitrogen to operate the PORVs if they are needed for RCS pressure control, and normal nitrogen and the backup instrument air systems are not available. Backup instrument air is supplied when the accumulator reaches its low pressure setpoint. This SR must be performed by isolating the normal air and nitrogen supplies from the PORVs. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 15.6.

2. Generic Letter 90-06, "Resolution of Generic Issue 70, `Power-Operated Relief Valve and Block Valve Reliability,' and Generic Issue 94, `Additional Low-Temperature Overpressure Protection for Light-Water Reactors,' Pursuant to 10 CFR 50.54(f)," dated June 25, 1990.

3. Deleted.

4. NRC Letter to CP&L, Mr. C.S. Hinnant, “Issuance of Amendment No. 162 to Facility Operating License No. DPR-23 Regarding Resolution of Generic Letter 90-06, “Resolution of Generic Issue 70, ‘Power-Operated Relief Valve and Valve Reliability,’ and Generic Issue 94,’ ‘Additional Low-Temperature Over-Pressure Protection for Light-Water Reactors’ Pursuant to 10 CFR 50.54(f),” For the H.B. Robinson Steam Electric Plant, Unit No. 2, (TAC No. M83963),” dated April 14, 1995.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System controls RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The maximum allowed PORV lift setting (allowable value) for LTOP is derived by analyses which model the performance of the LTOP System, assuming various mass input and heat input transients. Operation with a PORV lift setting less than or equal to the allowable value ensures that Reference 1 criteria will not be violated with consideration for a maximum pressure over-shoot beyond the PORV lift setting which can occur as a result of time delays in signal processing and valve opening, instrument uncertainties, and single failure. The maximum allowed PORV lift setting (allowable value) for the LTOP is updated based on the results of examinations of reactor vessel material irradiation surveillance specimens performed as required by 10 CFR 50, Appendix H.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown; a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the P/T limits.

This LCO provides RCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability

(continued)

BACKGROUND (continued)

requires compliance with the requirements of LCO 3.4.12 and a.2 and a.3. The pressure relief capacity requires either two redundant RCS relief valves or a depressurized RCS and an RCS vent of sufficient size. One RCS relief valve or the open RCS vent is the overpressure protection device that acts to terminate an increasing pressure event.

With minimum coolant input capability, the ability to provide core coolant addition is restricted. The LCO does not require the Chemical and Volume Control System (CVCS) deactivated or the SI actuation circuits blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the single SI pump and CVCS can provide adequate makeup and core cooling in the event of a loss of inventory or core cooling. If conditions require the use of more than one SI pump for makeup in the event of loss of inventory, then pumps can be made available through manual actions.

The LTOP System for pressure relief consists of two PORVs with reduced lift settings, or a depressurized RCS and an RCS vent of sufficient size. Two RCS relief valves are required for redundancy. One RCS relief valve has adequate relieving capability to keep from overpressurization for the required coolant input capability.

PORV Requirements

As designed for the LTOP System, each PORV is signaled to open if the RCS pressure approaches a limit determined by the LTOP actuation logic. The LTOP actuation logic monitors both RCS temperature and RCS pressure and determines when a condition not acceptable in the P/T limits is approached. The LTOP setpoint is biased to a minimum value at 350ºF. The reduction in temperature below 350ºF does not result in a lower setpoint. The wide range RCS temperature indications are auctioneered to select the lowest temperature signal.

The lowest temperature signal is processed through a function generator that calculates a pressure limit for that

(continued)

BASES

BACKGROUND PORV Requirements (continued)

temperature. The calculated pressure limit is then compared with the indicated RCS pressure from a wide range pressure channel. If the indicated pressure meets or exceeds the calculated value, a PORV is signaled to open.

The Trip Setpoint is the nominal value at which the LTOP bistable is set. The bistable is considered to be properly adjusted when the "as left" value is within the band for CHANNEL CALIBRATION accuracy (i.e., ± rack calibration + comparator setting accuracy). The trip setpoint and allowable value is based upon the analytical limit (i.e., the 10 CFR 50, Appendix G limit, less effects for dynamic head of operating Reactor Coolant Pumps (RCPs) and RHR pumps, static head due to location of pressure transmitters, and the pressure overshoot due to the mass and heat addition overpressure events). To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the trip setpoint. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria. The LCO specifies both the instrument setpoint and an allowable value for the setpoint that represents the maximum allowable "as found" value for the instrument to be considered OPERABLE during calibration. The actual nominal trip setpoint entered into the bistable is more conservative than that specified by the allowable value to account for changes in random measurement errors detectable by a Channel Operational Test (COT). One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the allowable value, the channel is considered OPERABLE. A detailed description of the methodology used to calculate the trip setpoints, including their explicit uncertainties, is provided in the CP&L setpoint methodology procedure which is based upon current Instrument Society of America (ISA) standards (Ref. 1).

When a PORV is opened in an increasing pressure transient, the release of coolant will cause the pressure increase to slow and reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

(continued)

BASES

BACKGROUND (continued)

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

For an RCS vent to meet the flow capacity requirement, it requires removing a pressurizer safety valve, removing a PORV's internals or physically blocking the valve stem of the PORV in the open position, and disabling its block valve in the open position. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 3) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. At about 350ºF and below, overpressure prevention falls to two OPERABLE RCS relief valves or to a depressurized RCS and a sufficient sized RCS vent. Each of these means has a limited overpressure relief capability.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the P/T limit curves are revised, the LTOP System must be re-evaluated to ensure its functional requirements can still be met using the RCS relief valve method or the depressurized and vented RCS condition.

Any change to the RCS must be evaluated against the Reference 3 analyses to determine the impact of the change on the LTOP acceptance limits.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

Mass Input Type Transients

a. Inadvertent safety injection; or

b. Charging/letdown flow mismatch.

Heat Input Type Transients

a. Inadvertent actuation of pressurizer heaters;

b. Loss of RHR cooling; or

c. Reactor coolant pump (RCP) startup with temperature asymmetry within the RCS or between the RCS and steam generators.

The following restrictions are required during the LTOP MODES to ensure that mass and heat input transients do not occur, which either of the LTOP overpressure protection means cannot handle:

a. Rendering all but one SI pump incapable of injection with all RCS cold leg temperatures ≥ 175ºF;

b. Deactivating the accumulator discharge isolation valves in their closed positions;

c. Disallowing start of an RCP if there is no steam bubble in the pressurizer, or if secondary temperature is more than 50ºF above primary temperature in any one loop. LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," provide this protection; and

d. Rendering all SI pumps incapable of injection with any cold leg temperature < 175ºF.

References 4, 5, 6, and 7 analyses demonstrate that either one RCS relief valve or the depressurized RCS and RCS vent can maintain RCS pressure below limits when the restrictions

(continued)

BASES

APPLICABLE SAFETY ANALYSES

Heat Input Type Transients (continued)

on mass and heat input described above are assumed. In addition, analyses demonstrate that the depressurized RCS and RCS vent ≥ 4.4 square inches (equivalent to two blocked open PORVs) can maintain RCS pressure below limits when only the restrictions on mass and heat input regarding accumulator injection capability and RCP starts described above are assumed. Thus, the LCO provides restrictions consistent with the mass and heat input assumptions of this analysis during the LTOP MODES. Since neither one RCS relief valve nor the RCS vent can handle the pressure transient need from accumulator injection, when RCS temperature is low, the LCO also requires the accumulators be isolated when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the LTOP analyses.

The analyses did not consider the accumulators as a credible mass input mechanism because there are multiple administrative controls to ensure isolation, including de-energizing valve control circuits (Ref. 7). Therefore, the accumulators must have their discharge valves closed and the valve power supply breakers in their open positions.

The consequences of a small break loss of coolant accident (LOCA) in LTOP MODE 4 conform to 10 CFR 50.46 and 10 CFR 50, Appendix K (Refs. 8 and 9), requirements by having a maximum of one SI pump OPERABLE and SI actuation enabled.

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below 400 psig. The setpoints are derived by analyses that model the performance of the LTOP System, assuming the limiting LTOP

(continued)

BASES

APPLICABLE SAFETY ANALYSES

PORV Performance (continued)

transient of one SI pump injecting into the RCS. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensures the Reference 1 P/T limits will be met.

The PORV setpoints will be updated when the revised reactor vessel P/T limits conflict with the LTOP analysis limits. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron irradiation. Revised limits are determined using neutron fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," discuss these examinations.

The PORVs are considered active components. Thus, the failure of one PORV is assumed to represent the worst case, single active failure.

RCS Vent Performance

With the RCS depressurized, analyses show a vent size of 4.4 square inches is capable of mitigating the allowed LTOP overpressure transient. The capacity of a vent this size is greater than the flow of the limiting transient for the LTOP configuration, two SI pumps OPERABLE and three charging pumps in operation, maintaining RCS pressure less than the maximum pressure in the LTOP analysis.

The RCS vent size will be re-evaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance.

The RCS vent is passive and is not subject to active failure.

The LTOP System satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES

LCO

This LCO requires that the LTOP System be OPERABLE. The LTOP System is OPERABLE when the minimum coolant input and pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability consistent with assumptions of the analysis when the RCS is not depressurized and RCS vent is not established, the LCO requires all accumulator discharge isolation valves closed and immobilized when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the LTOP analyses, no more than one SI pump be capable of injecting into the RCS with all RCS cold leg temperatures ≥ 175ºF, and no SI pumps be capable of injecting into the RCS with any RCS cold leg temperature < 175ºF.

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two OPERABLE PORVs; or

   A PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is within the limit required by the LTOP analyses and testing proves its ability to open at this setpoint, and motive power is available to the two valves and their control circuits.

b. A depressurized RCS and an RCS vent.

   An RCS vent is OPERABLE when open with an area of ≥ 4.4 square inches. When the RCS is depressurized and a 4.4 square inch RCS vent is established, the LCO restrictions regarding SI injection capability are not required to be met.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

(continued)

BASES

APPLICABILITY

This LCO is applicable in MODE 4, MODE 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above 350ºF. When the reactor vessel head is off, overpressurization cannot occur.

LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time allows operator action to mitigate the event.

The Applicability is modified by a Note stating that accumulator isolation is only required when the accumulator pressure is more than or at the maximum RCS pressure for the existing temperature, as allowed by the P/T limit curves. This Note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions.

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable LTOP system. There is an increased risk associated with entering MODE 4 from MODE 5 with LTOP inoperable and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1 and B.1

With two or more SI pumps capable of injecting into the RCS, and all RCS cold leg temperatures ≥ 175ºF and the requirements of LCO 3.4.12.b are not met (LCO 3.4.12.b requires the RCS to be depressurized and an RCS vent of ≥ 4.4 square inches established), or one or more SI pumps capable of injecting into the RCS with any cold leg temperature < 175ºF and the requirements of LCO 3.4.12.b are not met, RCS overpressurization is possible.

(continued)

BASES

ACTIONS

A.1 and B.1 (continued)

To immediately initiate action to restore restricted coolant input capability to the RCS reflects the urgency of removing the RCS from this condition.

C.1, D.1, and D.2

An improperly isolated accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

If isolation is needed and cannot be accomplished in 1 hour, Required Action D.1 and Required Action D.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature to > 350ºF, an accumulator pressure of 600 psig cannot exceed the LTOP limits if the accumulators are fully injected. Depressurizing the accumulators below the LTOP limit also gives this protection.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

E.1

In MODE 4, with one required PORV inoperable, the PORV must be restored to OPERABLE status within a Completion Time of 7 days. Two PORVs are required to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time considers the facts that only one of the PORVs is required to mitigate an overpressure transient and that the likelihood of an active failure of the remaining valve path during this time period is very low.

F.1

The consequences of operational events that will overpressurize the RCS are more severe at lower temperature (Ref. 10). Thus, with one of the two PORVs inoperable in MODE 5 or in MODE 6 with the head on, the Completion Time to restore two valves to OPERABLE status is 24 hours.

(continued)

BASES

ACTIONS

F.1 (continued)

The Completion Time represents a reasonable time to investigate and repair several types of relief valve failures without exposure to a lengthy period with only one OPERABLE PORV to protect against overpressure events.

G.1

The RCS must be depressurized and a vent must be established within 8 hours when:

a. Both required PORVs are inoperable; or

b. A Required Action and associated Completion Time of Condition A, B, D, E, or F is not met; or

c. The LTOP System is inoperable for any reason other than Condition A, B, C, D, E, or F.

The vent must be sized ≥ 4.4 square inches to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

The Completion Time considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, a maximum of one SI pump is verified capable of injecting into the RCS and the accumulator discharge isolation valves are verified closed and locked out. In addition when any RCS cold leg temperature is < 175ºF, it must be verified that no SI pumps are capable of injecting into the RCS.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1, SR 3.4.12.2, and SR 3.4.12.3 (continued)

The SI pump is rendered incapable of injecting into the RCS through removing the power from the pumps by racking the breakers out under administrative control. An alternate method of LTOP control may be employed using at least two independent means to prevent a pump start or to isolate the injection flow paths into the RCS such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through removal of control power fuses and at least one valve in the injection flow paths being closed, or at least one valve in the injection flow paths being locked closed or closed and deenergized.

The Surveillance Frequencies are controlled under the Surveillance Frequency Control Program.

SR 3.4.12.1 is modified by a Note indicating that this SR is only required to be met when all RCS cold leg temperatures are ≥ 175ºF and the requirements of LCO 3.4.12.b are not met. Below an RCS temperature of 175ºF with the requirements of LCO 3.4.12.b not met, all SI pumps must be incapable of injection into the RCS, as required by SR 3.4.12.2.

SR 3.4.12.2 is modified by a Note indicating that this SR is only required to be met when any RCS cold leg temperature is < 175ºF and the requirements of LCO 3.4.12.b are not met. Below an RCS temperature of 175ºF with the requirements of LCO 3.4.12.b not met, all SI pumps must be incapable of injection into the RCS. Above an RCS temperature of 175ºF, only one SI pump may be capable of injecting into the RCS as required by SR 3.4.12.1.

SR 3.4.12.4

The RCS vent of ≥ 4.4 square inches is proven OPERABLE by verifying its open condition. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.4 (continued)

The passive vent arrangement must only be open to be OPERABLE. This Surveillance is required to be met if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12.b.

SR 3.4.12.5

The PORV block valve must be verified open to provide the flow path for each required PORV to perform its function when actuated. The valve must be remotely verified open in the main control room. This Surveillance is performed if the PORV satisfies the LCO.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required removed, and the manual operator is not required locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.12.6

Performance of a COT is required within 12 hours after decreasing RCS cold leg temperature to ≤ 350°F and on each required PORV to verify and, as necessary, adjust its lift setpoint. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable COT of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The COT will verify the setpoint is within the allowed maximum limits in the LTOP analysis. PORV actuation could depressurize the RCS and is not required.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.6 (continued)

To provide operators flexibility during MODE 4 transition activities a note has been added indicating that this SR is not required to be performed until 12 hours after decreasing RCS cold leg temperature to ≤ 350°F. The 12 hour FREQUENCY considers the unlikelihood of a low temperature overpressure event during this time. The COT is required to be performed within 12 hours after entering the LTOP MODES when the PORV lift setpoint is reduced to the LTOP setting. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.12.7

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required to adjust the whole channel so that it responds and the valve opens within the required range and accuracy to known input. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-11.
3. UFSAR, Chapter 5.
4. Letter, RNP-RA/96-0141, CP&L (R. M. Krich) to NRC, "Request for Technical Specifications Change, Conversion to Improved Standard Technical Specifications Consistent with NUREG-1431, `Standard Technical Specifications-Westinghouse Plants,' Revision 1," August 30, 1996, Enclosure 5.
5. Letter, NG-77-1215, CP&L (B. J. Furr) to NRC (R. W. Reid), "Reactor Vessel Overpressurization Protection," October 31, 1977.
6. Letter, NG-77-1426, CP&L (E. E. Utley) to NRC (R. W. Reid), "Response to Overpressure Protection System Questions," December 15, 1977.

(continued)

BASES

REFERENCES (continued)

7. Report, "Pressure Mitigating Systems Transient Analysis Results," prepared by Westinghouse Electric Corporation for the Westinghouse Owners Group on Reactor Coolant System Overpressurization, July 1977, and Supplement, September 1977.

8. 10 CFR 50, Section 50.46

9. 10 CFR 50, Appendix K.

10. Generic Letter 90-06.

11. EGR-NGGC-0153, Engineering Instrument Setpoints

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE.

HBRSEP design criteria (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the facility and the public.

A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for an event resulting in steam discharge to the atmosphere assumes that primary to secondary LEAKAGE from all steam generators (SGs) is 0.3 gpm or increases to 0.3 gpm as a result of accident induced conditions. The LCO requirement to limit primary to secondary LEAKAGE through any one SG to less than or equal to 75 gallons per day is less than the conditions assumed in the safety analyses.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

For the SGTR, the activity released due to the 0.3 gpm primary to secondary LEAKAGE is relatively insignificant compared to the activity released via the ruptured tube. The safety analysis for the SGTR accident assumes 0.3 gpm total primary to secondary LEAKAGE in all generators as an initial condition. After mixing in the secondary side, the activity is then released via the SG PORVs or safeties. This release pathway continues until the SGs are isolated, which is relatively soon for the affected SG compared to the intact SGs. The dose consequences resulting from the SGTR accident are within the limits defined in 10 CFR 50.67.

The RCS operational LEAKAGE satisfies Criterion 2 of the NRC Policy Statement.

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

(continued)

LCO (continued)

Violation of this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the containment atmosphere radiation monitoring systems, condensate measuring system, dewpoint monitoring equipment, and containment sump level monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of identified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through All Steam Generators (SGs)

The limit of 75 gallons per day per SG is based on the operational LEAKAGE performance criterion in NEI 97-06, Steam Generator Program Guidelines (Ref. 3). The limit is based on operating experience with SG tube degradation mechanisms that result in tube leakage. The operational LEAKAGE criterion of 75 gallons per day in conjunction with the implementation of the Steam Generator Program is an effective measure for minimizing the frequency of steam generator tube ruptures.

(continued)

BASES (continued)

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

LCO 3.4.14, "RCS Pressure Isolation Valves (PIVs)," measures leakage through each individual PIV and can impact this LCO. Of the two PIVs in series in each isolated line, leakage measured through one PIV does not result in RCS LEAKAGE when the other is leak tight. If both valves leak and result in a loss of mass from the RCS, the loss must be included in the allowable identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE or identified LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

B.1 and B.2

If any pressure boundary LEAKAGE exists, primary to secondary LEAKAGE is not within limit, or Required Action A.1 is not met, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance.

The RCS water inventory balance must be met with the reactor at steady state operating conditions. The surveillance is modified by two notes. Note 1 states that this SR is required within 12 hours after reaching continuous steady state operation.

Steady state operation is required to perform a proper inventory balance; calculations during maneuvering are not useful and a Note requires the Surveillance to be met when steady state is established. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation."

Note 2 states that this SR is not applicable to primary to secondary LEAKAGE because LEAKAGE of 75 gallons per day cannot be measured accurately by an RCS water inventory balance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.13.2

This SR verifies that primary to secondary LEAKAGE is less or equal to 75 gallons per day through any one SG. Satisfying the primary to secondary LEAKAGE limit ensures that the operational LEAKAGE performance criterion in the Steam Generator Program is met. If this SR is not met, compliance with LCO 3.4.18, “Steam Generator Tube Integrity,” should be evaluated. The 75 gallons per day limit is measured at room temperature as described in Reference 4. The operational LEAKAGE rate limit applies to LEAKAGE through any one SG. If it is not practical to assign the LEAKAGE to an individual SG, the entire primary to secondary LEAKAGE should be conservatively assumed to be from one SG.

The Surveillance is modified by a Note which states that the Surveillance is not required to be performed until 12 hours after establishment of steady state operation. For RCS primary to secondary LEAKAGE determination, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The primary to secondary LEAKAGE is determined using continuous process radiation monitors or radiochemical grab sampling in accordance with the EPRI guidelines (Ref. 4).

REFERENCES

1. UFSAR, Section 3.1.
2. UFSAR, Chapter 15.
3. NEI 97-06, "Steam Generator Program Guidelines."
4. EPRI, "Pressurized Water Reactor Primary-to-Secondary Leak Guidelines."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Pressure Isolation Valves (PIVs)

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and HBRSEP design criteria (Refs. 1, 2, and 3), define RCS PIVs as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB), which separate the high pressure RCS from an attached low pressure system. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety.

The PIV leakage limit applies to each individual valve. Leakage through both series PIVs in a line must be included as part of the identified LEAKAGE, governed by LCO 3.4.13, "RCS Operational LEAKAGE." This is true during operation only when the loss of RCS mass through two series valves is determined by a water inventory balance (SR 3.4.13.1). A known component of the identified LEAKAGE before operation begins is the least of the two individual leak rates determined for leaking series PIVs during the required surveillance testing; leakage measured through one PIV in a line is not RCS operational LEAKAGE if the other is leaktight.

Although this specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident, that could degrade the ability for low pressure injection.

The basis for this LCO is the 1975 NRC "Reactor Safety Study" (Ref. 4) that identified potential intersystem LOCAs as a significant contributor to the risk of core melt. A subsequent study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs.

(continued)

BASES

BACKGROUND (continued)

PIVs are provided to isolate the RCS from the following typically connected systems:

a. Residual Heat Removal (RHR) System;

b. Safety Injection System; and

c. Chemical and Volume Control System.

The PIVs are listed in Table B 3.4.14-1.

Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

APPLICABLE SAFETY ANALYSES

Reference 4 identified potential intersystem LOCAs as a significant contributor to the risk of core melt. The dominant accident sequence in the intersystem LOCA category is the failure of the low pressure portion of the RHR System outside of containment. The accident is the result of a postulated failure of the PIVs, which are part of the RCPB, and the subsequent pressurization of the RHR System downstream of the PIVs from the RCS. Because the low pressure portion of the RHR System is designed for 600 psig, overpressurization failure of the RHR low pressure line would result in a LOCA outside containment and subsequent risk of core melt.

Reference 5 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

RCS PIV leakage satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

OPERABILITY of the PIVs is primarily based on meeting acceptable leakage criteria and the assurance that the RHR System PIVs cannot be opened when the RCS is pressurized greater than the RHR System piping design pressure. For a PIV to be considered OPERABLE, it must be functional as a pressure isolation device and the PIV leakage must be within limits of SR 3.4.14.1. Additionally, the RHR System interlock must be OPERABLE.

RCS PIV leakage is identified LEAKAGE into closed systems connected to the RCS. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken.

The LCO PIV leakage limit is administratively controlled to 1.0 gpm at the first test of each valve with an increasing limit based on the previous leakage rate and maximum limit of 5 gpm for subsequent tests. Leakage rates ≤ 5.0 gpm are acceptable if the latest measured leakage rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between the previous measured leakage rate and the maximum leakage rate of 5.0 gpm by > 50%. Leakage rates ≤ 5.0 gpm which are increasing at rates which reduce the margin ≤ 50% between tests provide reasonable assurance that the leakage rate will not increase beyond 5.0 gpm before the next scheduled leak test. Leakage rates < 5.0 gpm ensure the leakage will be within the capabilities of the low pressure system relief valve capacity (with some margin) and prevent overpressurization.

Reference 6 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases, the observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one half power.

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized.

(continued)

BASES

APPLICABILITY (continued)

In MODE 4, valves in the RHR flow path are not required to meet the requirements of this LCO when in, or during the transition to or from, the RHR mode of operation.

In MODES 5 and 6, leakage limits are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment.

ACTIONS

The Actions are modified by two Notes. Note 1 provides clarification that each flow path allows separate entry into a Condition. This is allowed based upon the functional independence of the flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system operability, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function.

A.1 and A.2

The flow path must be isolated by two valves. Required Actions A.1 and A.2 are modified by a Note that the valves used for isolation must meet the same leakage requirements as the PIVs and must be within the RCPB or the high pressure portion of the system.

Required Action A.1 requires that the isolation of the affected system with one valve must be performed within 4 hours. When using a manual valve to isolate the affected system, the manual valve shall be closed. As an additional measure to ensure the manual valve remains closed, the valve shall be locked in the closed position. Deactivating an automatic valve includes deenergizing the associated power supply. Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected system if leakage cannot be reduced. The 4 hour Completion Time allows the actions and restricts the operation with leaking isolation valves.

Required Action A.2 specifies that the double isolation barrier of two valves be restored by closing some other valve qualified for isolation or restoring one leaking PIV.

(continued)

BASES

ACTION

A.1 (continued)

The 72 hour Completion Time after exceeding the limit considers the time required to complete the Action and the low probability of a second valve failing during this time period.

B.1

The inoperability of the RHR interlock renders the RHR suction isolation valves capable of inadvertent opening at RCS pressures in excess of the RHR systems design pressure. If the RHR interlock is inoperable, operation may continue as long as the affected RHR suction penetration is closed by at least one closed manual or deactivated automatic valve within 4 hours. This Action accomplishes the purpose of the interlock function.

C.1 and C.2

If the Required Actions and Completion Times of Condition A or B are not met, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This Action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The allowed Completion Times are reasonable based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 and Required Action A.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit applies to each valve listed in Table B 3.4.1-1. Leakage testing requires a stable pressure condition.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

To satisfy ALARA requirements, leakage may be measured indirectly (as from the performance of pressure indicators) if accomplished in accordance with approved procedures and supported by computations showing that the method is capable of demonstrating valve compliance with the leakage criteria. Leakage rates > 1.0 gpm and ≤ 5.0 gpm are considered unacceptable if the latest measured rate exceeds the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the 5.0 gpm limit by ≥ 50%. Leakage rates > 5.0 gpm are considered to be unacceptable.

More than one valve may be tested in parallel. The combined leakage must be within the limits of this SR. In addition, the minimum differential pressure when performing the SR shall not be < 150 psid. For two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

Testing must be performed once prior to entering MODE 2 whenever the unit has been in MODE 5 for at least 7 days if leakage testing has not been performed in the previous 9 months. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

In addition, testing must be performed once after the valve has been opened by flow or exercised to ensure tight reseating. PIVs disturbed in the performance of this Surveillance should also be tested unless it has been established per Note 3 that an infinite testing loop cannot practically be avoided. Testing must be performed within 24 hours after the valve has been reseated if in MODES 1 or 2, or prior to entry into MODE 2 if not in MODES 1 or 2 at the end of the 24 hour period. Within 24 hours is a reasonable and practical time limit for performing this test after opening or reseating a valve.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

The leakage limit is to be met at the RCS pressure associated with MODES 1 and 2. This permits leakage testing at high differential pressures with stable conditions not possible in the MODES with lower pressures.

Entry into MODES 3 and 4 is allowed to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance. The Note that allows this provision is complementary to the Frequency of prior to entry into MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 9 months. In addition, this Surveillance is not required to be performed on the RHR System when the RHR System is aligned to the RCS in the shutdown cooling mode of operation. PIVs contained in the RHR shutdown cooling flow path must be leakage rate tested after RHR is secured and stable unit conditions and the necessary differential pressures are established.

SR 3.4.14.2

Verifying that the RHR interlock is OPERABLE ensures that RCS pressure will not pressurize the RHR system beyond 125% of its design pressure of 600 psig. The interlock setpoint prevents the valves from being opened and is set so the actual RCS pressure must be < 474 psig to open the valves. This setpoint ensures the RHR design pressure will not be exceeded and the RHR relief valves will not lift. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. UFSAR, Section 3.1.
4. WASH-1400 (NUREG-75/014), Appendix V, October 1975.

(continued)

BASES

REFERENCES (continued)

5. NUREG-0677, May 1980.

6. Deleted.

BASES

Table B 3.4.14-1 (page 1 of 1)
Reactor Coolant System Pressure Isolation Valves

SYSTEM	VALVE NUMBER
1. Low Pressure Safety Injection/Residual Heat Removal	
a. Loop 1, Cold Leg	875A 876A
b. Loop 2, Cold Leg	875B 876B
c. Loop 3, Cold Leg	875C 876C
2. High Pressure Safety Injection	
a. Loop 2, Hot Leg	874B
b. Loop 3, Hot Leg	874A

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

HBRSEP Design Criteria (Ref. 1) requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE.

Leakage detection systems must have the capability to detect significant reactor coolant pressure boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE.

Industry practice has shown that water flow changes of 0.5 to 1.0 gpm can be readily detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The containment sump used to collect unidentified LEAKAGE and the fan cooler condensate measuring system monitors are instrumented to alarm for increases of 0.5 to 1.0 gpm in the normal flow rates. This sensitivity is acceptable for detecting increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. Instrument sensitivities of 10^{-9} μCi/cc radioactivity for particulate monitoring and of 10^{-6} μCi/cc radioactivity for gaseous monitoring are practical for these leakage detection systems. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid responses to RCS LEAKAGE.

An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Dew point temperature measurements can thus be used to monitor humidity levels of the containment atmosphere as an

(continued)

BASES

BACKGROUND (continued)

indicator of potential RCS LEAKAGE. A 1ºF increase in dew point is well within the sensitivity range of available instruments.

Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable and should be compared to observed increases in liquid flow into or from the containment sump and condensate flow from fan coolers. Humidity level monitoring is considered most useful as an indirect alarm or indication to alert the operator to a potential problem. Humidity monitors are not required by this LCO.

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The relevance of temperature and pressure measurements are affected by containment free volume and, for temperature, detector location. Alarm signals from these instruments can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO.

APPLICABLE SAFETY ANALYSES

The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system response times and sensitivities are described in the UFSAR (Ref. 2). Multiple instrument locations are utilized, if needed, to ensure that the transport delay time of the leakage from its source to an instrument location yields an acceptable overall response time.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leakage occur detrimental to the safety of the unit and the public.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.
LCO	One method of protecting against large RCS leakage derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation. The LCO is satisfied when monitors of diverse measurement means are available. Containment sump level is monitored by two channels which indicate on the post accident monitoring panel. The function for RCS leakage detection is provided by the lowest range of each channel which provide early indication of a significant RCS leak. The R-11 and R-12 channels monitor containment particulate and gaseous activity, respectively, and the Condensate Measuring System consists of one condensate flow rate monitor channel on each of the four fan coolers. Thus, one containment sump monitor channel, in combination with either a gaseous or particulate radioactivity monitor and one containment fan cooler condensate flow rate monitor, provides an acceptable minimum. OPERABILITY of the condensate flow rate monitor includes the HVH condensate collection alarm function on the main control board in the control room.
APPLICABILITY	Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE. In MODE 5 or 6, the temperature is to be ≤ 200ºF and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

(continued)

BASES

ACTIONS

A.1 and A.2

With the required containment sump monitor inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere radioactivity monitor will provide indications of changes in leakage. Together with the atmosphere monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage.

Restoration of the required sump monitor to OPERABLE status within a Completion Time of 30 days is required to regain the function after the monitor's failure. This time is acceptable, considering the Frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

B.1.1, B.1.2, B.2.1, and B.2.2

With both gaseous and particulate containment atmosphere radioactivity monitoring instrumentation channels inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment atmosphere radioactivity monitor. Alternatively, continued operation is allowed if one fan cooler condensate flow rate monitor is OPERABLE, provided grab samples are taken every 24 hours.

The 24 hour interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

With the required containment fan cooler condensate flow rate monitor inoperable, alternative action is again required. Either SR 3.4.15.1 must be performed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information. Provided a CHANNEL CHECK is performed every 8 hours or a water inventory balance is performed every 24 hours, reactor operation may continue while awaiting restoration of a containment fan cooler condensate flow rate monitor to OPERABLE status.

The 24 hour interval provides periodic information that is adequate to detect RCS LEAKAGE.

D.1 and D.2

With the required containment atmosphere radioactivity monitor and the required containment fan cooler condensate flow rate monitor inoperable, the only means of detecting leakage is the containment sump monitor. This Condition does not provide the required diverse means of leakage detection. The Required Action is to restore either of the inoperable required monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a reduced configuration for a lengthy time period.

(continued)

BASES

ACTIONS (continued)

E.1 and E.2

If a Required Action of Condition A, B, C, or D cannot be met, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

With all required monitors inoperable, no automatic means of monitoring leakage are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.15.2

SR 3.4.15.2 requires the performance of a COT on the required containment atmosphere radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.15.3, SR 3.4.15.4, and SR 3.4.15.5

These SRs require the performance of a CHANNEL CALIBRATION for each of the required RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Surveillance Frequencies are controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 3.1.
2. UFSAR, Section 5.2.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity in the reactor coolant. The allowable levels are intended to limit the offsite dose to less than the limits of 10 CFR 50.67 for analyzed accidents.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensure that the resulting offsite doses will not exceed the 10 CFR 50.67 dose limits following an analyzed accident. The limiting accident analysis used in establishing the specified activity limits is the SGTR. Other accidents, such as the Main Steam Line Break accident also use the limits from this LCO in the dose analysis. The SGTR dose analysis (Ref. 2) assumes the specific activity of the reactor coolant at the LCO limit and an existing reactor coolant steam generator (SG) tube leakage rate of 0.3 gpm. The analysis assumes the specific activity of the secondary coolant at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.15, "Secondary Specific Activity."

(continued)

BASES

APPLICABLE SAFET ANALYSIS continued

The SGTR event is assumed to be caused by the instantaneous rupture of a steam generator tube which relieves to the faulted steam generator. The primary consequence of this event is the release of radioactivity from the reactor coolant. The analysis also assumes a concurrent loss of power, from which the loss of circulating water through the condenser eventually results in the loss of condenser vacuum. Valves in the condenser bypass lines would automatically close to protect the condenser, thereby causing steam relief directly to the atmosphere from the steam generator PORVs or safety valves. This direct relief of activity from the ruptured tube would continue until the faulted steam generator is isolated. Additional releases due to primary to secondary LEAKAGE would continue from the SG PORVs or safety valves on the intact SGs until they were isolated.

Since no fuel failures are assumed to occur from the event, the specific activity at the LCO limit, and the amount of coolant released would determine the radioactivity that was released to the atmosphere.

The safety analysis shows the radiological consequences of an SGTR accident are within the dose limits of 10 CFR 50.67. Operation with iodine specific activity levels greater than the LCO limit is permissible for 48 hours, if the activity level does not exceed 60 μCi/gm.

The permissible iodine level of 60 μCi/gm or less is acceptable because of the low probability of a SGTR accident occurring during the established 48 hour time limit. The occurrence of an SGTR accident at 60 μCi/gm would increase the calculated site boundary dose levels, but still be within 10 CFR 50.67 dose limits.

Limits on RCS specific activity also ensure the radiation shielding design of the plant remains acceptable for plant personnel radiation protection.

RCS specific activity satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO	The specific iodine activity is limited to 0.25 μCi/gm DOSE EQUIVALENT I-131, and the gross specific activity in the reactor coolant is limited to the number of μCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy of the sum of the average beta and gamma energies of the coolant nuclides). The limits on DOSE EQUIVALENT I-131 and gross specific activity ensure the 2 hour dose to an individual at the site boundary during the DBA will be less than the allowed dose. The SGTR accident analysis (Ref. 2) shows that the 2 hour site boundary dose levels are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of an SGTR, lead to site boundary doses that exceed the 10 CFR 50.67 dose limits.
APPLICABILITY	In MODES 1 and 2, and in MODE 3 with RCS average temperature ≥ 500°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and gross specific activity are necessary to contain the potential consequences of an SGTR to within the acceptable site boundary dose values. For operation in MODE 3 with RCS average temperature < 500°F, and in MODES 4 and 5, the release of radioactivity in the event of a SGTR is unlikely since the saturation pressure of the reactor coolant is below the lift pressure settings of the main steam safety valves.
ACTIONS	A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate that the Dose Equivalent I-131 concentration is ≤ 60 μCi/gm. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is done to continue to provide a trend.

The DOSE EQUIVALENT I-131 must be restored to within limits within 48 hours. The Completion Time of 48 hours is required, if the limit violation resulted from normal iodine spiking.

B.1

With the gross specific activity in excess of the allowed limit, the unit must be placed in a MODE in which the requirement does not apply.

The change within 6 hours to MODE 3 and RCS average temperature < 500°F lowers the saturation pressure of the reactor coolant below the setpoints of the main steam safety valves and prevents venting the SG to the environment in an SGTR event. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 below 500ºF from full power conditions in an orderly manner and without challenging plant systems.

C.1

If a Required Action and the associated Completion Time of Condition A is not met or if the DOSE EQUIVALENT I-131 is > 60 μCi/gm, the reactor must be brought to MODE 3 with RCS average temperature < 500ºF within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the gross specific activity of the reactor coolant. The analysis shall consist of a qualitative measurement of the total radioactivity of the primary coolant in units of μCi/gm. While basically a quantitative measure of radionuclides with half lives longer than 15 minutes, excluding iodines, this measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in gross specific activity.

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The Surveillance is applicable in MODES 1 and 2, and in MODE 3 with T_{avg} at least 500ºF. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.16.2

This Surveillance is performed in MODE 1 only to ensure iodine remains within limit during normal operation and following fast power changes when fuel failure is more apt to occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The Frequency, between 2 and 6 hours after a power change ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following fuel failure; samples at other times would provide inaccurate results.

SR 3.4.16.3

A radiochemical analysis for $\bar{E}$ determination is required with the plant operating in MODE 1 equilibrium conditions. The $\bar{E}$ determination directly relates to the LCO and is required to verify plant operation within the specified gross activity LCO limit. The analysis for $\bar{E}$ is a measurement of the average energies per disintegration for isotopes with half lives longer than

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.16.3 (continued)

15 minutes, excluding iodines. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR has been modified by a Note that indicates the ê determination is required to be performed within 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for at least 48 hours. This ensures that the radioactive materials are at equilibrium so the analysis for $\bar{E}$ is representative and not skewed by a crud burst or other similar abnormal event.

REFERENCES

1. 10 CFR 100.11.

2. UFSAR, Section 15.6.3.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.17 Chemical and Volume Control System (CVCS)

BASES

BACKGROUND

The function of the CVCS is to provide a source of borated makeup water to the RCS at operating temperatures and pressures. The CVCS provides water injection to the Reactor Coolant Pump (RCP) seals and has the additional functions of removing impurities in the RCS, controlling RCS chemistry, and controlling RCS inventory of both Boron and coolant during heatup and cooldown of the reactor (Ref. 1).

During plant operation, reactor coolant flows through the letdown line from a loop cold leg on the discharge side of the RCP. The coolant passes through heat exchangers to reduce the temperature of the coolant. After passing through one of the mixed bed demineralizers, where ionic impurities are removed, coolant flows through the reactor coolant filters and enters the volume control tank through a spray nozzle. From the volume control tank, the coolant flows to the charging pumps which raise the pressure above that in the RCS. The coolant is normally returned to the cold leg of another loop on the discharge side of the pump via a charging line.

A portion of the high pressure charging flow is injected by the charging pumps into the RCPs between the RCP impeller and the shaft seal so that the seals are not exposed to high temperature reactor coolant. Part of the flow is the shaft seal leakage flow and the remainder enters the RCS through a labyrinth seal on the pump shaft. The shaft seal leakage flow cools the lower radial bearing, passes through the seals, is filtered, cooled in the seal water heat exchanger, and returned to the volume control tank. Seal injection flow is measured by a flow indicator for each RCP.

Seal water inleakage to the RCS requires a continuous letdown of reactor coolant to maintain the desired inventory. In addition, bleed and feed of reactor coolant is required for removal of impurities and adjustment of boric acid in the reactor coolant

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(continued)

BASES

BACKGROUND (continued)

Makeup water to the RCS is provided by the CVCS from the following sources:

a. The primary water storage tank, in combination with boric acid storage tanks provides water for makeup and RCS boron concentration adjustments, and

b The Refueling Water Storage Tank (RWST) which, via one of two pathways, supplies borated water for emergency makeup.

Three positive displacement charging pumps with variable speed drives are used to supply charging flow to the RCS. The speed of each pump can be controlled manually or automatically. During normal operation, one or more charging pumps are operating and the speed of the automatically controlled pump is modulated in accordance with pressurizer level.

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that sufficient seal water injection is provided to the RCPs. The HBRSEP, Unit No. 2 Individual Plant Examination (IPE), submitted to the NRC by letter dated August 31, 1992 (Ref. 2), found that the RCP seal injection function was a significant contributor to the overall core damage frequency. The plant event sequences of interest are a loss of all component cooling water which results in a loss of all charging capability and a loss of backup cooling to the RCP seals. The loss of all component cooling water is initiated by a loss of all AC power (station blackout), a multiple failure of component cooling, or a multiple failure resulting in loss of all service water cooling capability. Without either component cooling capability or charging flow to the RCP seals, the RCP seals fail resulting in a small break Loss-of-Coolant Accident (LOCA). The loss of component cooling also results in a loss of cooling to the containment spray pumps and safety injection pumps. Hence, while the loss of seal injection capability is not the initiating event for the risk significant event sequences, the charging pumps perform a key function, which if lost, enables continuation of the risk significant event sequence to a state result of core damage.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

The CVCS seal injection function satisfies Criterion 4 of the NRC Policy Statement.

LCO

In MODES 1, 2, 3, and 4, RCP seal injection is required to be OPERABLE to ensure that RCP seal integrity is maintained.

The CVCS is required to maintain minimum seal injection flow as measured by flow indication or by alternate means defined in procedures, to maintain a redundant charging capability to provide seal injection flow to the RCPs, and to maintain a redundant source of makeup water to the charging pumps.

Indication that RCP seal injection flow is within limits can be determined from indicated flow measurement to each RCP or by other means as described in procedures. RCP seal integrity is assured when seal injection flow meets surveillance requirements.

Two charging pumps powered from a normal power source are required to be OPERABLE. The emergency power supply sources are not required for the charging pumps to be OPERABLE. The charging pumps are also OPERABLE if they are powered from the emergency power source in lieu of the normal power source.

The CVCS is required to have a redundant means to provide a supply of makeup water to the charging pumps. Two supplies of makeup water are available from the RWST via a remotely operated air operated valve and locally operated manual valve. These sources provide both required Makeup Water Pathways from the RWST.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CVCS OPERABILITY requirement for the risk significant function of injection to the RCP seals, is based upon full power operation. Although reduced power and MODES 3 and 4 conditions would result in less severe consequences of the risk significant sequences and a longer period of time would elapse before core damage occurs, the RCP seals must continue to be cooled in the lower MODES.

(continued)

APPLICABILITY (continued)

In MODES 5 and 6, plant conditions are such that the risk significance of loss of seal injection to the RCPs is significantly reduced. Therefore, CVCS OPERABILITY requirements in these MODES are not maintained in Technical Specifications.

ACTIONS

A.1

With one required charging pump inoperable, the inoperable pump must be returned to OPERABLE status within 24 hours. The 24 hour Completion Time is reasonable, based upon the original licensing basis.

B.1

With one Makeup Water Pathway inoperable, the inoperable components must be returned to OPERABLE status within 24 hours. The 24 hour Completion Time is consistent with the time permitted to restore an inoperable charging pump to OPERABLE status. Because there are two means of establishing Makeup Water Pathways, the remaining OPERABLE pathway will provide the required source of makeup water.

A footnote allows for a 72 hour completion time for the remainder of Cycle 26 Based on License Amendment No. 223.

C.1 and C.2

If the inoperable components identified in Required Actions A.1 and B.1 cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1, D.2 and D.3

If seal injection to any RCP is not within limit and both required charging pumps are inoperable, adequate makeup to the RCP seals is not assured. In addition, adequate makeup to the RCS is not assured and the RCS inventory will begin to reduce. Backup cooling is provided to the RCP seals by the Component Cooling Water System. Since adequate means of

(continued)

ACTIONS (continued)

D.1, D.2 and D.3

adding boron to the RCS to achieve cold shutdown conditions are also not available, it is imprudent to bring the plant to MODE 5 where the LCO no longer applies. Therefore, Required Action D.1 requires that action be initiated to restore seal injection to the RCPs to within limits immediately. Required Actions D.2 and D.3 require that the plant be brought to MODE 3 within 6 hours and be depressurized to a pressure < 1400 psig within 12 hours. At this pressure, the Safety Injection (SI) system can be used to maintain RCS inventory until charging can be reestablished. The allowed Completion Times for Required Actions D.2 and D.3 are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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

If seal injection to any RCP is not within limit and one required charging pump is OPERABLE, adequate makeup to the RCP seals is not assured. Backup cooling is provided to the RCP seals by the component cooling water system. The plant must be brought to a condition where the LCO no longer applies. Required Action E.1 requires that action be intitiated to restore seal injection to the affected RCP(s) immediately. Required Actions E.2 and E.3 require that the plant be brought to MODE 3 in 6 hours and MODE 5 in 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1 and F.2

If both Makeup Water Pathways from the RWST are inoperable, adequate makeup to the RCP seals is not assured. Backup cooling is provided to the RCP seals by the Component Cooling Water System. The plant must be brought to a condition where the LCO no longer applies. The allowed Completion Times for Required Actions F.1 and F.2 are reasonable, based on operating experience, to reach the

(continued)

BASES

ACTIONS

F.1 and F.3 (continued)

required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.17.1

Verification of seal injection to the RCP seals ensures that adequate cooling to the RCP seals is maintained. Verification of seal injection flow is accomplished by direct measurement of seal injection flow or by other means as defined in procedures. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.4.17.2

Verification of seal injection flow to the RCP seals via the Makeup Water Pathways ensures that adequate cooling to the RCP seals can be maintained from the RWST. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Verification of OPERABILITY of the Makeup Water Pathways from the RWST is also satisfied by SR 3.5.4.2, which verifies an adequate inventory of makeup water.

REFERENCES

1. UFSAR Paragraph 9.3.4.
2. CP&L Letter to NRC, 'Submittal of Independent Plant Examination (IPE)," dated August 31, 1992.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.18 Steam Generator (SG) Tube Integrity

BASES

BACKGROUND

Steam generator (SG) tubes are small diameter, thin walled tubes that carry primary coolant through the primary to secondary heat exchangers. The SG tubes have a number of important safety functions. Steam generator tubes are an integral part of the reactor coolant pressure boundary (RCPB) and, as such, are relied on to maintain the primary system's pressure and inventory. The SG tubes isolate the radioactive fission products in the primary coolant from the secondary system. In addition, as part of the RCPB, the SG tubes are unique in that they act as the heat transfer surface between the primary and secondary systems to remove heat from the primary system. This Specification addresses only the RCPB integrity function of the SG. The SG heat removal function is addressed by LCO 3.4.4, "RCS Loops – MODES 1 and 2," LCO 3.4.5, "RCS Loops - MODE 3," LCO 3.4.6, "RCS Loops - MODE 4," and LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled."

SG tube integrity means that the tubes are capable of performing their intended RCPB safety function consistent with the licensing basis, including applicable regulatory requirements.

Steam generator tubing is subject to a variety of degradation mechanisms. Steam generator tubes may experience tube degradation related to corrosion phenomena, such as wastage, pitting, intergranular attack, and stress corrosion cracking, along with other mechanically induced phenomena such as denting and wear. These degradation mechanisms can impair tube integrity if they are not managed effectively. The SG performance criteria are used to manage SG tube degradation.

Specification 5.5.9, "Steam Generator (SG) Program," requires that a program be established and implemented to ensure that SG tube integrity is maintained. Pursuant to Specification 5.5.9, tube integrity is maintained when the SG performance criteria are met. There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. The SG performance criteria are described in Specification 5.5.9. Meeting the SG performance criteria provides reasonable assurance of

(continued)

BASES (continued)

BACKGROUND (continued)

maintaining tube integrity at normal and accident conditions. The processes used to meet the SG performance criteria are defined by the Steam Generator Program Guidelines (Ref. 1).

APPLICABLE SAFETY ANALYSES

The steam generator tube rupture (SGTR) accident is the limiting design basis event for SG tubes and avoiding an SGTR is the basis for this Specification. The analysis of a SGTR event assumes a bounding primary to secondary LEAKAGE rate greater than the operational LEAKAGE rate limits in LCO 3.4.13, "RCS Operational LEAKAGE," plus the leakage rate associated with a double-ended rupture of a single tube.

The analysis for design basis accidents and transients other than a SGTR assume the SG tubes retain their structural integrity (i.e., they are assumed not to rupture.) In these analyses, the steam discharge to the atmosphere is based on the total primary to secondary LEAKAGE from all SGs of 0.3 gallon per minute or is assumed to increase to 0.3 gallon per minute as a result of accident induced conditions. For accidents that do not involve fuel damage, the primary coolant activity level of DOSE EQUIVALENT I-131 is assumed to be equal to the LCO 3.4.16, "RCS Specific Activity," limits. For accidents that assume fuel damage, the primary coolant activity is a function of the amount of activity released from the damaged fuel. The dose consequences of these events are within the limits of GDC 19 (Ref. 2) and 10 CFR 50.67 (Ref. 3) or the NRC approved licensing basis (e.g., a small fraction of these limits).

Steam generator tube integrity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

(continued)

LCO

The LCO requires that SG tube integrity be maintained. The LCO also requires that all SG tubes that satisfy the plugging criteria be plugged in accordance with the Steam Generator Program.

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. If a tube was determined to satisfy the plugging criteria but was not plugged, the tube may still have tube integrity.

In the context of this Specification, the safety significant portion of a SG tube from 18.11 inches below the top of the tubesheet on the hot leg to 18.11 inches below the top of the hot leg is subject to inspection. The tube-to-tubesheet weld is not considered part of the tube.

A SG tube has tube integrity when it satisfies the SG performance criteria. The SG performance criteria are defined in Specification 5.5.9, "Steam Generator Program," and describe acceptable SG tube performance. The Steam Generator Program also provides the evaluation process for determining conformance with the SG performance criteria.

There are three SG performance criteria: structural integrity, accident induced leakage, and operational LEAKAGE. Failure to meet any one of these criteria is considered failure to meet the LCO.

The structural integrity performance criterion provides a margin of safety against tube burst or collapse under normal and accident conditions, and ensures structural integrity of the SG tubes under all anticipated transients included in the design specification. Tube burst is defined as, "The gross structural failure of the tube wall. The condition typically corresponds to an unstable opening displacement (e.g., opening area increased in response to constant pressure) accompanied by ductile (plastic) tearing of the tube material at the ends of the degradation." Tube collapse is defined as, "For the load displacement curve for a given structure, collapse occurs at the top of the load versus displacement curve where the slope of the curve becomes zero." The structural integrity performance criterion provides guidance on assessing loads that have a

(continued)

BASES (continued)

LCO
Continued

significant effect on burst or collapse. In that context, the term "significant" is defined as "An accident loading condition other than differential pressure is considered significant when the addition of such loads in the assessment of the structural integrity performance criterion could cause a lower structural limit or limiting burst/collapse condition to be established." For tube integrity evaluations, except for circumferential degradation, axial thermal loads are classified as secondary loads. For circumferential degradation, the classification of axial thermal loads as primary or secondary loads will be evaluated on a case-by-case basis. The division between primary and secondary classifications will be based on detailed analysis and/or testing.

Structural integrity requires that the primary membrane stress intensity in a tube not exceed the yield strength for all ASME Code, Section III, Service Level A (normal operating conditions) and Service Level B (upset or abnormal conditions) transients included in the design specification. This includes safety factors and applicable design basis loads based on ASME Code, Section III, Subsection NB (Ref. 4) and Draft Regulatory Guide 1.121 (Ref. 5).

The accident induced leakage performance criterion ensures that the primary to secondary LEAKAGE caused by a design basis accident, other than a SGTR, is within the accident analysis assumptions. The accident analysis assumes that accident induced leakage does not exceed 150 gpd per SG. The accident induced leakage rate includes any primary to secondary LEAKAGE existing prior to the accident in addition to primary to secondary LEAKAGE induced during the accident.

The operational LEAKAGE performance criterion provides an observable indication of SG tube conditions during plant operation. The limit on operational LEAKAGE is contained in LCO 3.4.13, "RCS Operational LEAKAGE," and limits primary to secondary LEAKAGE through any one SG to 75 gallons per day. This limit is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line break. If this amount of LEAKAGE is due to more than one crack, the cracks are very small, and the above assumption is conservative.

(continued)

APPLICABILITY

Steam generator tube integrity is challenged when the pressure differential across the tubes is large. Large differential pressures across SG tubes can only be experienced in MODE 1, 2, 3, or 4.

RCS conditions are far less challenging in MODES 5 and 6 than during MODES 1, 2, 3, and 4. In MODES 5 and 6, primary to secondary differential pressure is low, resulting in lower stresses and reduced potential for LEAKAGE.

ACTIONS

The ACTIONS are modified by a Note clarifying that the Conditions may be entered independently for each SG tube. This is acceptable because the Required Actions provide appropriate compensatory actions for each affected SG tube. Complying with the Required Actions may allow for continued operation, and subsequently affected SG tubes are governed by subsequent Condition entry and application of associated Required Actions.

A.1 and A.2

Condition A applies if it is discovered that one or more SG tubes examined in an inservice inspection satisfy the tube plugging criteria but were not plugged in accordance with the Steam Generator Program as required by SR 3.4.18.2. An evaluation of SG tube integrity of the affected tube(s) must be made. Condition A does not apply to the occurrence of primary to secondary LEAKAGE, which is monitored and maintained in accordance with LCO 3.4.13. Steam generator tube integrity is based on meeting the SG performance criteria described in the Steam Generator Program. The SG plugging criteria define limits on SG tube degradation that allow for flaw growth between inspections while still providing assurance that the SG performance criteria will continue to be met. In order to determine if a SG tube that should have been plugged has tube integrity, an evaluation must be completed that demonstrates that the SG performance criteria will continue to be met until the next refueling outage or SG tube inspection. The tube integrity determination is based on the estimated condition of the tube at the time the situation is discovered and the estimated growth of the degradation prior to the next SG tube inspection. If it is determined that tube integrity is not being maintained, Condition B applies.

(continued)

BASES (continued)

ACTIONS (continued)

A.1 and A.2 (continued)

A completion time of 7 days is sufficient to complete the evaluation while minimizing the risk of plant operation with an SG tube that may not have tube integrity.

If the evaluation determines that the affected tub(s) have tube integrity, Required Action A.2 allows plant operation to continue until the next refueling outage or SG inspection provided the inspection interval continues to be supported by an operational assessment that reflects the affected tubes. However, the affected tube(s) must be plugged prior to entering MODE 4 following the next refueling outage or SG inspection. This Completion Time is acceptable since operation until the next inspection is supported by the operational assessment.

B.1 and B.2

If the Required Actions and associated Completion Times of Condition A are not met or if SG tube integrity is not being maintained, the reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the desired plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.18.1

During shutdown periods the SGs are inspected as required by this SR and the Steam Generator Program. NEI 97-06, Steam Generator Program Guidelines (Ref. 1), and its referenced EPRI Guidelines, establish the content of the Steam Generator Program. Use of the Steam Generator Program ensures that the inspection is appropriate and consistent with accepted industry practices.

During SG inspections a condition monitoring assessment of the SG tubes is performed. The condition monitoring

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.18.1 (continued)

assessment determines the “as found” condition of the SG tubes. The purpose of the condition monitoring assessment is to ensure that the SG performance criteria have been met for the previous operating period.

The Steam Generator Program determines the scope of the inspection and the methods used to determine whether the tubes contain flaws satisfying the tube plugging criteria. Inspection scope (i.e., which tubes or areas of tubing within the SG are to be inspected) is a function of existing and potential degradation locations. The Steam Generator Program also specifies the inspection methods to be used to find potential degradation. Inspection methods are a function of degradation morphology, nondestructive examination (NDE) technique capabilities, and inspection locations.

The Steam Generator Program defines the Frequency of SR 3.4.18.1. The Frequency is determined by the operational assessment and other limits in the SG examination guidelines (Ref. 6). The Steam Generator Program uses information on existing degradations and growth rates to determine an inspection Frequency that provides reasonable assurance that the tubing will meet the SG performance criteria at the next scheduled inspection. In addition, Specification 5.5.9 contains prescriptive requirements concerning inspection intervals to provide added assurance that the SG performance criteria will be met between scheduled inspections. If crack indications are found in any SG tube, the maximum inspection interval for each affected and potentially affected SG is restricted by Specification 5.5.9 until subsequent inspections support extending the inspection interval.

SR 3.4.18.2

During an SG inspection, any inspected tube that satisfies the Steam Generator Program plugging criteria is removed from service by plugging. The tube plugging criteria delineated in Specification 5.5.9 are intended to ensure that tubes accepted for continued service satisfy the SG performance criteria with allowance for error in the flaw size measurement and for future flaw growth. In addition, the tube plugging criteria, in conjunction with other elements of the Steam Generator Program, ensure that the SG performance criteria will continue to be met until the next inspection of the subject tube(s). Reference 1 provides guidance for performing operational assessments to verify that the tubes remaining in service will continue to meet the SG performance criteria.

(continued)

BASES (Continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.18.2 (continued)

The Frequency of prior to entering MODE 4 following a SG inspection ensures that the Surveillance has been completed and all tubes meeting the plugging criteria are plugged prior to subjecting the SG tubes to significant primary to secondary pressure differential.

REFERENCES

1. NEI 97-06, "Steam Generator Program Guidelines."
2. 10 CFR 50 Appendix A, GDC 19.
3. 10 CFR 50.67.
4. ASME Boiler and Pressure Vessel Code, Section III, Subsection NB.
5. Draft Regulatory Guide 1.121, "Basis for Plugging Degraded Steam Generator Tubes," August 1976.
6. EPRI, "Pressurized Water Reactor Steam Generator Examination Guidelines."

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Accumulators

BASES

BACKGROUND

The functions of the ECCS accumulators are to supply water to the reactor vessel during the blowdown phase of a loss of coolant accident (LOCA), to provide inventory to help accomplish the refill phase that follows thereafter, and to provide Reactor Coolant System (RCS) makeup for a small break LOCA.

The blowdown phase of a large break LOCA is the initial period of the transient during which the RCS departs from equilibrium conditions, and heat from fission product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. The blowdown phase of the transient ends when the RCS pressure falls to a value approaching that of the containment atmosphere.

In the refill phase of a LOCA, which immediately follows the blowdown phase, reactor coolant inventory has vacated the core through steam flashing and ejection out through the break. The core is essentially in adiabatic heatup. The balance of accumulator inventory is then available to help fill voids in the lower plenum and reactor vessel downcomer so as to establish a recovery level at the bottom of the core and ongoing reflood of the core with the addition of safety injection (SI) water.

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. The accumulators are passive components, since no operator or control actions are required in order for them to perform their function. Internal accumulator tank pressure is sufficient to discharge the accumulator contents to the RCS, if RCS pressure decreases below the accumulator pressure.

Each accumulator is piped into an RCS cold leg via an accumulator line and is isolated from the RCS by a motor operated isolation valve and two check valves in series. The accumulator isolation valves are maintained open in a deenergized state to ensure accumulator availability when the pressurizer pressure is > 1000 psig.

(continued)

BASES

BACKGROUND (continued)

The accumulator size, water volume, and nitrogen cover pressure are selected so that two of the three accumulators are sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that two accumulators are adequate for this function is consistent with the LOCA assumption that the entire contents of one accumulator will be lost via the RCS pipe break during the blowdown phase of the LOCA.

APPLICABLE SAFETY ANALYSES

The accumulators are assumed OPERABLE in both the large and small break LOCA analyses at full power (Ref. 2). These are the Design Basis Accidents (DBAs) that establish the acceptance limits for the accumulators. Reference to the analyses for these DBAs is used to assess changes in the accumulators as they relate to the acceptance limits.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of ECCS flow. In the early stages of a LOCA, with or without a loss of offsite power, the accumulators provide the sole source of makeup water to the RCS. The assumption of loss of offsite power is required by regulations and conservatively imposes a delay wherein the ECCS pumps cannot deliver flow until the emergency diesel generators start, come to rated speed, and go through their timed loading sequence. In cold leg break scenarios, the entire contents of one accumulator are assumed to be lost through the break.

During a LOCA, the accumulators discharge to the RCS as soon as RCS pressure decreases to below accumulator pressure.

As a conservative estimate, no credit is taken for ECCS pump flow until an effective delay has elapsed. This delay accounts for the diesels starting and the pumps being loaded and delivering full flow. During this time, the accumulators are analyzed as providing the sole source of emergency core cooling. No operator action is assumed during the blowdown stage of a large break LOCA.

The worst case small break LOCA analyses also assume a time delay before pumped flow reaches the core. For the larger

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated solely by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and safety injection pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the safety injection pumps become solely responsible for terminating the temperature increase.

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 (Ref. 3) will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200ºF;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react; and

d. Core is maintained in a coolable geometry.

Since the accumulators discharge during the blowdown phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

The accumulator volume used in the large break LOCA analysis is a nominal value of 833 ft^3. This is acceptable since the large break LOCA analysis is not particularly sensitive to the 8 ft^3 difference between the nominal volume and the minimum volume of 825 ft^3. The accumulator volume used in the small break LOCA analysis is the minimum value of 825 ft^3. Although this is not a key parameter used in the small break LOCA analysis, the minimum value was used in the analysis. Use of either the nominal or minimum volume is acceptable since the accumulators do not empty in a small break LOCA.

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The minimum boron concentration setpoint is used in the post LOCA boron concentration calculation. The calculation is performed to assure reactor subcriticality in a post LOCA environment. A reduction in the accumulator minimum boron concentration would produce a subsequent reduction in the available containment sump concentration for post LOCA shutdown and an increase in the maximum sump pH. The maximum boron concentration is used in determining the cold leg to hot leg recirculation injection switchover time and minimum sump pH.

The accumulator pressure used in the large break LOCA analysis is a representative value of 633.5 psig. There are offsetting effects in the large break LOCA analysis relative to accumulator pressure, however the large break LOCA analysis is not particularly sensitive to initial accumulator pressure. The use of an analysis value between the minimum (600 psig) and maximum (660 psig) value is acceptable. The accumulator pressure used in the small break LOCA analysis is the minimum value of 600 psig since this is a key parameter in the analysis.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. 1 and 3).

The accumulators satisfy Criterion 3 of the NRC Policy Statement.

LCO

The LCO establishes the minimum conditions required to ensure that the accumulators are available to accomplish their core cooling safety function following a LOCA. Three accumulators are required to ensure that 100% of the contents of two of the accumulators will reach the core during a LOCA. This is consistent with the assumption that

(continued)

BASES

LCO (continued)

the contents of one accumulator spill through the break. If less than two accumulators are injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 2) could be violated.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above 1000 psig, and the limits established in the SRs for contained volume, boron concentration, and nitrogen cover pressure must be met.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure > 1000 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators provide core cooling as long as elevated RCS pressures are greater than ≤ 1000 psig and temperatures exist.

In MODE 3, with RCS pressure ≤ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated isolation valves are closed to isolate the accumulators from the RCS. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this Condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, the current analyses demonstrate that the accumulators do not discharge following a

(continued)

BASES

ACTIONS

A.1 (continued)

large main steam line break. Thus, 72 hours is allowed to return the boron concentration to within limits.

B.1 and B.2

If control power is restored to one valve identified in SR 3.5.1.5, immediate verification must be performed that no other valves listed in SR 3.5.2.1, and SR 3.5.2.7 have the control power or air restored. Additionally, Required Action B.2 requires the control power to be removed to the valve within 4 hours. In this condition, the valves could be subject to a spurious single failure that could result in closure of the valve and isolation of an accumulator. During the interval in which control power is restored, the valve remains in its required position. The 4 hour Completion Time is reasonable considering a low probability of a spurious single failure coincident with a LOCA and is consistent with the 4 hour allowed outage time for one accumulator.

C.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 4 hours. In this Condition, the required contents of two accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 4 hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions.

D.1 and D.2

If the accumulator cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

6 hours and pressurizer pressure reduced to ≤ 1000 psig within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

If more than one accumulator is inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator isolation valve should be verified to be fully open prior to removing power from the operator. This verification ensures that the accumulators are available for injection. If an isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change with power removed, a closed valve could result in not meeting accident analyses assumptions.

This Frequency is considered reasonable in view of other administrative controls that ensure a mispositioned isolation valve is unlikely.

SR 3.5.1.2 and SR 3.5.1.3

Borated water volume and nitrogen cover pressure are verified for each accumulator. The Surveillance Frequencies are controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator since the static design of the accumulators limits the ways in which the concentration can be changed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Sampling the affected accumulator within 6 hours after a ≥ 70 gallon volume increase will identify whether inleakage has caused a reduction in boron concentration. The 70 gallon volume increase and time limit of 6 hours is based on preventing a reduction in boron concentration in an accumulator below the limit as specified in the COLR assuming in-leakage of 70 gallons pure water at a maximum in-leakage rate of 0.2 gpm. It is not necessary to verify boron concentration if the added water inventory is from the refueling water storage tank (RWST), because the water contained in the RWST is within the accumulator boron concentration requirements. This is consistent with the recommendation of NUREG-1366 (Ref. 4).

SR 3.5.1.5

Verification that control power is removed from each accumulator isolation valve operator ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, only one accumulator would be available for injection given a single failure coincident with a LOCA. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR allows power to be supplied to the motor operated isolation valves when pressurizer pressure is < 1000 psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during plant startups or shutdowns.

REFERENCES

1. UFSAR, Section 6.2.1.

2. 10 CFR 50.46.

(continued)

BASES

REFERENCES (continued)

3. UFSAR, Chapter 15.

4. NUREG-1366, February 1990.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS - Operating

BASES

BACKGROUND

The function of the ECCS is to provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents:

a. Loss of coolant accident (LOCA), coolant leakage greater than the capability of the normal charging system;

b. Rod ejection accident;

c. Loss of secondary coolant accident, including uncontrolled steam release or loss of feedwater; and

d. Steam generator tube rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to significant power (Ref. 3).

There are three phases of ECCS operation: injection, cold leg recirculation, and hot leg recirculation. In the injection phase, water is taken from the refueling water storage tank (RWST) and injected into the Reactor Coolant System (RCS) through the cold legs. When sufficient water is removed from the RWST to ensure that enough boron has been added to maintain the reactor subcritical and the containment sump has enough water to supply the required net positive suction head to the ECCS pumps, suction is switched to the containment sump for cold leg recirculation. After approximately 11 hours, the ECCS flow is shifted to the hot leg recirculation phase to provide a backflush, which would reduce the boiling in the top of the core and any resulting boron precipitation.

The ECCS consists of two separate subsystems: safety injection (SI), and residual heat removal (RHR) (low head). Each subsystem consists of two redundant, 100% capacity trains. The ECCS accumulators and the RWST are also part of the ECCS, but are not considered part of an ECCS flow path

(continued)

BASES

BACKGROUND (continued)

as described by this LCO.

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the RWST can be injected into the RCS following the accidents described in this LCO. The major components of each subsystem are the RHR pumps, heat exchangers, and the SI pumps. Each of the two subsystems consists of two 100% capacity trains that are interconnected and redundant with respect to single active failures such that either train is capable of supplying 100% of the flow required to mitigate the accident consequences. This interconnecting and redundant subsystem design provides the operators with the ability to utilize components from opposite trains to achieve the required 100% flow to the core.

During the injection phase of LOCA recovery, a suction header supplies water from the RWST to the ECCS pumps. The discharge from the safety injection pumps combines prior to entering the boron injection tank (BIT) and then divides again into three supply lines, each of which feeds the injection line to one RCS cold leg. The discharge from the RHR pumps divides and feeds an injection line to each of the RCS cold legs. No credit is taken for injection header balancing. In the LOCA analyses the header of least resistance is assumed to bypass the core (Ref. 3).

For LOCAs that are too small to depressurize the RCS below the shutoff head of the SI pumps, the charging pumps supply water until the RCS pressure decreases below the SI pump shutoff head. During this period, the steam generators are used to provide part of the core cooling function.

During the recirculation phase of LOCA recovery, RHR pump suction is transferred to the containment sump. The RHR pumps then supply the other ECCS pumps. Initially, recirculation is through the same paths as the injection phase. Subsequently, recirculation supplies injection to the hot and cold legs.

The ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a main steam line break (MSLB). The limiting design conditions occur when the moderator temperature coefficient is highly negative, such as at the end of each cycle.

(continued)

BASES

BACKGROUND (continued)

During low temperature conditions in the RCS, limitations are placed on the maximum number of ECCS pumps that may be OPERABLE. Refer to the Bases for LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," for the basis of these requirements.

The ECCS subsystems are actuated upon receipt of an SI signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start immediately in the programmed sequence. If offsite power is not available, the emergency buses shed normal operating loads and are connected to the emergency diesel generators (EDGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive accumulators and the RWST covered in LCO 3.5.1, "Accumulators," and LCO 3.5.4, "Refueling Water Storage Tank (RWST)," provide the cooling water necessary to meet the HBRSEP Unit No. 2 design criteria (Ref. 1).

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 2), will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200ºF;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. Core is maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The LCO also limits the magnitude of a post trip return to power following an MSLB event and ensures that containment temperature limits are met.

Each ECCS subsystem is taken credit for in a large break LOCA event at full power (Ref. 3). This event establishes the requirement for runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The SI pumps are credited in a small break LOCA. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. A large break LOCA event, with loss of offsite power and a single failure disabling one RHR pump (both EDG trains are assumed to operate due to requirements for modeling full active containment heat removal system operation); and

b. A small break LOCA event, with a loss of offsite power and a single failure disabling one ECCS train.

Failure of a check valve in the injection pathways to open is not considered a credible single failure (Ref. 7) and therefore, the analysis does not assume a single failure of an SI cold leg injection pathway. Consequently, each ECCS injection pathway includes the flowpath to the three RCS cold legs.

During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod insertion for small breaks. Following depressurization, emergency cooling water is injected into the cold legs, flows into the downcomer, fills the lower plenum, and refloods the core.

The effects on containment mass and energy releases are accounted for in appropriate analyses (Refs. 3 and 4). The LCO ensures that an ECCS train will deliver sufficient water to match boiloff rates soon enough to minimize the consequences of the core being uncovered following a large LOCA. It also ensures that the SI pumps will deliver sufficient water and boron during a small LOCA to maintain core subcriticality. Although no credit for charging pumps are taken in LOCA analyses, for smaller LOCAs, with

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BASES

APPLICABLE SAFETY ANALYSES (continued)	break sizes ≤ 0.295 inch diameter, one charging pump delivers sufficient fluid to maintain RCS inventory; and, the steam generators continue to serve as the heat sink, providing part of the required core cooling (Ref. 3). The ECCS trains satisfy Criterion 3 of the NRC Policy Statement.
LCO	In MODES 1, 2, and 3, two redundant ECCS trains are required to ensure that sufficient ECCS flow is available, assuming a single active failure affecting either train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents. In MODES 1, 2, and 3, an ECCS train consists of an SI subsystem and an RHR subsystem. Each train includes the piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an SI signal and manually transferring suction to the containment sump. Since the failure of an ECCS cold leg injection path way check valve to open is not considered credible in the applicable safety analysis, each ECCS train includes the path ways to the three RCS cold legs. During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the ECCS pumps and their respective supply headers to each of the three cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment sump and to supply its flow to the RCS hot and cold legs. The hot leg injection paths of the safety injection system, including valves, are not subject to the requirements of this specification. The valves in the hot leg safety injection pathways are required to be closed with control power removed. In this configuration, they are not OPERABLE. Manual operator action is required to restore control power and operate the valves.
APPLICABILITY	In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are

(continued)

BASES

APPLICABILITY (continued)

based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements in the lower MODES. The SI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

Although the LCO is applicable in MODES 1, 2 and 3, the pressurizer low pressure and high steam differential pressure SI signals may be blocked when pressurizer pressure is < 2000 psig. The high steam flow coincident with low steam pressure or low average coolant temperature SI signal may be blocked when average coolant temperature is < 543ºF. These blocks facilitate plant heatup and cooldown (Ref. 4).

As indicated in Note 1, one cold leg safety injection flow path may be isolated for 24 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1.

As indicated in Note 2, operation in MODE 3 with one ECCS train declared inoperable pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is necessary with an LTOP arming temperature at or near the MODE 3 boundary temperature of 350ºF. LCO 3.4.12 requires that certain pumps be rendered inoperable at and below the LTOP arming temperature. Since this temperature is at or near the MODE 3 boundary temperature, time is needed to restore the inoperable pumps to OPERABLE status.

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

With one or more trains inoperable and at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train

(continued)

BASES

ACTIONS

A.1 (continued)

available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 5) and is a reasonable time for repair of many ECCS components.

An ECCS train is inoperable if it is not capable of delivering design flow to the RCS. Individual components are inoperable if they are not capable of performing their design function or supporting systems are not available.

The LCO requires the OPERABILITY of a number of subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one active component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different components, each in a different train, necessarily result in a loss of function for the ECCS. The intent of this Condition is to maintain a combination of equipment such that 100% of the ECCS flow equivalent to a single OPERABLE ECCS train remains available. This allows increased flexibility in plant operations under circumstances when components in opposite trains are inoperable.

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 5) has shown that the impact of having one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

Reference 6 describes situations in which one component, such as an RHR crossover valve, can disable both ECCS trains. With one or more component(s) inoperable such that 100% of the flow equivalent to a single OPERABLE ECCS train is not available, the facility is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be immediately entered.

B.1 and B.2

If control power or air is restored to one valve identified in SR 3.5.2.1 and SR 3.5.2.7, immediate verification must be performed that no other valves listed in SR 3.5.1.5 have the

(continued)

ACTIONS

B.1 and B.2 (continued)

control power restored. Additionally, Required Action B.2 requires the control power to be removed to the valve within 24 hours. In this condition, the valves could be subject to a spurious single failure that could result in closure of the valve and isolation of an accumulator. During the interval in which control power is restored, the valve remains in its required position or if a valve is repositioned after the restoration of power, the applicable condition associated with the ECCS train or flow path must be entered. The flow path to FCV-605 may be isolated in lieu of FCV-605 being in the required position. The 24 hour Completion Time is reasonable considering a low probability of a spurious single failure coincident with a LOCA.

C.1 and C.2

If the inoperable trains cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render both ECCS trains inoperable. Securing these valves in position by removal of control power or by key locking the control in the correct position ensures that they cannot change position as a result of an active failure or be inadvertently misaligned. These valves are of the type, described in Reference 6, that can disable the function of both ECCS trains and invalidate the accident analyses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve will automatically reposition within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.3

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by Section XI of the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. This ensures that pump performance is consistent with the pump curve. SRs are specified in the INSERVICE TESTING PROGRAM, which encompasses Section XI of the ASME Code. Section XI of the Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.4 and SR 3.5.2.5

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.4 and SR 3.5.2.5 (continued)

simulated SI signal and that each ECCS pump starts on receipt of an actual or simulated SI signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequencies are controlled under the Surveillance Frequency Control Program.

SR 3.5.2.6

Periodic inspections of the containment sump suction inlet ensure that it is unrestricted and stays in proper operating condition. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.7

Verification of proper valve position ensures the proper flow path is established for the LHSI system following operation in RHR mode. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.2.8

Verification of proper valve position ensures the proper flow path is established for the LHSI system following operation in RHR mode. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

REFERENCES

1. UFSAR Paragraph 3.1.2.37.
2. 10 CFR 50.46.
3. UFSAR, Chapter 15.
4. UFSAR, Chapter 6.
5. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
6. Deleted.
7. CP&L Letter to NRC, from G. E. Vaughn, "Emergency Core Cooling System (ECCS) Failure Mode and Effects Analysis (FMEA) Summary Information," May 7, 1991.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS - Shutdown

BASES

BACKGROUND

The Background section for Bases 3.5.2, "ECCS - Operating," is applicable to these Bases, with the following modifications.

In MODE 4, the required ECCS train consists of one high head safety injection (SI) subsystem and one residual heat removal (RHR) (low head) subsystem.

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the refueling water storage tank (RWST) can be injected into the Reactor Coolant System (RCS) following the accidents described in Bases 3.5.2.

WCAP-12476, Revision 1, “Evaluation of LOCA during Mode 3 and Mode 4 Operation for Westinghouse NSSS,” November 2000, provides a shutdown LOCA analysis; however, it has not been approved by the NRC and shall not be used to provide the basis for making changes under 10 CFR 50.59.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section of Bases 3.5.2 also applies to this Bases section.

Due to the stable conditions associated with operation in MODE 4 and the reduced probability of occurrence of a Design Basis Accident (DBA), the ECCS operational requirements are reduced. It is understood in these reductions that certain automatic safety injection (SI) actuation signals are not available. In this MODE, sufficient time exists for restoration and manual actuation of the required ECCS components to mitigate the consequences of a DBA.

Only one train of ECCS is required for MODE 4. This requirement dictates that single failures are not considered during this MODE of operation. The ECCS trains satisfy Criterion 3 of the NRC Policy Statement.

LCO

In MODE 4, one of the two redundant ECCS trains is required to be OPERABLE to ensure that sufficient ECCS flow is available to the core following a DBA.

(continued)

BASES (continued)

LCO
(continued)

In MODE 4, an ECCS train consists of a safety injection subsystem and an RHR subsystem aligned either for shutdown cooling or for ECCS mode. The two subsystems are not required to be from the same train (e.g., Train ‘A’ of SI and Train ‘B’ of RHR is acceptable). An ECCS train is OPERABLE when the train consists of the necessary piping, instruments and controls, valves, pumps, and heat exchangers to ensure a flow path capable of taking suction from the RWST to the SI and RHR pumps and injecting to the three RCS cold legs. The capability to transfer suction to the containment sump is also required.

While the RHR subsystem is aligned for shutdown cooling, manual alignment of the RHR subsystem would be necessary for the ECCS mode. In the long term, this flow path may be switched to hot leg injection, however; the hot leg injection paths are not subject to the requirements of this specification.

APPLICABILITY

In MODES 1, 2, and 3, the OPERABILITY requirements for ECCS are covered by LCO 3.5.2.

In MODE 4 with RCS temperature below 350EF, one OPERABLE ECCS train is acceptable without single failure consideration, on the basis of the stable reactivity of the reactor and the limited core cooling requirements.

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

A Note prohibits the application of LCO 3.0.4.b to an inoperable ECCS high head subsystem when entering MODE 4. There is an increased risk associated with entering MODE 4 from MODE 5 with an inoperable ECCS high head subsystem and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after

(continued)

BASES (continued)

APPLICABILITY (continued)

performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

ACTIONS

A.1

With no ECCS RHR subsystem OPERABLE, the plant is not prepared to respond to a loss of coolant accident or to continue a cooldown using the RHR pumps and heat exchangers. The Completion Time of immediately to initiate actions that would restore at least one ECCS RHR subsystem to OPERABLE status ensures that prompt action is taken to restore the required cooling capacity. Normally, in MODE 4, reactor decay heat is removed from the RCS by an RHR loop. If no RHR loop is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generators. The alternate means of heat removal must continue until the inoperable RHR loop components can be restored to operation so that decay heat removal is continuous.

With both RHR pumps and heat exchangers inoperable, it would be unwise to require the plant to go to MODE 5, where the only available heat removal system is the RHR. Therefore, the appropriate action is to initiate measures to restore one ECCS RHR subsystem and to continue the actions until the subsystem is restored to OPERABLE status.

B.1

With no ECCS high head subsystem OPERABLE, due to the inoperability of the safety injection train or flow path from the RWST, the plant is not prepared to provide high pressure response to Design Basis Events requiring SI. The 1 hour Completion Time to restore at least one ECCS high head subsystem to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the plant in MODE 5, where an ECCS train is not required.

C.1

When the Required Actions of Condition B cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Twenty-four hours is a reasonable time, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems or operators.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance descriptions from Bases 3.5.2 apply. This SR is modified by a Note that allows an RHR train to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the ECCS mode of operation and not otherwise inoperable. This allows operation of RHR in decay heat removal mode while in MODE 4.

REFERENCES

1. The applicable references from Bases 3.5.2 apply.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Refueling Water Storage Tank (RWST)

BASES

BACKGROUND

The RWST supplies borated water to the Chemical and Volume Control System (CVCS) during abnormal operating conditions, to the refueling pool during refueling, and to the ECCS and the Containment Spray System during accident conditions.

The RWST supplies both trains of the ECCS and the Containment Spray System supply headers during the injection phase of a loss of coolant accident (LOCA) recovery. Two motor operated isolation valves are provided to isolate the RWST from the ECCS once the system has been transferred to the recirculation mode. The recirculation mode is entered when pump suction is transferred to the containment sump following receipt of the RWST - Low Low Level signal. Use of a single RWST to supply both trains of the ECCS and Containment Spray System is acceptable since the RWST is a passive component, and passive failures are not required to be assumed.

During normal operation in MODES 1, 2, and 3, the safety injection (SI) and residual heat removal (RHR) pumps are aligned to take suction from the RWST.

The ECCS and Containment Spray System pumps are provided with recirculation lines that ensure each pump can maintain minimum flow requirements when operating at or near shutoff head conditions.

When the suction for the ECCS and Containment Spray System pumps is transferred to the containment sump, the RWST flow paths must be isolated to prevent a release of the containment sump contents to the RWST, which could result in a release of contaminants to the atmosphere and the eventual loss of suction head for the ECCS pumps.

This LCO ensures that:

a. The RWST contains sufficient borated water to support the ECCS during the injection phase;

(continued)

BASES

BACKGROUNDb (continued)

b. Sufficient water volume exists in the containment sump to support continued operation of the ECCS and Containment Spray System pumps at the time of transfer to the recirculation mode of cooling; and

c. The reactor remains subcritical following a LOCA.

Insufficient water in the RWST could result in insufficient cooling capacity when the transfer to the recirculation mode occurs. Improper boron concentrations could result in a reduction of SDM or excessive boric acid precipitation in the core following the LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment.

APPLICABLE SAFETY ANALYSES

During accident conditions, the RWST provides a source of borated water to the ECCS and Containment Spray System pumps As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Ref. 1). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "ECCS - Operating"; B 3.5.3, "ECCS - Shutdown"; and B 3.6.6, "Containment Spray and Cooling Systems." These analyses are used to assess changes to the RWST in order to evaluate their effects in relation to the acceptance limits in the analyses.

The RWST must also meet volume, boron concentration, and temperature requirements for non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the required volume is a small fraction of the available volume. The deliverable volume limit is set by the LOCA and containment analyses. For the RWST, the deliverable volume is different from the total volume contained since, due to the design of the tank, more water can be contained than can be delivered. The minimum boron concentration is an explicit assumption in the main steam line break (MSLB) analysis in order to maximize the reactivity effects of the accident. The minimum boron concentration limit is an important assumption in ensuring the required shutdown capability. The maximum boron concentration is utilized in determining the minimum time to initiate hot leg injection

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

during the recirculation phase of a LOCA response. The maximum RWST temperature is used in the containment analysis for a MSLB. The minimum RWST temperature is used in the containment analysis for inadvertent containment spray, ECCS analysis backpressure for LOCAs and reactivity analysis for a MSLB.

For a large break LOCA analysis, the minimum water volume limit of 300,000 gallons and the lower boron concentration limit specified in the COLR are used to compute the post LOCA sump boron concentration and level necessary to assure subcriticality and long term cooling capability.

The upper limit on boron concentration specified in the COLR is used to determine the maximum allowable time to switch to hot leg recirculation following a LOCA. The purpose of switching from cold leg to hot leg injection is to avoid boron precipitation in the core following the accident.

In the ECCS analysis, the containment spray temperature is assumed to be equal to the RWST lower temperature limit of 45ºF. If the lower temperature limit is violated, the containment spray further reduces containment pressure. The reduced containment pressure reduces the quality of the steam exiting the break thus decreasing the rate at which the steam is vented to the containment atmosphere. The reduction in steam vented to the containment atmosphere results in a corresponding decrease in the rate the RCS pressure drops and the rate ECCS fluid is injected into the core, thereby causing a rise in peak clad temperature. The upper temperature limit of 100ºF is used in the main steamline break containment analysis. Exceeding this temperature will result in higher containment pressures due to reduced containment spray cooling capacity. For the containment response following an MSLB, the lower limit on boron concentration and the upper limit on RWST water temperature are used to maximize the total energy release to containment.

The RWST satisfies Criterion 3 of the NRC Policy Statement.

LCO

The RWST ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover

(continued)

BASES

LCO (continued)

the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and to ensure adequate level in the containment sump to support ECCS and Containment Spray System pump operation in the recirculation mode.

To be considered OPERABLE, the RWST must meet the water volume, boron concentration, and temperature limits established in the SRs.

Aligning the Spent Fuel Pool Purification System to the RWST renders the RWST inoperable. This is due to a seismic to non-seismic interface between these systems.

APPLICABILITY

In MODES 1, 2, 3, and 4, RWST OPERABILITY requirements are dictated by ECCS and Containment Spray System OPERABILITY requirements. Since both the ECCS and the Containment Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also be OPERABLE to support their operation. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

A.1

With RWST boron concentration or borated water temperature not within limits, they must be returned to within limits within 8 hours. Under these conditions neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE condition. The 8 hour limit to restore the RWST temperature or boron concentration to within limits was developed considering the time required to change either the boron concentration or temperature and the fact that the contents of the tank are still available for injection.

B.1

With the RWST inoperable for reasons other than Condition A (e.g., water volume), it must be restored to OPERABLE status within 1 hour.

(continued)

BASES

ACTIONS

B.1 (continued)

In this Condition, neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place the plant in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains.

C.1 and C.2

If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST borated water temperature should be verified to be within the limits assumed in the accident analyses band. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

The SR is modified by a Note that eliminates the requirement to perform this Surveillance when ambient air temperatures are within the operating limits of the RWST. With ambient air temperatures within the band, the RWST temperature should not exceed the limits.

SR 3.5.4.2

The RWST water volume should be verified to be above the required minimum level in order to ensure that a sufficient initial supply is available for injection and to support continued ECCS and Containment Spray System pump

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.4.2 (continued)

operation on recirculation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.5.4.3

The boron concentration of the RWST should be verified to be within the required limits. This SR ensures that the reactor will remain subcritical following a LOCA. Further, it assures that the resulting sump pH will be maintained in an acceptable range so that boron precipitation in the core will not occur and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6 and Chapter 15.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment consists of the concrete reactor building, its steel liner, and the penetrations through this structure. The structure is designed to contain radioactive material that may be released from the reactor core following a design basis loss of coolant accident (LOCA). Additionally, this structure provides shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment is a reinforced concrete structure with a cylindrical wall, a flat foundation mat, and a shallow dome roof. The inside surface of the containment is lined with a stainless steel liner to ensure a high degree of leak tightness during operating and accident conditions.

The cylinder wall is prestressed with a post tensioning system in the vertical direction.

The concrete reactor building is required for structural integrity of the containment under Design Basis Accident (DBA) conditions. The steel liner and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 leakage rate requirements comply with 10 CFR 50, Appendix J, Option B (Ref. 1), as modified by approved exemptions.

The isolation devices for the penetrations in the containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

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

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

    2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves";

(continued)

BASES

BACKGROUND (continued)	b.	The air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Lock";
	c.	The equipment hatch is closed and sealed; and
	d.	The Isolation Valve Seal Water (IVSW) sytem is OPERABLE, except as provided in LCO 3.6.8.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a LOCA and a steam line break (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA. In the LOCA analyses, it is assumed that the containment is OPERABLE such that, for the LOCA, the release to the environment is controlled by the rate of containment leakage. The containment has an allowable leakage rate of 0.1% of containment air weight per day (Ref. 2). This leakage rate, used to evaluate offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J, Option B (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the design basis LOCA. At HBRSEP, Unit 2, P_a is specified as the containment design pressure of 42 psig. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed to be 0.1% per day in the safety analysis at P_a = 42 psig (Ref. 2).

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

Containment OPERABILITY is maintained by limiting leakage to ≤ 1.0 L_a, except prior to the first startup after performing a required Containment Leakage Rate Testing Program leakage test. At this time, the applicable leakage limits must be met.

Compliance with this LCO will ensure a containment configuration, including the equipment hatch, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analysis.

Individual leakage rates specified for the containment air lock are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the overall acceptance criteria of 1.0 L_a.

APPLICABILITY

In MODES 1, 2, 3, and 4, a LOCA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, containment is not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from containment. The requirements for containment during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

ACTIONS

A.1

In the event containment is inoperable, containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment OPERABLE during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods when containment is inoperable is minimal.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the leakage rate test requirements of the Containment Leakage Rate testing Program. Air lock leakage is not acceptable if its contribution to overall Type B, and C leakage causes overall Type B and C leakage to exceed limits. As left leakage prior to the first startup after performing a required Containment Leakage Rate testing Program leakage test is required to be, $\leq 0.60\ L_a$ for the Type B and Type C tests, and $\leq 0.75\ L_a$ for Type A tests. At all other times between required leakage rate tests, the acceptance criteria is based on an overall leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies are as required by the Containment Leakage Rate testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

> Reviewer's Note: NEI 94-01 includes acceptance criteria for as-left and as-found Type A leakage rates and combined Type B and C leakage rates, which may be reflected in the Bases.

SR 3.6.1.2

This SR ensures that the structural integrity of the containment will be maintained in accordance with the provisions of the Containment Tendon Surveillance Program.

(continued)

BASES

REFERENCES	1.	10 CFR 50, Appendix J, Option B.
	2.	UFSAR, Section 6.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Lock

BASES

BACKGROUND

The containment air lock forms part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

The air lock is nominally a right circular cylinder, 10 ft in diameter, with a door at each end. The doors are interlocked to prevent simultaneous opening. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of the air lock to remain open for extended periods when frequent containment entry is necessary. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY. Each of the doors contains double gasketed seals and local leakage rate testing capability to ensure pressure integrity. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door).

The personnel air lock is provided with limit switches on both doors that provide annunciation to the control room in the event that one airlock door is opened.

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analyses.

APPLICABLE SAFETY ANALYSES

The DBA that results in a release of radioactive material within containment is a loss of coolant accident. In the analysis of this accident, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment

(continued)

BASES

SAFETY ANALYSES (continued)

leakage. The containment has an allowable leakage rate of 0.1% of containment air weight per day at 42 psig (Ref. 2).

The containment air lock satisfies Criterion 3 of the NRC Policy Statement.

LCO

The containment air lock forms part of the containment pressure boundary. As part of containment, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

The air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in the air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

(continued)

BASES (continued)

ACTIONS

The ACTIONS are modified by a Note that allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. It is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed.

In the event the air lock leakage results in exceeding the overall containment leakage rate, Note 2 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, "Containment."

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

With one air lock door inoperable, the OPERABLE door must be verified closed (Required Action A.1). This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires containment be restored to OPERABLE status within 1 hour.

In addition, the air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is reasonable for locking the OPERABLE air lock door, considering the OPERABLE door is being maintained closed.

Required Action A.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked

(continued)

ACTIONS

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

closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls. This 7 day restriction begins when the air lock is discovered inoperable. Containment entry may be required on a periodic basis to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-required activities) if the containment is entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the containment during the short time that the OPERABLE door is expected to be open.

B.1, B.2, and B.3

With an air lock interlock mechanism inoperable, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required

(continued)

BASES

ACTIONS

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

Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

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

With the air lock inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the air lock must be restored to OPERABLE status within the 24 hour Completion Time. The specified time period is considered reasonable for restoring the

(continued)

BASES

ACTIONS

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

inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in the air lock.

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining the containment air lock OPERABLE requires compliance with the leakage rate test requirements of the Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is required by the Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria which is applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.2.2

The air lock interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and outer doors will not inadvertently occur. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. 10 CFR 50, Appendix J, Option B.

2. UFSAR, Paragraph 6.9.2.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on a containment isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Manual valves qualifying as containment isolation valves are secured closed. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System.

Automatic isolation signals are produced during accident conditions. Containment Phase "A" isolation occurs upon receipt of a safety injection signal. The Phase "A" isolation signal isolates nonessential process lines in order to minimize leakage of fission product radioactivity. Containment Phase "B" isolation occurs upon receipt of a containment pressure High-High signal and isolates the remaining process lines, except systems required for accident mitigation. In addition to the isolation signals listed above, the purge supply and exhaust valves receive an isolation signal on a containment high radiation condition. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the environment in the event of a release of fission product radioactivity to the containment atmosphere as a result of a Design Basis Accident (DBA).

(continued)

BACKGROUND (continued)

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained. The Isolation Valve Seal Water System (IVSW) assures the effectiveness of certain containment isolation valves during any condition which requires containment isolation, by providing a water seal at the valves. The requirements for the IVSW system are specified in LCO 3.6.8, "IVSW System."

Containment Purge System (42 inch purge valves)

The Containment Purge System operates to supply outside air into the containment for ventilation and cooling or heating and may also be used to reduce personnel exposure to airborne radioactive contaminants within containment prior to and during personnel access. The supply and exhaust lines each contain two isolation valves. Inboard purge supply and exhaust valves are restricted from exceeding 70 degrees open. This restriction assures proper valve closure under dynamic conditions and consequently limits offsite dose consequences resulting from a DBA which occurs when the valves are open. The 42 inch purge valves are normally maintained closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained. They may be opened during plant operation when needed for safety related reasons (both equipment and personnel) to support plant operations and maintenance activities within the containment.

Containment Pressure and Vacuum Relief Valves

The containment pressure and vacuum relief valves are provided to control variations in containment pressure with respect to atmospheric pressure which may result from air temperature changes, barometric pressure changes or air in-leakage. These valves are normally maintained closed; however, they may be opened as needed in MODES 1, 2, 3 and 4 to equalize internal and external pressure, provided that they are not open simultaneously with the containment purge valves.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the safety analyses of any event requiring isolation of containment is applicable to this LCO.

The DBA that results in a release of radioactive material within containment is a loss of coolant accident (LOCA) (Ref. 1). In the analyses for each of these accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves (including containment purge valves) are minimized.

Isolation of containment ventilation isolation valves is complete within approximately two seconds following generation of the phase A containment isolation signal. Isolation of the remaining containment isolation valves is complete within approximately ten seconds following generation of either the phase A or phase B containment isolation signal. Upon completion of containment isolation, leakage is terminated except for the design leakage rate, L_a.

The single failure criterion required to be imposed in the conduct of plant safety analyses was considered in the original design of the containment purge valves. Two valves in series on each purge line provide assurance that both the supply and exhaust lines could be isolated even if a single active failure occurred. The inboard and outboard isolation valves on each line are provided with air-cylinder operators, with spring assisted closure capable of closing valves in two seconds. These valves fail to the closed position on a loss of a control signal or instrument air. This arrangement was designed to preclude common mode failures from disabling both valves on a purge line.

The containment isolation valves satisfy Criterion 3 of the NRC Policy Statement.

(continued)

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valves' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The inboard 42 inch purge valves must have blocks installed to prevent full opening and actuate closed on an automatic signal. The valves covered by this LCO are listed along with their associated stroke times in the INSERVICE TESTING PROGRAM.

The normally closed isolation valves are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, or blind flanges are in place.

This LCO provides assurance that the containment isolation valves and purge valves will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE in MODE 5. The requirements for containment isolation valves during MODE 6 are addressed in LCO 3.9.4, "Containment Penetrations."

ACTIONS

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

(continued)

ACTIONS (continued)

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

The ACTIONS are further modified by a third Note, which ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation valve.

In the event the isolation valve leakage results in exceeding the overall containment leakage rate, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1. In the event required IVSW supply is isolated to a penetration flowpath, Note 5 directs entry into applicable Conditions and Required Actions of LCO 3.6.8.

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths is inoperable, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4. For some penetration flowpaths supplied by IVSW, an inoperable isolation valve may prevent

(continued)

ACTIONS

A.1 and A.2 (continued)

the IVSW system from providing a water seal. Although not directly comparable to leak rate testing performed in accordance with 10 CFR 50, Appendix J, the hydrostatic testing of the IVSW headers specified in SR 3.6.8.6 provides a means of verifying that leakage through the IVSW supplied isolation valves is limited. The four hour Completion Time to isolate the penetration is acceptable based upon consideration of the time required to isolate the flowpath, the limited leakage potential for the isolation valve and the low probability of an event requiring containment isolation during the specified time period to isolate the flowpath.

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification, through a system walkdown, that those isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two containment isolation valves. For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides the appropriate actions

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(continued)

ACTIONS

A.1 and A.2 (continued)

Required Action A.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these devices once they have been verified to be in the proper position, is small.

B.1

With two containment isolation valves inoperable in one or more penetration flow paths with two isolation valves, the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1. In the event the affected penetration is isolated in accordance with Required Action B.1, the affected penetration must be verified to be isolated on a periodic basis per Required Action A.2, which remains in effect. This periodic verification is necessary to assure leak tightness of containment and that penetrations requiring isolation following an accident are isolated. The Completion Time of "once per 31 days for isolation devices outside containment" for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative control and the probability of their misalignment is low.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two containment isolation valves. Condition A of this LCO addresses the condition of one containment isolation valve inoperable in this type of penetration flow path.

(continued)

ACTIONS (continued)

C.1 and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve flow path must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The device used to isolate the flow path should be the one closest available to containment. A check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of "once per 31 days for isolation devices outside containment" for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve and a closed system. The closed system must meet the requirements of Ref. 3. This Note is necessary since this Condition is written to specifically address those penetration flow paths

(continued)

ACTIONS

C.1 and C.2 (continued)

in a closed system. In some instances penetration flow paths connected to closed systems contain more than one containment isolation valve. The inoperability of one of these valves does not render the containment penetration flow path inoperable if the remaining containment isolation valve(s) is operable and the closed system is intact.

Required Action C.2 is modified by a Note that applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

D.1 and D.2

If the Required Actions and associated Completion Times are not met or if the 42 inch penetration (supply or exhaust) purge valves are open and the 6 inch penetration (pressure or vacuum relief) valves are open simultaneously, 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 3.6.3.1

This SR ensures that the 42 inch purge supply and exhaust valves and 6 inch pressure and vacuum relief valves are closed as required or, if open, open for an allowable reason. If a valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is not required to be met when the valves are open for

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1 (continued)

safety related considerations (equipment or personnel) to support plant operations and maintenance activities within containment. Examples of this may include operating the valves to reduce activity to increase stay times, eliminate the need for respiratory protective equipment, reduce ambient temperatures during hot months, to increase the effectiveness of workers and to minimize occupational effects of necessary, non-routine activities in containment, or for Surveillances that require the valves to be open. The valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. Since it is not operationally necessary, it is desirable to preclude the 42 inch valves and 6 inch valves from being open at the same time. A Note to this SR restricts the 6 inch and 42 inch valves from being open simultaneously.

SR 3.6.3.2

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those containment isolation valves outside containment and capable of being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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SURVEILLANCE REQUIREMENTS

SR 3.6.3.2 (continued)

The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing or securing.

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3 and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing or securing.

This Note allows valves and blind flanges located in high radiation areas to be verified closed by use of

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SURVEILLANCE REQUIREMENTS

SR 3.6.3.3 (continued)

administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4, for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position, is small.

SR 3.6.3.4

Verifying that the isolation time of each automatic power operated containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The isolation time and Frequency of this SR are in accordance with the Inservice Testing (IST) Program. In addition to the INSERVICE TESTING PROGRAM testing frequency, the 42 inch purge supply and exhaust valves will be tested prior to use if not tested within the previous quarter. Otherwise, the 42 inch purge supply and exhaust valves are not cycled quarterly only for testing purposes.

SR 3.6.3.5

Automatic containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.3.6

Verifying that each 42 inch inboard containment purge valve is blocked to restrict opening to ≤ 70º is required to ensure that the valves can close under DBA conditions within the times assumed in the analyses of References 1 and 2. If a LOCA occurs, the purge valves must close to maintain containment leakage within the values assumed in the accident analysis. At other times when purge valves are required to be capable of closing (e.g., during movement of irradiated fuel assemblies), pressurization concerns are not present, thus the purge valves can be fully open. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 15.
2. UFSAR, Section 6.2.
3. Standard Review Plan 6.2.4.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). These limits also prevent the containment pressure from exceeding the containment design negative pressure differential with respect to the outside atmosphere in the event of inadvertent actuation of the Containment Spray System.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The initial pressure condition used in the containment analysis was 15.7 psia (1.0 psig) The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer codes designed to predict the resultant pressure and temperature transient. The containment pressure analysis indicates the containment peak pressure for the limiting SLB slightly exceeds the peak pressure for the limiting LOCA (Ref. 1) and does not exceed the containment design pressure, 42 psig.

The containment was also designed for an external pressure load equivalent to -3.0 psig. The inadvertent actuation of the Containment Spray System was analyzed to determine

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the resulting reduction in containment pressure. The initial pressure condition used in this analysis was -0.8 psig. This resulted in a minimum pressure inside containment of -3.0 psig, which does not exceed the design load.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. Therefore, for the reflood phase, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50, Appendix K (Ref. 2).

Containment pressure satisfies Criterion 2 of the NRC Policy Statement.

LCO

Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit ensures that the containment will not exceed the design negative differential pressure following the inadvertent actuation of the Containment Spray System.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analyses are maintained, the LCO is applicable in MODES 1, 2, 3 and 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODE 5 or 6.

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(continued)

BASES (continued)

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, it must be restored to within these limits within 1 hour. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If containment pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that containment pressure is within limits ensures that unit operation remains within the limits assumed in the containment analysis. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 6.2.

2. 10 CFR 50, Appendix K.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Air Temperature

BASES

BACKGROUND

The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment average air temperature is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB).

The containment average air temperature limit is derived from the input conditions used in the containment functional analyses and the containment structure external pressure analyses. This LCO ensures that initial conditions assumed in the analysis of containment response to a DBA are not violated during unit operations. The total amount of energy to be removed from containment by the Containment Spray and Cooling systems during post accident conditions is dependent upon the energy released to the containment due to the event, as well as the initial containment temperature and pressure. The higher the initial temperature, the more energy that must be removed, resulting in higher peak containment pressure and temperature. Exceeding containment design pressure may result in leakage greater than that assumed in the accident analysis. Operation with containment temperature in excess of the LCO limit violates an initial condition assumed in the accident analysis.

APPLICABLE SAFETY ANALYSES

Containment average air temperature is an initial condition used in the DBA analyses that establishes the containment environmental qualification operating envelope for both pressure and temperature. The limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analyses for containment (Ref. 1).

The limiting DBAs considered relative to containment OPERABILITY are the LOCA and SLB. The DBA LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to Engineered Safety Feature (ESF) systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train each of the Containment Spray System, Residual Heat Removal System, and Containment Cooling System being rendered inoperable.

The limiting DBA for the maximum peak containment air temperature is an SLB. The initial containment average air temperature assumed in the design basis analyses (Ref. 1) is 130ºF. This resulted in a maximum containment air temperature of approximately 322.6ºF. The maximum containment air temperature from a LOCA is approximately 265.8ºF. The environmental qualification temperature limit bounds the maximum SLB and LOCA temperature responses. The containment structural design temperature is 263°F.

The temperature limit is used to establish the environmental qualification operating envelope for containment. The maximum peak containment air temperature was calculated to exceed the containment design temperature briefly during the transient. The basis of the containment design temperature, however, is to ensure the performance of safety related equipment inside containment (Ref. 2). Thermal analyses showed that the time interval during which the containment air temperature exceeded the containment design temperature was short enough that the equipment surface temperatures remained below the design temperature. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBA SLB.

The temperature limit is also used in the depressurization analyses to ensure that the minimum pressure limit is maintained following an inadvertent actuation of the Containment Spray System (Ref. 1).

The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure is a LOCA. The temperature limit is used in this analysis to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Containment average air temperature satisfies Criterion 2 of the NRC Policy Statement.
LCO	During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature is maintained below the values previously analyzed. As a result, the ability of containment to perform its design function is ensured.
APPLICABILITY	In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODE 5 or 6.

ACTIONS

A.1

When containment average air temperature is not within the limit of the LCO, it must be restored to within limit within 8 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems.

B.1 and B.2

If the containment average air temperature cannot be restored to within its limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	<u>SR 3.6.5.1</u> Verifying that containment average air temperature is within the LCO limit ensures that containment operation remains within the limit assumed for the containment analyses. In order to determine the containment average air temperature, a volumetric average is calculated using measurements taken at locations within the containment selected to provide a representative sample of the overall containment atmosphere. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 6.2. 2. 10 CFR 50.49.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray and Cooling Systems

BASES

BACKGROUND

The Containment Spray and Containment Cooling systems provide containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine removal capability of the spray reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA), to within limits. The Containment Spray and Containment Cooling systems are designed to meet the requirements of HBRSEP Design Criteria (Ref. 1).

The Containment Cooling System and Containment Spray System are Engineered Safety Feature (ESF) systems. They are designed to ensure that the heat removal capability required during the post accident period can be attained. The Containment Spray System and the Containment Cooling System provide redundant methods to limit and maintain post accident conditions to less than the containment design values.

Containment Spray System

The Containment Spray System consists of two separate trains of equal capacity, each capable of meeting the design bases. Each train includes a containment spray pump, spray headers, nozzles, valves, and piping. Each train is powered from a separate ESF bus. The refueling water storage tank (RWST) supplies borated water to the Containment Spray System during the injection phase of operation. In the recirculation mode of operation, containment spray pump suction is transferred from the RWST to the containment sump(s).

The Containment Spray System provides a spray of cold borated water mixed with sodium hydroxide (NaOH) from the spray additive tank into the upper regions of containment to reduce the containment pressure and temperature and to reduce fission products from the containment atmosphere during a DBA. The RWST solution temperature is an important factor in determining the heat removal capability of the

(continued)

BACKGROUND

Containment Spray System (continued)

Containment Spray System during the injection phase. In the recirculation mode of operation, heat is removed from the containment sump water by the residual heat removal coolers. Each train of the Containment Spray System provides adequate spray coverage to meet the system design requirements for containment heat removal.

The Spray Additive System injects an NaOH solution into the spray. The resulting alkaline pH of the spray enhances the ability of the spray to scavenge fission products from the containment atmosphere. The NaOH added in the spray also ensures an alkaline pH for the solution recirculated in the containment sump. The alkaline pH of the containment sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

The Containment Spray System is actuated either automatically by a containment High - High pressure signal or manually. An automatic actuation opens the containment spray pump discharge valves, starts the two containment spray pumps, and begins the injection phase. A manual actuation of the Containment Spray System requires the operator to actuate two separate switches on the main control board to begin the same sequence. The injection phase continues until an RWST level Low alarm is received. The Low level alarm for the RWST signals the operator to manually align the system to the recirculation mode. The Containment Spray System in the recirculation mode maintains an equilibrium temperature between the containment atmosphere and the recirculated sump water. Operation of the Containment Spray System in the recirculation mode is controlled by the operator in accordance with the emergency operating procedures.

Containment Cooling System

Two trains of containment cooling, each of sufficient capacity to supply 100% of the design cooling requirement, are provided. Each train of two fan units is supplied with cooling water from a separate train of service water (SW). Air is drawn into the coolers through the fan and discharged to the reactor coolant pump bays, pressurizer compartment,

(continued)

BASES

BACKGROUND

Containment Cooling System (continued)

and incore detector raceway, and outside the secondary shield in the lower areas of containment.

During normal operation, all four fan units may be operating. The fans are normally operated with SW supplied to the cooling coils. The Containment Cooling System, operating in conjunction with the Containment Ventilation system, is designed to limit the ambient containment air temperature during normal unit operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

In post accident operation following an actuation signal, the Containment Cooling System fans are designed to start automatically if not already running. The temperature of the SW is an important factor in the heat removal capability of the fan units.

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Cooling System limit the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF systems, assuming the loss of one ESF bus, which is the worst case single active failure and results in one train of the Containment Spray System and Containment Cooling System being rendered inoperable.

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure is 41.8 psig (experienced during a LOCA). The analysis shows that the peak containment temperature is approximately 322.6ºF (experienced during an SLB). Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion.) The limiting SLB analysis for pressure response assumes a power level of 0% with the single failure of an emergency bus. The limiting analysis for temperature response assumes a SLB with a power level of 0% and a single failure of a steam line check valve. The limiting pressure response

(continued)

APPLICABLE SAFETY ANALYSES (continued)

is the Double Ended Pump Suction (DEPS) LOCA with minimum safety injection. The analyses assume the limiting initial conditions for pressure (-0.8 to 1.0 psig) and temperature (75 F to 130 F) as applicable. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures in accordance with 10 CFR 50, Appendix K (Ref. 2).

The effect of an inadvertent containment spray actuation has been analyzed. An inadvertent spray actuation is limited to a -3.0 psig containment pressure and is associated with the sudden cooling effect in the interior of the leak tight containment. Additional discussion is provided in the Bases for LCO 3.6.4.

The modeled Containment Spray System actuation from the containment analysis is based on a response time associated with exceeding the containment High - High pressure setpoint to achieving full flow through the containment spray nozzles.

Containment cooling train performance for post accident conditions is given in Reference 3. The result of the analysis is that each train can provide 100% of the required peak cooling capacity during the post accident condition. The train post accident cooling capacity under varying containment ambient conditions, is also shown in Reference 4. The modeled Containment Cooling System actuation from the containment analysis is based on a response time associated with exceeding the containment high pressure setpoint to achieving full Containment Cooling System air and cooling water flow.

The Containment Spray System and the Containment Cooling System satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES (continued)

LCO

During a DBA, a minimum of one containment cooling train and one containment spray train are required to maintain the containment peak pressure and temperature below the design limits (Ref. 3). Additionally, one containment spray train is also required to remove iodine from the containment atmosphere and maintain concentrations below those assumed in the safety analysis. To ensure that these requirements are met, two containment spray trains and two containment cooling trains must be OPERABLE. Therefore, in the event of an accident, at least one train in each system operates, assuming the worst case single active failure occurs.

Each Containment Spray System typically includes a spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal and transferring suction to the containment sump.

Each Containment Cooling System typically includes cooling coils, dampers, fans, instruments, and controls to ensure an OPERABLE flow path.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature requiring the operation of the containment spray trains and containment cooling trains.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the Containment Spray System and Containment Cooling Systems are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one containment spray train inoperable, the inoperable containment spray train must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE spray and cooling trains are adequate to perform the iodine removal and containment cooling functions. The 72 hour Completion Time takes into account the redundant heat

(continued)

BASES

ACTIONS

A.1 (continued)

removal capability afforded by the Containment Spray System and Containment Cooling System, reasonable time for repairs, and low probability of a DBA occurring during this period.

The 10 day portion of the Completion Time for Required Action A.1 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this Specification coupled with the low probability of an accident occurring during this time. Refer to Section 1.3, "Completion Times," for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

B.1 and B.2

If the inoperable containment spray train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows additional time for attempting restoration of the containment spray train and is reasonable when considering the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

C.1

With one of the containment cooling trains inoperable, the inoperable containment cooling train must be restored to OPERABLE status within 7 days. In this degraded condition at least one train of containment spray and the remaining containment cooling train are capable of providing at least 100% of the heat removal needs. The 7 day Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray System and

(continued)

BASES

ACTIONS

C.1 (continued)

Containment Cooling System and the low probability of DBA occurring during this period.

The 10 day portion of the Completion Time for Required Action C.1 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this Specification coupled with the low probability of an accident occurring during this time. Refer to Section 1.3 for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

D.1

With two containment cooling trains inoperable, one of the containment cooling trains must be restored to OPERABLE status within 72 hours. In this degraded condition the containment spray trains are capable of providing at least 100% of the heat removal needs after an accident. The 72 hour Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray System and Containment Cooling System, the iodine removal function of the Containment Spray System, and the low probability of DBA occurring during this period.

E.1 and E.2

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

(continued)

BASES

ACTIONS (continued)

F.1

With two containment spray trains or any combination of three or more containment spray and cooling trains inoperable, the unit is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power operated, and automatic valves in the containment spray flow path provides assurance that the proper flow paths will exist for Containment Spray System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned are in the correct position. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.2

Operating each containment cooling train fan unit for ≥ 15 minutes ensures that all trains are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.3

Verifying that each containment cooling SW cooling flow rate to each cooling unit is ≥ 750 gpm provides assurance that the design flow rate assumed in the safety analyses will be achieved (Ref. 4). The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.4

Verifying each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by Section XI of the ASME Code (Ref. 5). Since the containment spray pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow. This test confirms pump performance is consistent with the pump design curve and is indicative of overall performance, by setting the pump head and measuring the test flow. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of the SR is in accordance with the INSERVICE TESTING PROGRAM.

SR 3.6.6.5 and SR 3.6.6.6

These SRs require verification that each automatic containment spray valve actuates to its correct position and that each containment spray pump starts upon receipt of an actual or simulated actuation of a containment High - High pressure signal. SR 3.6.6.5 is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. SR 3.6.6.6 must be performed with the isolation valves in the spray supply lines at the containment and spray additive tank locked closed. The Surveillance Frequencies are controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.7

This SR requires verification that each containment cooling train actuates upon receipt of an actual or simulated safety injection signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.6.8

With the containment spray inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through test connections. This SR ensures that each spray nozzle is unobstructed and provides assurance that spray coverage of the containment during an accident is not degraded. Performance is required following activities which could result in nozzle blockage. Such activities may include: (1) a major configuration change; or (2) a loss of foreign material control such that the final condition of the system cannot be assured. The frequency is considered adequate due to the passive design of the nozzles, the stainless steel construction of the piping and nozzles, and the use of foreign material exclusion controls during system opening.

REFERENCES

1. UFSAR, Section 3.1.
2. 10 CFR 50, Appendix K.
3. UFSAR, Section 6.2.
4. UFSAR, Section 9.4.
5. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Spray Additive System

BASES

BACKGROUND

The Spray Additive System is a subsystem of the Containment Spray System that assists in reducing the iodine fission product inventory in the containment atmosphere resulting from a Design Basis Accident (DBA).

Radioiodine in its various forms is the fission product of primary concern in the evaluation of a DBA. It is absorbed by the spray from the containment atmosphere. To enhance the iodine absorption capacity of the spray, the spray solution is adjusted to an alkaline pH that promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms. Because of its stability when exposed to radiation and elevated temperature, sodium hydroxide (NaOH) is the preferred spray additive. The NaOH added to the spray also ensures a pH value of between 8.5 and 11.0 of the solution recirculated from the containment sump. This pH band minimizes the evolution of iodine as well as the occurrence of chloride and caustic stress corrosion on mechanical systems and components.

<u>Eductor Feed System</u>

The Spray Additive System consists of one spray additive tank that is shared by the two trains of spray additive equipment. Each train of equipment provides a flow path from the spray additive tank to a containment spray pump and consists of an eductor for each containment spray pump, valves, instrumentation, and connecting piping. Each train of the Spray Additive System is not totally independent of the other train. Certain passive components (tank, piping, etc.) as well as redundant active components (valves) are shared by both trains. Depending upon which component is affected, the complete Spray Additive System may be inoperable or only one train may be inoperable. Each eductor draws the NaOH spray solution from the common tank using a portion of the borated water discharged by the containment spray pump as the motive flow. The eductor mixes the NaOH solution and the borated water and discharges the mixture into the spray pump suction line. The educators

(continued)

BASES

BACKGROUND (continued)

are designed to ensure that the pH of the spray mixture is between 8.8 and 10.0 during the injection phase.

APPLICABLE SAFETY ANALYSES

The Spray Additive System is essential to the removal of airborne iodine within containment following a DBA.

Following the assumed release of radioactive materials into containment, the containment is assumed to leak at its design value volume following the accident. The analysis assumes that containment is adequately covered by the spray (Ref. 1).

The DBA response time assumed for the Spray Additive System is the same as for the Containment Spray System and is discussed in the Bases for LCO 3.6.6, "Containment Spray and Cooling Systems."

The DBA analyses assume that one train of the Containment Spray System/Spray Additive System is inoperable and that the entire spray additive tank volume is added to the remaining Containment Spray System flow path.

The Spray Additive System satisfies Criterion 3 of the NRC Policy Statement.

LCO

The Spray Additive System is necessary to reduce the release of radioactive material to the environment in the event of a DBA. To be considered OPERABLE, the volume and concentration of the spray additive solution must be sufficient to provide NaOH injection into the spray flow until the Containment Spray System suction path is switched from the refueling water storage tank (RWST) to the containment sump, and to raise the average spray solution pH to a level conducive to iodine removal, namely, to between 8.5 and 11.0. This pH range maximizes the effectiveness of the iodine removal mechanism without introducing conditions that may induce caustic stress corrosion cracking of mechanical system components. For a train of the Spray Additive System to be considered Operable, it must be capable of supplying its train's Spray Additive System flow to its associated Containment Spray System train. In addition, it is essential that valves in

(continued)

BASES

LCO (continued)

the Spray Additive System flow paths are properly positioned and that automatic valves are capable of activating to their correct positions.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment requiring the operation of the Spray Additive System. The Spray Additive System assists in reducing the iodine fission product inventory prior to release to the environment.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Thus, the Spray Additive System is not required to be OPERABLE in MODE 5 or 6.

ACTIONS

A.1

If one Spray Additive System train is inoperable and at least 100% of the Spray Additive System flow equivalent to an OPERABLE Spray Additive System train is available to an OPERABLE Containment Spray train, it must be restored to OPERABLE within 72 hours. With one train of the Containment Spray Additive System inoperable, the remaining train is capable of supplying its flow to the associated Containment Spray System train. This circumstance is bounded by the inoperablility of a Containment Spray Train. In this condition the redundant train of the Spray Additive System in conjunction with the associated Containment Spray Train provides iodine removal capability consistent with the assumptions in the accident analysis.

B.1

If the Spray Additive System is inoperable for reasons other than Condition A, one train must be restored to OPERABLE status within 1 hour. The pH adjustment of the Containment Spray System flow for corrosion protection and iodine removal enhancement is reduced in this condition. The Containment Spray System would still be available and would remove some iodine from the containment atmosphere in the event of a DBA. The 1 hour Completion Time takes into

(continued)

BASES

ACTIONS

B.1 (continued)

account the time necessary to restore the System to Operable Status, the relative importance of pH adjustment of the Containment Spray System flow for corrosion protection and iodine removal as well as the low probability of the worst case DBA occurring during this period.

C.1 and C.2

If the Spray Additive System cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows 48 hours for restoration of the Spray Additive System in MODE 3 and 36 hours to reach MODE 5. This is reasonable when considering the reduced pressure and temperature conditions in MODE 3 for the release of radioactive material from the Reactor Coolant System.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Verifying the correct alignment of Spray Additive System manual, power operated, and automatic valves in the spray additive flow path provides assurance that the system is able to provide additive to the Containment Spray System in the event of a DBA. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.7.2

To provide effective iodine removal, the containment spray must be an alkaline solution. Since the RWST contents are normally acidic, the volume of the spray additive tank must provide a sufficient volume of spray additive to adjust pH for all water injected. This SR is performed to verify the availability of sufficient NaOH solution in the Spray Additive System. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.3

This SR provides verification of the NaOH concentration in the spray additive tank and is sufficient to ensure that the spray solution being injected into containment is at the correct pH level. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.7.4

This SR provides verification that each automatic valve in the Spray Additive System flow path actuates to its correct position. 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 controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES 1. UFSAR, Chapter 6.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Isolation Valve Seal Water (IVSW) System

BASES

BACKGROUND

The Isolation Valve Seal Water (IVSW) System assures the effectiveness of certain containment isolation valves during any condition which requires containment isolation, by providing a water seal at the valves. These valves are located in lines that are connected to the Reactor Coolant System (RCS), or that could be exposed to the containment atmosphere in the event of a loss of coolant accident (LOCA). The system provides a reliable means for injecting seal water between the seats and stem packing of the globe and double disc types of isolation valves, and into the piping between other closed isolation valves. The system provides assurance that, should an accident occur, the containment leak rate is no greater than that assumed in the accident analysis by providing seal water at a pressure ≥ 1.1 times P_a. The system is designed to maintain this seal for at least 30 days. The possibility of leakage from the containment or RCS past the first isolation point is thereby prevented by assuring that if leakage does exist, it will be from the IVSW System into containment.

The system includes one 175 gallon seal water tank capable of supplying the total requirements of the system. The IVSW tank's required volume is maintained and the tank is pressurized with nitrogen. The normal supply of makeup water to the IVSW tank is the Primary Water System. In the event Primary Water is not available, emergency makeup can be supplied from the Service Water System. The Plant Nitrogen System provides the normal supply of nitrogen to the IVSW tank. An automatic backup supply is provided from two dedicated high pressure nitrogen bottles (Ref. 1).

The system is normally in a static condition with the seal water injection tank filled and pressurized. Indication of IVSW tank level and pressure along with corresponding low level and low pressure alarms are provided in the Control Room. The tank supplies pressurized water to four distribution headers. Header "A" requires manual operation and serves lines that are normally filled with fluid following a LOCA, and lines that must remain in service for

(continued)

BASES

BACKGROUND (continued)	a period of time following the accident. Headers "B", "C", and "D" are automatic headers that are pressurized through one or both of two redundant, fail open, air operated valves arranged in parallel. A loss of power will cause these valves to fail open. System operation is initiated by a Phase A containment isolation signal which accompanies any Safety Injection (SI) signal.
APPLICABLE SAFETY ANALYSES	The Design Basis Accident (DBA) that results in a release of radioactive material within containment is a loss of coolant accident (LOCA). The analyses for the LOCA assumes the isolation of containment is completed and leakage from containment is at a rate equivalent to the design leakage rate. As part of the containment boundary, containment isolation valves function to support the leak tightness of containment. By maintaining this barrier, offsite dose calculations will be less than the limits of 10 CFR 100 or 10 CFR 50.67, as applicable, during a DBA (Ref. 2). The IVSW System actuates on a containment isolation signal and functions to assure the actual leakage is no greater than the design value. IVSW assures the effectiveness of certain isolation valves to limit containment leakage by pressurizing the affected containment penetration flow paths at a pressure ≥ 1.1 times P_a. IVSW is designed to maintain this seal for at least 30 days. A single failure analysis shows the failure of any active component will not prevent fulfilling the design function of the system. By meeting these requirements, IVSW is considered a qualified seal system in accordance with 10 CFR 50, Appendix J (Ref. 3). The Isolation Valve Seal Water System satisfies Criterion 3 of the NRC Policy Statement.
LCO	During the DBA, the IVSW System must function to seal the associated penetration flow paths. OPERABILITY of the IVSW System is based on the its ability to seal selected containment penetration flow paths, at elevated pressure for at least 30 days assuming a single active failure. This requires that the IVSW tank be maintained with an adequate volume of water at sufficient pressure to provide the motive

(continued)

BASES

LCO (continued)

force necessary to move this fluid to the applicable penetration. Piping as well as redundant active components (regulators and valves) necessary to provide a system capable of sustaining a single active failure are required to be OPERABLE. Automatic makeup from the dedicated nitrogen bottles and manual capability for makeup from both the Service Water System and the Primary Water System is required for the IVSW System to be OPERABLE.

APPLICABILITY

In MODES 1, 2, 3 and 4, a DBA could cause a release of radioactive material to containment. Therefore, the IVSW System is required to be OPERABLE in MODES 1, 2, 3 and 4 to prevent leakage from containment. IVSW is not required to be OPERABLE in MODES 5 and 6, since the probability and consequences of these events are reduced due to the pressure and temperature limitations applicable to these MODES.

ACTIONS

A.1

With the IVSW System inoperable, the system must be restored to OPERABLE status within 72 hours. The 72 hour completion time is reasonable considering the time necessary to repair most components and the low probability of an event which would require the IVSW System to function.

Without the benefit of the IVSW System the effectiveness of certain containment isolation valves to limit the containment leakage rate following a DBA is reduced. The containment is designed with an allowable leakage rate not to exceed 0.1% of the containment volume per day. The maximum allowable leakage rate is used to evaluate offsite doses resulting from a DBA. Confirmation that the leakage rate is within limit is demonstrated by the performance of a Type A leakage rate test in accordance with the Containment Leakage Rate Testing Program as required by LCO 3.6.1, "Containment." During the performance of the Type A test no credit is taken for the IVSW System in meeting the containment leakage rate criteria. As such, in the event of a DBA without an OPERABLE IVSW System, both the whole body and thyroid offsite doses would be within the limits specified in 10 CFR Part 50.67.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1

This SR verifies the IVSW tank has the necessary pressure to provide motive force to the seal water. A pressure ≥ 46.2 psig ensures the containment penetration flowpaths that are sealed by the IVSW System are maintained at a pressure which is at least 1.1 times the calculated peak containment internal pressure (P_a) related to the design bases accident. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.8.2

This SR verifies the IVSW tank has an initial volume of water necessary to provide seal water to the containment isolation valves served by the IVSW System. An initial volume ≥ 85 gallons ensures the IVSW System contains the proper inventory to maintain the required seal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.8.3

This SR verifies the stroke time of each automatic air operated header injection solenoid valve is within limits. The frequency is specified by the INSERVICE TESTING PROGRAM,

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.8.3 (continued)

and previous operating experience has shown that these valves usually pass the required test when performed.

SR 3.6.8.4

This SR ensures that automatic header injection valves actuate to the correct position on a simulated or actual signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.8.5

This SR ensures the capability of the dedicated nitrogen bottles to pressurize the IVSW system independent of the Plant Nitrogen System. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.6.8.6

Integrity of the IVSW seal boundary is important in providing assurance that the design leakage value required for the system to perform its sealing function is not exceeded. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 6.8.

2. UFSAR, Chapter 15.

3. A. Schwencer (NRC) letter to CP&L dated 4/23/79, Response to 3/15/79 letter regarding the acceptability of the IVSW system.

B 3.7 PLANT SYSTEMS

B 3.7.1 Main Steam Safety Valves (MSSVs)

BASES

BACKGROUND

The primary purpose of the MSSVs is to provide overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the reactor coolant pressure boundary (RCPB) by providing a heat sink for the removal of energy from the Reactor Coolant System (RCS) if the preferred heat sink, provided by the Condenser and Circulating Water System, is not available.

Four MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves, as described in the UFSAR, Section 10.3.2 (Ref. 1). The MSSVs must have sufficient capacity to limit the secondary system pressure to ≤ 110% of the steam generator design pressure in order to meet the requirements of the ASME Code, Section III (Ref. 2). The MSSV design includes staggered setpoints, according to Table 3.7.1-2 in the accompanying LCO, so that only the needed valves will actuate. Staggered setpoints reduce the potential for valve chattering that is due to steam pressure insufficient to fully open all valves following a turbine or reactor trip.

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from Reference 2 and its purpose is to limit the secondary system pressure to ≤ 110% of design pressure for any anticipated operational occurrence (AOO) or accident considered in the design basis accident (DBA) and transient analysis.

The events that challenge the relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased heat removal events, which are presented in the UFSAR, Section 15.2 (Ref. 3). Of these, the loss of external electrical load is the limiting AOO.

The safety analysis presented in UFSAR Section 15.2.2 (Ref. 3) demonstrates that the transient response for loss of external electrical load occurring from full power presents no hazard to the integrity of the RCS or the Main Steam System.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

All cases analyzed demonstrate that the MSSVs maintain Main Steam System integrity by limiting the maximum steam pressure to less than 110% of the steam generator design pressure.

In addition to the decreased heat removal events, reactivity insertion events may also challenge the relieving capacity of the MSSVs. The uncontrolled rod cluster control assembly (RCCA) bank withdrawal at power event is characterized by an increase in core power and steam generation rate until reactor trip occurs when the Overtemperature ΔT, Overpower ΔT, high pressurizer pressure, or Power Range Neutron Flux-High setpoint is reached. Steam flow to the turbine may increase from its initial value for this event. The increased heat transfer to the secondary side causes an increase in steam pressure and may result in opening of the MSSVs prior to the reactor trip, depending on the operation of the atmospheric or condenser steam dump valves. The safety analysis of the RCCA bank withdrawal at power event for a range of initial core power levels demonstrates that the MSSVs are capable of preventing secondary side overpressurization for this AOO.

The UFSAR safety analyses discussed above assume that all of the MSSVs for each steam generator are OPERABLE. If there are inoperable MSSV(s), it is necessary to limit the primary system power during steady state operation and AOOs to a value that does not result in exceeding the combined steam flow capacity of the turbine (if available) and the remaining OPERABLE MSSVs. The required limitation on primary system power necessary to prevent secondary system overpressurization is conservatively arrived at by a simple heat balance calculation. In some circumstances it is necessary to limit the primary side heat generation that can be achieved during an AOO by reducing the setpoint of the Power Range Neutron Flux-High reactor trip function. For example, if more than one MSSV on a single steam generator is inoperable, an uncontrolled RCCA bank withdrawal at power

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

event occurring from a partial power level may result in an increase in reactor power that exceeds the combined steam flow capacity of the turbine and the remaining OPERABLE MSSVs. Thus, for multiple inoperable MSSVs on the same steam generator it is necessary to prevent this power increase by lowering the Power Range Neutron Flux-High setpoint to an appropriate value. When the Moderator Temperature Coefficient (MTC) is positive, the reactor power may increase above the initial value during an RCS heatup event (e.g., turbine trip). Thus, for any number of inoperable MSSVs it is necessary to reduce the trip setpoint if a positive MTC may exist at partial power conditions.

The MSSVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

The accident analysis assumes four MSSVs per steam generator are OPERABLE to provide overpressure protection for design basis transients occurring at 102% of the pre-Appendix K power uprate licensed power level of 2300 MWt (i.e., 2346 MWt). The LCO, therefore, also requires that four MSSVs per steam generator be OPERABLE.

The OPERABILITY of the MSSVs is defined as the ability to open upon demand within the setpoint tolerances, relieve steam generator overpressure, and reseat when pressure has been reduced. The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the INSERVICE TESTING PROGRAM.

This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB, or Main Steam System integrity.

APPLICABILITY

In MODES 1, 2, and 3, four MSSVs per steam generator are required to be OPERABLE to prevent Main Steam System overpressurization.

In MODES 4 and 5, there are no credible transients requiring the MSSVs. The steam generators are not normally used for heat removal in MODES 5 and 6, and thus cannot be overpressurized; there is no requirement for the MSSVs to be OPERABLE in these MODES.

(continued)

BASES (continued)

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

With one or more MSSVs inoperable, action must be taken so that the available MSSV relieving capacity meets Reference 2 requirements.

Operation with less than all four MSSVs OPERABLE for each steam generator is permissible, if THERMAL POWER is limited to the relief capacity of the remaining MSSVs. This is accomplished by restricting THERMAL POWER so that the energy transfer to the most limiting steam generator is not greater than the available relief capacity in that steam generator.

A.1

In the case of only a single inoperable MSSV on one or more steam generators when the MTC is not positive, a reactor power reduction alone is sufficient to limit primary side heat generation such that overpressurization of the secondary side is precluded for any RCS heatup event. Furthermore, for this case there is sufficient total steam flow capacity provided by the turbine and remaining OPERABLE MSSVs to preclude overpressurization in the event of an increased reactor power due to reactivity insertion, such as in the event of an uncontrolled RCCA bank withdrawal at power. Therefore, Required Action A.1 requires an appropriate reduction in reactor power within 4 hours.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation as described in the attachment to Reference 4, with an appropriate allowance for calorimetric power uncertainty.

B.1 and B.2

In the case of multiple inoperable MSSVs on one or more steam generators, with a reactor power reduction alone there may be insufficient total steam flow capacity provided by the turbine and remaining OPERABLE MSSVs to preclude overpressurization in the event of an increased reactor power due to reactivity insertion, such as in the event of an uncontrolled RCCA bank withdrawal at power. Furthermore,

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

for a single inoperable MSSV on one or more steam generators when the MTC is positive, the reactor power may increase as a result of an RCS heatup event such that flow capacity of the remaining OPERABLE MSSVs is insufficient. Therefore, in addition to Required Action B.1, which specifies an appropriate reduction in reactor power within 4 hours, Required Action B.2 specifies that the Power Range Neutron Flux-High reactor trip setpoint be reduced within 72 hours.

The maximum THERMAL POWER corresponding to the heat removal capacity of the remaining OPERABLE MSSVs is determined via a conservative heat balance calculation as described in the attachment to Reference 4, with an appropriate allowance for Nuclear Instrumentation System trip channel uncertainties.

Required Action B.2 is modified by a Note, indicating that the Power Range Neutron Flux-High reactor trip setpoint reduction is only required in MODE 1. In MODES 2 and 3, the applicable Reactor Protection System trips specified in LCO 3.3.1, "Reactor Protection System Instrumentation," provide sufficient protection.

The allowed Completion Times are reasonable based on operating experience to accomplish the Required Actions in an orderly manner without challenging unit systems.

C.1 and C.2

If the Required Actions are not completed within the associated Completion Time, or if one or more steam generators have ≥ 3 inoperable MSSVs, 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 4 within 12 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the INSERVICE TESTING PROGRAM. The ASME Code, Section XI (Ref. 5), requires that safety and relief valve tests be performed in accordance with ASME OM Code (Ref. 6). According to Reference 6, the following tests are required:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting);

d. Compliance with owner's seat tightness criteria; and

The ASME OM Code requires that all valves be tested every 5 years, and a minimum of 20% of the valves be tested every 24 months. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7.1-2 allows a ± 3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift. The lift settings, according to Table 3.7.1-2, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected to ambient conditions of the valve at operating temperature and pressure.

REFERENCES

1. UFSAR, Section 10.3.2.

2. ASME, Boiler and Pressure Vessel Code, Section III.

3. UFSAR, Section 15.2.

(continued)

BASES

REFERENCES (continued)	4.	NRC Information Notice 94-60, "Potential Overpressure of Main Steam System," August 22, 1994.
	5.	ASME, Boiler and Pressure Vessel Code, Section XI.
	6.	ASME OM Code.

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs)

BASES

BACKGROUND

The MSIVs isolate steam flow from the secondary side of the steam generators following a high energy line break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generators.

One MSIV is located in each main steam line outside, but close to, containment. The MSIVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply, to prevent MSSV and AFW isolation from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the others, and isolates the turbine, Steam Dump System, and other auxiliary steam supplies from the steam generators.

The MSIVs close on a main steam isolation signal generated by either high steam flow coincident with low T_{avg} or with low steam pressure; or high-high containment pressure. The MSIVs fail closed on loss of control or actuation power. The MSIVs fail as is on a loss of instrument air pressure.

A bypass valve is provided around each MSIV to equalize pressure across the valve and to warm up the steam line during unit startup. The bypass valves are motor operated, manually actuated valves, which are normally closed.

A description of the MSIVs is found in the UFSAR, Section 10.3(Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment, discussed in the UFSAR, Section 6.2 (Ref. 2). It is also affected by the accident analysis of the SLB events presented in the UFSAR, Section 15.1.5 (Ref. 3). The design precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand). Furthermore, the design can limit the blowdown through the break that would occur while the MSIVs are closing. This is due to a check valve installed downstream of each MSIV. Upon a failure of an MSIV, the check valve will prevent

(continued)

APPLICABLE SAFETY ANALYSES (continued)

reverse flow in the case of a steam line break in that line. Due to the presence of check valves, the loss of one MSIV was not analyzed.

The limiting case for containment pressure response is the SLB inside containment at hot zero power, with single failure of one steam line check valve. This case releases the largest integrated mass into containment. The pressure rise is very steep initially, then moderates as the break flow rate decreases. The limiting case for containment temperature response is the SLB inside containment from 102% power of the pre-Appendix K power uprate power level of 2300 MWt (i.e., 2346 MWt). This case maximizes the integrated energy deposited into the containment during the early portion of the event. Blowdown fluid enthalpies allow the steam entering the containment to remain superheated. When the containment sprays actuate, the superheated steam is rapidly condensed, and the temperature quickly falls to the saturation temperature at the partial pressure of the steam.

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB inside containment at hot zero power with offsite power available is the limiting case for a post trip return to power. The analysis includes scenarios with offsite power available, and with a loss of offsite power following turbine trip. With offsite power available, the reactor coolant pumps continue to circulate coolant through the steam generators, maximizing the Reactor Coolant System cooldown. With a loss of offsite power, the response of mitigating systems is delayed. Significant single failures considered include loss of one safety injection pump.

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. A steam line break causes a main steam isolation signal to be generated by either high steam flow coincident with low T_{avg} or with low steam pressure, or high-high containment pressure. This action prevents

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

continuous uncontrolled steam release from more than one steam generator.

b. A break outside of containment and upstream from the MSIVs is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs isolates the break and limits the blowdown to a single steam generator.

c. A break downstream of the MSIVs will be isolated by the closure of the MSIVs.

d. Following a steam generator tube rupture, closure of the MSIVs isolates the ruptured steam generator from the intact steam generators to minimize radiological releases.

e. The MSIVs are also utilized during other events such as a feedwater line break. This event is less limiting so far as MSIV OPERABILITY is concerned.

The MSIVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

This LCO requires that three MSIVs in the steam lines be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal.

This LCO provides assurance that the MSIVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite doses comparable to the limits of 10 CFR 50.67.

(continued)

BASES (continued)

APPLICABILITY

The MSIVs must be OPERABLE in MODE 1, and in MODES 2 and 3 except when closed, when there is significant mass and energy in the RCS and steam generators. When the MSIVs are closed, they are already performing the safety function.

In MODE 4, normally most of the MSIVs are closed, and the steam generator energy is low.

In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

ACTIONS

A.1

With one MSIV inoperable in MODE 1, action must be taken to restore it to OPERABLE status within 24 hours. Some repairs to the MSIV can be made with the unit hot. The 24 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs.

The 24 hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a closed system penetrating containment. These valves differ from other containment isolation valves in that the closed system provides an additional means for containment isolation.

B.1

If the MSIV cannot be restored to OPERABLE status within 24 hours, 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 MODE 2 within 6 hours and Condition C would be entered. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging unit systems.

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Condition C is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

The 8 hour Completion Time is reasonable, considering the low probability of an accident occurring during this time period that would require a closure of the MSIVs.

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSIVs must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

D.1 and D.2

If the MSIVs cannot be restored to OPERABLE status or are not closed 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 at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is within limits (Ref.4) on an actual or simulated actuation signal. The maximum MSIV closure time is less than that assumed in the accident and

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.2.1 (continued)

containment analyses with the exception of closure of the MSIVs for a MSLB at 100% RTP, in which case MSIV closure in 2 seconds is assumed for MSIVs which close in the forward flow direction. The MSIVs should not be tested at power, since even a part stroke exercise increases the risk of a valve closure when the unit is generating power. As the MSIVs are not tested at power, they are exempt from the ASME Code, Section XI (Ref. 5), requirements during operation in MODE 1 or 2.

The Frequency is in accordance with the INSERVICE TESTING PROGRAM. The specified Frequency for valve closure time is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the specified Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This test is conducted in MODE 3 with the unit at operating temperature and pressure, as discussed in Reference 5 exercising requirements. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

REFERENCES

1. UFSAR, Section 10.3.
2. UFSAR, Section 6.2.
3. UFSAR, Section 15.1.5.
4. TRM, Section 4.0
5. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.7 PLANT SYSTEMS

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

BASES

BACKGROUND

The MFIVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). The safety related function of the MFRVs is to provide the second isolation of MFW flow to the secondary side of the steam generators following an HELB. Closure of the MFIVs or MFRVs, and bypass valves terminates flow to the steam generators, terminating the event for feedwater line breaks (FWLBs) occurring upstream of the MFIVs or MFRVs. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the MFIVs will be mitigated by their closure. Closure of the MFIVs or MFRVs, and bypass valves, effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside containment, and reducing the cooldown effects for SLBs.

The safety grade MFIVs or MFRVs, and bypass valves (FCV-479, 489 & 499) isolate the nonsafety related portions from the safety related portions of the system. Because an earthquake is not assumed to occur coincident with a spontaneous break of safety related secondary piping, loss of the non-safety grade bypass valves (FW-9A, B & C) is not assumed. If the single active failure postulated for a secondary pipe break is the failure of a safety grade bypass valve to close, then credit is taken for closing the non-safety grade bypass valve. In the event of a secondary side pipe rupture inside containment, the valves limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of auxiliary feedwater (AFW) to the intact loops.

One MFIV, one MFRV, and two bypass valves are located on each MFW line, outside but close to containment. The bypass line, with two bypass valves, bypasses both the MFIV and the MFRV. The MFIVs, MFRVs, and bypass valves are located upstream of the AFW injection point so that AFW may be supplied to the steam generators following MFIV or MFRV closure. The piping volume from these valves to the steam generators must be accounted for in calculating mass and energy releases, and refilled prior to AFW reaching the steam generator following either an SLB or FWLB.

(continued)

BASES

BACKGROUND (continued)	The MFIVs, MFRVs, and bypass valves close on receipt of a safety injection signal. They may also be actuated manually. The MFRV and bypass valves for a specific steam generator will also close on a steam generator water level – high signal. In addition to the MFIVs, MFRVs, and bypass valves, a check valve outside containment is available. A description of the MFIVs and MFRVs is found in the UFSAR, Section 10.4.6 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The design basis of the MFIVs and MFRVs is established by the analyses for the large SLB. It is also influenced by the accident analysis for the large FWLB. Closure of the MFIVs or MFRVs, and bypass valves, is relied on to terminate an SLB for core response analysis and excess feedwater event upon the receipt of a safety injection signal. Failure of an MFIV, MFRV, or bypass valve to close following an SLB or FWLB can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following an SLB or FWLB event. The MFIVs, MFRVs, and bypass valves satisfy Criterion 3 of the NRC Policy Statement.
LCO	This LCO ensures that the MFIVs, MFRVs, and bypass valves will isolate MFW flow to the steam generators, following an FWLB or main steam line break. The MFIVs, MFRVs, and one bypass valve in each line will also isolate the nonsafety related portions from the safety related portions of the system. This LCO requires that three MFIVs, three MFRVs, and six bypass valves be OPERABLE. The MFIVs, MFRVs, and bypass valves are considered OPERABLE when isolation times are within limits and they close on an isolation actuation signal. Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or FWLB inside containment.
APPLICABILITY	The MFIVs, MFRVs, and bypass valves must be OPERABLE whenever there is significant mass and energy in the Reactor

(continued)

BASES

APPLICABILITY (continued)

Coolant System and steam generators. This ensures that, in the event of an HELB, a single failure cannot result in the blowdown of more than one steam generator. In MODES 1, 2, and 3, the MFIVs, MFRVs, and bypass valves are required to be OPERABLE to limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment, and to limit reactivity addition as a result of plant cooldown. When the valves are closed or the flowpath to the steam generator is isolated by a closed manual valve, the safety function is satisfied.

In MODES 4, 5, and 6, steam generator energy is low. Therefore, the MFIVs, MFRVs, and bypass valves are normally closed since MFW is not required.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each valve.

A.1 and A.2

With one MFIV in one or more flow paths inoperable, action must be taken to restore the affected valve(s) to OPERABLE status, or to close or isolate inoperable affected valve(s) within 72 hours. When these valve(s) are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valve(s) and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFIVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

With one MFRV in one or more flow paths inoperable, action must be taken to restore the affected valve(s) to OPERABLE status, or to close or isolate inoperable affected valve(s) within 72 hours. When these valve(s) are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valve(s) and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable MFRVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls to ensure that the valves are closed or isolated.

C.1 and C.2

With one bypass valve in one or more flow paths inoperable, action must be taken to restore the affected valve(s) to OPERABLE status, or to close or isolate inoperable affected valve(s) within 72 hours. When these valve(s) are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on operating experience.

Inoperable bypass valves that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

D.1

With two inoperable valves in the same flow path, there may be no redundant system to operate automatically and perform the required safety function. Although the containment can be isolated with the failure of two valves in parallel in the same flow path, the double failure can be an indication of a common mode failure in the valves of this flow path, and as such, is treated the same as a loss of the isolation capability of this flow path. Under these conditions, affected valves in each flow path must be restored to OPERABLE status, or the affected flow path isolated within 8 hours. This action returns the system to the condition where at least one valve in each flow path is performing the required safety function. The 8 hour Completion Time is reasonable, based on operating experience, to complete the actions required to close the MFIV or MFRV, or otherwise isolate the affected flow path.

E.1 and E.2

If the MFIV(s), MFRV(s), and bypass valve(s) cannot be restored to OPERABLE status, or closed, or isolated 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 4 within 12 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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that the closure time of each MFRV and bypass valve is within limits (Ref. 4) on an actual or simulated actuation signal. The MFRV, and bypass valve closure times are assumed in the accident and containment analyses (Ref. 2). This Surveillance is normally performed upon returning the unit to operation following a refueling outage. These valves should not be tested at power since even a part stroke exercise increases the risk of a valve closure with the unit generating power. This is consistent with the ASME Code, Section XI (Ref. 3).

The Frequency for this SR is in accordance with the INSERVICE TESTING PROGRAM. The specified Frequency for valve closure is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the specified Frequency.

SR 3.7.3.2

This SR verifies that the closure time of each MFIV is within limits (Ref. 4) on an actual or simulated actuation signal. The MFIV closure times are assumed in the accident and containment analyses (Ref. 2). This Surveillance is normally performed upon returning the unit to operation following a refueling outage. These valves should not be tested at power since even a part stroke exercise increases the risk of a valve closure with the unit generating power. This is consistent with the ASME Code, Section XI (Ref. 3).

The Frequency for this SR is in accordance with the INSERVICE TESTING PROGRAM. The specified Frequency for valve closure is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the specified Frequency.

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 10.4.6.
2. UFSAR, Chapter 15.
3. ASME, Boiler and Pressure Vessel Code, Section XI.
4. TRM, Section 4.0

B 3.7 PLANT SYSTEMS

B 3.7.4 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply. The AFW pumps take suction from the condensate storage tank (CST) (LCO 3.7.5) and pump to the steam generator secondary side via connections to the main feedwater (MFW) piping. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) (LCO 3.7.1) or atmospheric dump valves. If the main condenser is available, steam may be released via the steam dump valves and recirculated to the CST.

The AFW System consists of a motor driven subsystem and a steam driven subsystem. The motor driven subsystem consists of two motor driven AFW pumps each of which provides 100% of AFW flow capacity. Each motor driven pump is powered from an independent emergency power supply and feeds a common header to supply three AFW injection lines to the three steam generators. The AFW pump suction line and discharge line to Steam Generator "B" associated with AFW pump "A" is one AFW flow path and power operated valves are powered from an emergency power supply. The AFW pump suction line and discharge line to Steam Generator "C" associated with AFW pump "B" is the second AFW flow path and power operated valves are powered from the other emergency power supply. The "swing" AFW injection line to Steam Generator "A" is powered from both emergency power supplies via an automatic bus transfer switch and is the third motor driven AFW flow path. The pumps are equipped with cross tied recirculation lines to prevent operation against a closed system.

The steam driven subsystem provides a second independent and diversely powered means of providing AFW to the steam generators. The steam driven system provides approximately 200% of the required AFW flow through injection lines that are separate from the motor driven subsystem. One steam supply valve to the steam driven auxiliary feedwater pump and two AFW injection valves are powered from an alternating

(continued)

BASES

BACKGROUND (continued)

current (ac) emergency power supply. The other two steam supply valves and one injection valve are powered from the other ac emergency power supply. Emergency procedures provide for operation of the valves manually in the event that power is not available. The pump is equipped with a recirculation line to prevent operation against a closed system. All steam supply lines and valves, pump suction line and valves, and steam generator injection lines and valves associated with the steam driven AFW subsystem constitute one AFW flow path. The steam driven AFW pump receives steam from three main steam lines upstream of the main steam isolation valves. Each of the steam feed lines will supply 100% of the requirements of the steam driven AFW pump.

The AFW System is capable of supplying feedwater to the steam generators during all modes of operation.

The steam driven AFW pump supplies a common header capable of feeding all steam generators. One pump at full flow is sufficient to remove decay heat and cool the unit to residual heat removal (RHR) entry conditions. Thus, the requirement for diversity in motive power sources for the AFW System is met.

The AFW System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the setpoint of the MSSVs. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions.

The AFW System actuates automatically on steam generator water level - low-low, loss of offsite power, safety injection, and trip of all MFW pumps.

The AFW System is discussed in the UFSAR, Section 10.4.8 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

steam generators at pressures corresponding to the lowest steam generator safety valve set pressure plus 3%.

In addition, the AFW System must supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting Design Basis Accidents (DBAs) and transients for the AFW System are as follows:

a. Feedwater Line Break (FWLB), which the overcooling aspect of the transient is bounded by the Steamline Break (Ref. 2); and

b. Loss of MFW (Ref. 3).

In addition, the minimum available AFW flow and system characteristics are serious considerations in the analysis of a small break loss of coolant accident (LOCA).

The AFW System design is such that in the event of a complete loss of offsite power, decay heat removal would continue to be assured by the availability of either the steam driven AFW pump, or one of the two motor driven AFW pumps, along with steam discharge to the atmosphere through the main steam safety valves (MSSVs). One motor driven AFW pump can supply sufficient feedwater for decay heat removal. Feedwater is available from the condensate storage tank by gravity feed to the AFW pumps. LCO 3.7.5, "Condensate Storage Tank (CST)," provides assurance of the availability of at least 35,000 gallons of water in the CST, which is the minimum amount needed for two hours operation in MODE 3. Should feedwater be required beyond two hours, AFW pump suction would be switched to the Service Water System supply.

The AFW System satisfies the requirements of Criterion 3 of the NRC Policy Statement.

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary.

(continued)

BASES

LCO (continued)

Three AFW pumps and four AFW flow paths configured as listed below are required to be OPERABLE to ensure diverse and redundant capability for AFW injection to the steam generators in events accompanied by a loss of offsite power and a single failure:

1) Each motor driven AFW pump suction line and valves, discharge line and valves, providing flow paths to steam generators B and C (two paths total).

2) The "swing" AFW injection valve, powered from the automatic bus transfer switch, and injection line to steam generator "A" constitutes the third motor driven AFW flow path.

3) The steam supply lines and valves, pump suction line and valves, and injection lines and valves constitute the steam driven AFW flow path.

The AFW System is considered OPERABLE when the pumps and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. This requires that the two motor driven AFW pumps be OPERABLE in three flow paths, each supplying AFW to separate steam generators. The steam driven AFW pump is required to be OPERABLE with redundant steam supplies from each of three main steam lines upstream of the MSIVs, and shall be capable of supplying AFW to any of the steam generators. The piping, valves, instrumentation, and controls in the steam driven flow paths also are required to be OPERABLE.

The LCO is modified by a Note indicating that one AFW motor driven pump and flow path is required to be OPERABLE in MODE 4. This is because of the reduced heat removal requirements and short period of time in MODE 4 during which the AFW is required and the insufficient steam available in MODE 4 to power the steam driven AFW pump.

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW is lost. In addition, the AFW System is required to supply enough makeup water to replace the steam

(continued)

BASES

APPLICABILITY (continued)

generator secondary inventory, lost as the unit cools to MODE 4 conditions.

In MODE 4 the AFW System may be used for heat removal via the steam generators.

In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.

ACTIONS

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

When an AFW pump is found to be inoperable, its associated flow path is also intrinsically inoperable. The "swing" flow path is not made inoperable by the inoperability of a single motor driven AFW pump. Likewise, when a flow path is found inoperable in a manner that prevents flow through an AFW pump, the affected AFW pump is also intrinsically inoperable.

A.1

If one AFW pump or one or two AFW flow path(s) are inoperable, action must be taken to restore them to OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based upon the following:

a. With any single AFW pump or one or two flow path(s) inoperable, redundant capability to inject flow into at least one steam generator exists.

b. With the AFW "swing" injection flow path inoperable concurrent with another motor driven flow path inoperable, redundant capability to inject flow into at least one steam generator exists.

Other combinations of inoperable AFW flow paths and pumps result in entry into either Condition B or Condition C

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(continued)

BASES

ACTIONS

A.1 (continued)

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 8 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 7 days and 8 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

(continued)

ACTIONS (continued)

B.1

With two motor driven AFW pumps inoperable or three motor driven AFW flow paths inoperable, a diverse and redundant means of supplying AFW to the three steam generators is lost. The steam driven AFW pump and flow path remains in service to provide injection capability to all three steam generators. Action must be taken to restore one inoperable motor driven AFW pump or flow path to OPERABLE status within 24 hours. The 24 hour Completion Time is reasonable, based on the remaining capabilities afforded by the AFW System, time needed for repairs, and the low probability of a DBA occurring during this time period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 8 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 24 hours and 8 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

C.1 and C.2

When Required Action A.1 or B.1 cannot be completed within the required Completion Time, 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 4 within 18 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.

In MODE 4 with two AFW trains inoperable, operation is allowed to continue because only one motor driven pump AFW train is required in accordance with the Note that modifies the LCO. Although not required, the unit may continue to cool down and initiate RHR.

(continued)

BASES

ACTIONS (continued)

D.1 and D.2

With the steam driven AFW pump or flow path and one motor driven pump or flow path inoperable, a diverse and redundant means of supplying AFW to the steam generators is lost. One motor driven AFW pump and at least one flow path remains in service to provide injection capability to at least one steam generator; however, redundant capability to feed at least two steam generators is not assured. Action must be taken to place the unit 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 4 within 18 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.

In MODE 4 with only one motor driven AFW pump and flow path operable, operation is allowed to continue because only one motor driven AFW pump and flow path is required in accordance with the Note that modifies the LCO. Although not required, the unit may continue to cool down and initiate RHR.

E.1

If all three AFW pumps or all four AFW flow paths are inoperable in MODE 1, 2, or 3, the unit is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety related equipment. In such a condition, the unit should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one AFW train to OPERABLE status.

Required Action E.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one AFW train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the unit into a less safe condition.

(continued)

BASES

ACTIONS (continued)

F.1

In MODE 4, either the reactor coolant pumps or the RHR loops can be used to provide forced circulation. This is addressed in LCO 3.4.6, "RCS Loops - MODE 4." With one required AFW train inoperable, action must be taken to immediately restore the inoperable train to OPERABLE status. The immediate Completion Time is consistent with LCO 3.4.6.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

Verifying the correct alignment for manual, power operated, and automatic valves in the AFW System water and steam supply flow paths provides assurance that the proper flow paths will exist for AFW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.4.2

Verifying that each AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of centrifugal pump performance required by Section XI of the ASME Code (Ref. 4) to monitor centrifugal pump performance. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. This ensures that pump performance is consistent with the pump curve. Performance of inservice testing discussed in the ASME Code, Section XI (Ref. 4)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.4.2 (continued)

satisfies this requirement. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test.

SR 3.7.4.3

This SR verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an AFW actuation signal, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note that states the SR is not required in MODE 4 when AFW is being used for heat removal. In MODE 4, the required AFW train is already aligned and operating.

SR 3.7.4.4

This SR verifies that the AFW pumps will start in the event of any accident or transient that generates an AFW actuation

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.4.4 (continued)

signal by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal in MODES 1, 2, and 3. In MODE 4, the autostart function is not required. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. Note 1 indicates that the SR be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test. Note 2 states that the SR is not required in MODE 4. In MODE 4, the heat removal requirements would be less providing more time for operator action to manually start the required AFW pump.

SR 3.7.4.5

This SR verifies proper AFW System alignment and flow path OPERABILITY from the CST to each SG following extended outages to determine that no misalignment of valves has occurred. The SR is performed prior to entering MODE 2 after more than 30 days in MODE 5 or 6. OPERABILITY of AFW flow paths must be verified before sufficient core heat is generated that would require the operation of the AFW System during a subsequent shutdown. The Frequency is reasonable, based on engineering judgment and other administrative controls that ensure that flow paths remain OPERABLE.

This SR is modified by a Note that allows entry into and operation in MODE 3 and MODE 2 prior to performing the SR for the steam driven AFW pump. This is necessary because sufficient decay heat is not available following an extended outage. The unit must be at a point of adding minimum core heat in order to provide sufficient steam to operate the steam driven AFW pump to verify water flow.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.4.6

This SR verifies that the automatic bus transfer switch associated with the "swing" motor driven AFW flow path discharge valve V2-16A will function properly to automatically transfer the power source from the aligned emergency power source to the other emergency power source upon loss of power to the aligned emergency power source. The Surveillance consists of two tests to assure that the switch will perform in either direction. One test is performed with the automatic bus transfer switch aligned to one emergency power source initially, and the test is repeated with the switch initially aligned to the other emergency power source. Periodic testing of the switch is necessary to demonstrate OPERABILITY. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 10.4.8.
2. UFSAR, Section 15.2.8.
3. UFSAR, Section 15.2.7.
2. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.7 PLANT SYSTEMS

B 3.7.5 Condensate Storage Tank (CST)

BASES

BACKGROUND

The CST provides a makeup grade source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The CST provides a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (LCO 3.7.4). The steam produced is released to the atmosphere by the main steam safety valves (MSSVs) or the power operated relief valves. The AFW pumps operate with a continuous recirculation to the CST.

When the main steam isolation valves are open, the preferred means of heat removal is to discharge steam to the condenser by the nonsafety grade path of the steam dump valves. The condensed steam is returned to the CST by the condensate pump. This has the advantage of conserving condensate while minimizing releases to the environment.

The CST is designed to Seismic Category I to ensure availability of the feedwater supply.

A backup water supply to the AFW System is provided through a direct connection between one of the Service Water System (SWS) headers and the AFW pumps suction header. The two systems are normally isolated by two locked closed valves in series (AFW24 and SW118). A normally open tell-tale drain from the common section of pipe between the two locked closed valves provides indication of valve leakage.

A description of the CST is found in the UFSAR, Section 9.2.5 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The CST provides cooling water to remove decay heat following all events in the accident analysis as discussed in the UFSAR, Chapters 6 and 15 (Refs. 2 and 3, respectively). For anticipated operational occurrences and accidents that do not affect the OPERABILITY of the steam generators, the analysis assumption is 2 hours at MODE 3, steaming through the MSSVs.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limiting event for the condensate volume is the loss of offsite power because of the loss of makeup capability to the CST. A backup water supply to feed the steam generators is provided through a direct connection between the Service Water System (SWS) and the AFW system.

The CST satisfies Criterion 3 of the NRC Policy Statement.

LCO

To satisfy operational requirements, the CST must contain sufficient cooling water to remove decay heat for 2 hours following a reactor trip from 102% of the pre-Appendix K power uprate licensed power level of 2300 MWt (i.e., 2346MWT), assuming a coincident loss of offsite power and the most adverse single active failure. In doing this, it must retain sufficient water to ensure adequate net positive suction head for the AFW pumps.

The CST level required is equivalent to a usable volume of ≥ 35,000 gallons, which is based on holding the unit in MODE 3 for 2 hours.

The OPERABILITY of the CST is determined by maintaining the tank level at or above the minimum required level.

The backup SWS supply to the AFW System must also be OPERABLE to satisfy decay heat removal requirements in the event of a loss of normal make-up capability to the CST resulting from a loss of offsite power.

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when a steam generator is being used for heat removal, the CST is required to be OPERABLE.

In MODE 5 or 6, the CST is not required because the AFW System is not required.

ACTIONS

A.1 and A.2

If the CST level is not within limits, the OPERABILITY of the backup supply should be verified by administrative means within 4 hours and once every 12 hours thereafter.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

OPERABILITY of the backup feedwater supply must include verification that the flow paths from the backup water supply to the AFW pumps are OPERABLE, and that the backup supply has the required volume of water available. If the backup SWS supply to the AFW System is being used to satisfy Required Action A.1, verification of OPERABILITY of the backup feedwater supply requires a visual inspection of the water supply connection between the SWS and the AFW System to verify that the valves are in place and locked closed, the tell-tale drain valve is open, and the piping is intact and free from leakage. The CST must be restored to OPERABLE status within 24 hours, because the backup supply may be performing this function in addition to its normal functions. The 4 hour Completion Time is reasonable, based on operating experience, to verify the OPERABILITY of the backup water supply. The 24 hours Completion Time is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period requiring the CST.

B.1 and B.2

If the CST cannot be restored to OPERABLE status within the associated Completion Time, the 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 4, without reliance on the steam generator for heat removal, within 18 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1 and C.2

If the service water supply to the AFW System is inoperable, the plant is not assured of a safety related cold shutdown capability. Therefore, 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 4, without reliance on a steam generator for heat removal, within 18 hours. The allowed Completion Times are

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

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

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

This SR verifies that the CST contains the required volume of cooling water. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.5.2

This SR verifies by administrative means that the backup water supply to the AFW System from the SWS is OPERABLE. In this situation, verification by administrative means is necessary because it is not prudent to cycle the valves and risk introduction of non-feedwater grade water into the SGs. An administrative verification of OPERABILITY is simply a visual inspection of the water supply connection between the SWS and the AFW System to verify that the valves are in place and locked closed, the tell-tale drain valve is open, and the piping is intact and free from leakage.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 9.2.5.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.

B 3.7 PLANT SYSTEMS

B 3.7.6 Component Cooling Water (CCW) System

BASES

BACKGROUND

The CCW System provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, the CCW System also provides this function for various nonessential components, as well as the spent fuel storage pool. The CCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Service Water System, and thus to the environment.

The CCW System consists of three pumps, two heat exchangers, a supply and return header, a surge tank, and associated piping, valves, and instrumentation. The "B" and "C" CCW pumps are each powered by a separate safety related bus. The "A" CCW pump is powered by the nonsafety related dedicated shutdown bus. The surge tank accommodates changes in water volume in the system and ensures that sufficient net positive suction head is available for the CCW pumps.

All CCW pumps automatically start on low pump discharge header pressure. All CCW pumps in operation upon initiation of a Safety Injection (SI) signal will continue to operate as long as normal power is available. Upon loss of normal power, the "B" and "C" CCW pumps are automatically loaded onto the emergency diesel generator (EDG) buses as long as an SI signal is not present. If a Containment Spray signal occurs after the EDG loading sequence has been completed, the CCW pumps are stripped from the buses. The "B" and "C" CCW pumps are not loaded onto the EDG buses as part of the SI loading sequence, however, they are capable of manual start when EDG loads allow.

Additional information on the design and operation of the system, along with a list of the components served, is presented in the UFSAR, Section 9.2.2 (Ref. 1). The principal safety related function of the CCW System is the removal of decay heat from the reactor via the Residual Heat Removal (RHR) System. This may be during a normal or post accident cooldown and shutdown.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The design basis of the CCW System is for one CCW pump and one CCW heat exchanger to accommodate the post loss of coolant accident (LOCA) heat removal loads from the RHR heat exchangers and safety injection pump seals. Should either a required CCW pump or a CCW heat exchanger fail, one of the two standby pumps and the standby heat exchanger provide 100 percent backup.

The CCW System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power.

The CCW System also functions to cool the unit from RHR entry conditions (T_{cold} < 350ºF), to MODE 5 (T_{cold} < 200ºF), during normal and post accident operations. The time required to cool from 350ºF to 200ºF is a function of service water temperature and the number of CCW and RHR trains operating. One CCW train is sufficient to remove decay heat during subsequent operations with T_{cold} < 200ºF. This assumes a maximum service water temperature of 97ºF occurring simultaneously with the maximum heat loads on the system.

The CCW System satisfies Criterion 3 of the NRC Policy Statement.

LCO

The CCW trains are independent of each other to the degree that each CCW pump has separate controls and power supplies and the operation of one does not depend on the other. In the event of a DBA, one CCW train powered from an emergency power source is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two trains of CCW powered from an emergency power source must be OPERABLE. At least one CCW train will operate assuming the worst case single active failure occurs coincident with a loss of offsite power.

A CCW train is considered OPERABLE when:

a. The required pump and heat exchanger are OPERABLE; and

(continued)

BASES

LCO (continued)

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

The isolation of CCW from other components or systems not required for safety may render those components or systems inoperable but does not affect the OPERABILITY of the CCW System.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CCW System is a normally operating system, which must be prepared to perform its post accident safety functions, primarily RCS heat removal, which is achieved by cooling the RHR heat exchanger.

Although the LCO for the CCW System is not applicable in MODES 5 and 6, the capability of the CCW System to perform its necessary related support functions may be required for OPERABILITY of supported systems.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," be entered if an inoperable CCW train results in an inoperable RHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

If one required CCW train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE CCW train is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this period.

B.1 and B.2

If the required CCW train 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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR is modified by a Note indicating that the isolation of the CCW flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CCW System.

Verifying the correct alignment for manual, power operated, and automatic valves in the required CCW flow path provides assurance that the proper flow paths exist for CCW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.6.2

This SR verifies proper automatic operation of the required CCW pumps on an actual or simulated LOP DG start undervoltage signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

REFERENCES 1. UFSAR, Section 9.2.2.

B 3.7 PLANT SYSTEMS

B 3.7.7 Service Water System (SWS)

BASES

BACKGROUND

The SWS 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 SWS also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The SWS is an open loop system, consisting of four 8000 gpm capacity wet pit pumps, two redundant 30" diameter headers, and two full capacity booster pumps which supply service water to the four containment fan coolers. Two or three of the four service water pumps normally operate, depending on system demand, and discharge into the two headers, which are cross-connected at the pump discharge. Only one booster pump normally operates. Following a simultaneous Loss of Coolant Accident (LOCA) and loss of offsite power, the cooling water requirements for all four fan coolers and the other essential loads can be supplied by any two of the four SWS pumps. Service water to at least one component cooling water heat exchanger is assured with a single failure of any component. The SWS pumps and booster pumps are automatically started upon receipt of a Safety Injection (SI) signal, and all essential valves are aligned to their post accident positions. The SWS also provides a backup water supply for the Auxiliary Feedwater (AFW) System and the Isolation Valve Seal Water (IVSW) injection tank.

To prevent degradation of the SWS pressure to vital components, service water supply to the turbine building loop is isolated on actuation of low service water header pressure for one minute coincident with a Turbine Trip signal. Two isolation valves powered from emergency power sources isolate each of the two loop headers from the Turbine Building. To provide single failure capability, a third isolation valve is provided that receives power from an automatic bus transfer switch that can be powered from either emergency power source. This valve isolates both SWS headers from the Turbine Building

(continued)

BASES

BACKGROUND (continued)

Additional information about the design and operation of the SWS, 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 SWS is the removal of decay heat from the reactor via the Component Cooling Water (CCW) System.

APPLICABLE SAFETY ANALYSES

The design basis of the SWS is to provide cooling water to those components necessary to remove core decay heat following a design basis LOCA as discussed in the UFSAR, Section 6.2 (Ref. 2). The system is sized to ensure adequate heat removal, based on highest expected temperatures of cooling water, maximum loadings, and leakage allowances. The SWS is designed to perform its function with a single failure of any active component, assuming the loss of offsite power.

The SWS, in conjunction with the CCW System, also cools the unit from residual heat removal (RHR), as discussed in the UFSAR, Section 5.4.4, (Ref. 3) 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 and SW supply temperature. One SWS train is sufficient to remove decay heat during subsequent operations in MODES 5 and 6. This assumes a maximum SWS temperature of 97ºF occurring simultaneously with maximum heat loads on the system.

The SWS satisfies Criterion 3 of the NRC Policy Statement.

LCO

Two SWS trains are required to be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, assuming that the worst case single active failure occurs coincident with the loss of offsite power.

An SWS train is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. Two SWS pumps are OPERABLE;

b. One SWS booster pump is OPERABLE

(continued)

BASES

LCO (continued)

c. The associated piping, valves, and permanent protective enclosures (e. g, north header enclosure grating), valves, and instrumentation and controls required to perform the safety related function are OPERABLE.

The SWS Turbine Building loop isolation valves are considered OPERABLE when each header isolation valve and the isolation valve powered from the automatic bus transfer switch are OPERABLE.

APPLICABILITY

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

Although the LCO for the SWS is not applicable in MODES 5 and 6, the capability of the SWS to perform its necessary related support functions may be required for OPERABILITY of supported systems.

ACTIONS

A.1

If one SWS train is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE SWS train is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE SWS train could result in loss of SWS function. Required Action A.1 is modified a Note. The Note indicates that the applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources - Operating," should be entered if an inoperable SWS train results in an inoperable emergency diesel generator. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE train, and the low probability of a DBA occurring during this time period.

B.1 and B.2

If one SWS Turbine Building loop isolation valve is inoperable, the valve must be closed and deactivated within 72 hours. In the closed and deactivated condition, the remaining OPERABLE loop isolation valves can perform the

(continued)

ACTIONS

B.1 and B.2 (continued)

required isolation function and withstand a single failure. It should be noted, however, that in the event the inoperable valve is the common loop isolation valve (V6-16C), connected to both emergency power sources through an automatic bus transfer switch, placing this valve in a closed and deactivated condition isolates all service water from the Turbine Building, and will ultimately result in a unit shutdown.

The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE loop isolation valve(s), and the low probability of a DBA occurring during this time period.

In the event the inoperable loop isolation valve is closed and deactivated, it must be verified to be in that condition on a periodic basis. This periodic verification is necessary to assure that the inoperable valve is fulfilling its isolation function. The Completion Time of 31 days is appropriate because of the low probability of misalignment of the valve during this time period.

C.1

If two SWS Turbine Building loop isolation valves are inoperable, one of the inoperable valves must be closed and deactivated within 2 hours. In the closed and deactivated condition, the remaining OPERABLE loop isolation valve can perform the required isolation function. It should be noted, however, that placing the common loop isolation valve, V6-16C, which is connected to both emergency power sources through an automatic bus transfer switch, in the closed and deactivated condition isolates all service water from the Turbine Building, and will ultimately result in a unit shutdown. Therefore, V6-16A or V6-16B is the preferred valve to close when inoperable.

The 2 hour Completion Time is reasonable to either restore at least one valve to OPERABLE status, or place it in the closed and deactivated condition, based on the time usually required to accomplish these tasks, and consequently restore the SWS Turbine Building loop isolation function.

(continued)

ACTIONS (continued)

D.1 and D.2

If the Required Actions and associated Completion Times of Conditions A, B, or C cannot be met, 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

This SR is modified by a Note indicating that the isolation of the SWS components or systems may render those components inoperable, but does not affect the OPERABILITY of the SWS.

Verifying the correct alignment for manual, power operated, and automatic valves in the SWS flow path provides assurance that the proper flow paths exist for SWS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.7.2

This SR verifies proper automatic operation of the SWS valves on an actual or simulated actuation signal. The SWS 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

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.7.2 (continued)

controls. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.7.3

This SR verifies proper automatic operation of the SWS pumps and SWS booster pumps on an actual or simulated actuation signal. The SWS is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.7.4

This SR verifies that the automatic bus transfer switch associated with turbine building service water isolation valve V6-16C, will function properly to automatically transfer the power source from the aligned emergency power source to the other emergency power source upon loss of power to the aligned emergency power source. The surveillance consists of two tests to assure that the switch will perform in either direction. One test is performed with the automatic bus transfer switch aligned to one emergency power source initially, and the test is repeated with the switch initially aligned to the other emergency power source. Periodic testing of the switch is necessary to demonstrate OPERABILITY.

(continued)

BASES

SURVEILLANCE REQUIREMENTS	SR 3.7.7.4 (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 9.2.1. 2. UFSAR, Section 6.2. 3. UFSAR, Section 5.4.4.

B 3.7 PLANT SYSTEMS

B 3.7.8 Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The UHS provides a heat sink for processing and operating heat from safety related components during a transient or accident, as well as during normal operation. This is done by utilizing the Service Water System (SWS) and the Component Cooling Water (CCW) System.

The UHS has been defined as the Lake Robinson Impoundment, including necessary retaining structures, and the canals or conduits connecting the sources with, but not including, the cooling water system intake structures as discussed in the UFSAR, Section 9.2.4 (Ref. 1). The two principal functions of the UHS are the dissipation of residual heat after reactor shutdown, and dissipation of residual heat after an accident.

The basic performance requirements are that a 22 day supply of water be available, and that the design basis temperatures of safety related equipment not be exceeded.

Lake Robinson is a cooling impoundment of Black Creek. Water is taken directly from the lower end of the lake through a submerged inlet to an intake structure, and pumped through an underground conduit system for use in the plant. It is discharged back to the lake near its upper end through a 4.2 mile long discharge canal. Service water is carried to the plant through two parallel thirty inch diameter conduits, and is returned through a single thirty inch conduit to the discharge canal via the circulating water return.

The impoundment dam is equipped with two Howell Bunger valves to allow small adjustments of lake level and provide limited tail flow temperature control. Flow spills over two electrically-operated tainter gates at an elevation of 220 ft mean sea level (MSL) under normal operation as well as discharging through the Howell Bunger valves when needed. Peak flows at Lake Robinson can be controlled by opening the tainter gates. The tainter gates are provided with an internal combustion engine as a back-up power source in the event of electrical failure.

(continued)

APPLICABLE SAFETY ANALYSES

The UHS is the sink for heat removed from the reactor core following all accidents and anticipated operational occurrences in which the unit is cooled down and placed on residual heat removal (RHR) operation. Since the UHS is the normal heat sink for condenser cooling via the Circulating Water System, unit operation at full power is its maximum heat load. Its maximum post accident heat load occurs at the time that recirculation begins after a design basis loss of coolant accident (LOCA). Near this time, the unit switches from injection to recirculation and the containment cooling systems and RHR are required to remove the core decay heat.

The operating limits are based on conservative heat transfer analyses for the worst case LOCA and maintaining adequate net positive suction head (NPSH) for the SWS pumps. The UHS at the minimum allowable level of 218 ft MSL provides a 22 day supply of cooling water to the SWS pumps under worst case local meteorological conditions. After 22 days, the minimum NPSH for the SWS pumps is reached when the lake level drops to 210.64 ft MSL. The lake surface area at 210.64 ft MSL is capable of providing decay heat cooling for the plant without exceeding the 97°F maximum SWS temperature requirement. Therefore, the necessary lake level for adequate NPSH for the SWS pumps is more limiting than the lake surface area necessary for decay heat removal. The 22 day supply of water is based on the lake volume and surface area values provided in References 2 and 3, an evaporation rate of 35 ft^3/sec (Ref. 4) that assumes both Unit 1 (fossil Plant) and Unit 2 operating at 100% power for 6 hours, an evaporation rate of 17 ft^3/sec that assumes Unit 1 in operation and Unit 2 shut down for the remaining 22 day period under maximum evaporation conditions, a head flow of 16 ft^3/sec which is based upon the minimum head flow measured at the Black Creek inlet over the past 30 years (Ref. 5), and a fully open Howell Bunger valve which provides an average flow of 260 ft^3/sec. No credit is taken for natural springs, precipitation or other drainage input into the lake for the 22day period. The opening and testing of the tainter gates is administratively limited to approximately 2.5 inches except for flood control measures necessary to protect the integrity of the dam which approximates the capacity of one Howell Bunger valve. A failure of a tainter gate to reclose when the gate is raised 2.5 inches or less is bounded by a fully open Howell Bunger valve in the analysis.

With the shutdown of the Unit 1 (fossil plant), the 22 day supply of minimum allowable lake level is conservative. The calculation assumed that Unit 1 (fossil plant) was at 100% power for the 22 day period

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	and thus providing heat and evaporation to Lake Robinson. Since Unit 1 (fossil plant) is shutdown, the evaporation rate will be less and the ultimate heat sink will be available for SW pump NPSH greater than 22 days. A new calculation is not provided and the 22 day calculation is conservative. The UHS satisfies Criterion 3 of the NRC Policy Statement.
LCO	The UHS is required to be OPERABLE and is considered OPERABLE if it contains a sufficient volume of water at or below the maximum temperature that would allow the SWS to operate for at least 22 days following the design basis LOCA without the loss of NPSH, and without exceeding the maximum design temperature of the equipment served by the SWS. To meet this condition, the UHS temperature should not exceed 97ºF and the level should not fall below 218 ft MSL during normal unit operation.
APPLICABILITY	In MODES 1, 2, 3, and 4, the UHS is required to support the OPERABILITY of the equipment serviced by the UHS and required to be OPERABLE in these MODES. Although the LCO for the UHS is not applicable in MODES 5 and 6, the capability of the UHS to perform its necessary related support functions may be required for OPERABILITY of supported systems.
ACTIONS	A.1 and A.2 With the SW temperature > 97ºF but ≤ 99ºF, the required cooling capacity of the SW System must be verified by evaluating the existing operational condition of the systems and components served by the SW System and verifying that each is capable of performing its safety related function. The required cooling capacity must also be re-verified once per 12 hours. In addition, the SW temperature must be verified ≤ 99ºF once per hour. The temperature verification ensures the SW temperature remains below the maximum water temperature allowed for the safety related components to perform their safety function.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

The Completion Time of Required Action A.1 was developed considering that some activities required to complete the evaluation of required cooling capacity could be completed prior to the Condition being entered.

The Completion Time of Required Action A.2 is based on shift schedules for convenience and is considered acceptable since temperature monitoring capability is available to detect an increase in SW temperature throughout the period of Condition A.

B.1 and B.2

If the Required Actions and associated Completion Times are not met or the UHS is inoperable for reasons other than Condition A, 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR verifies that adequate long term (22 day) cooling can be maintained. The specified level also ensures that sufficient NPSH is available to operate the SWS pumps. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This SR verifies that the UHS water level is ≥ 218 ft MSL.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.2

This SR verifies that the SWS is available to cool the CCW System to at least its maximum design temperature with the maximum accident or normal design heat loads for 30 days following a Design Basis Accident. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. This SR verifies that the service water temperature is ≤ 97ºF.

REFERENCES

1. UFSAR, Section 9.2.4.

2. UFSAR Section 2.4.6.1.

3. UFSAR Section 2.1.1.2.

4. NUREG-75/024, "Final Environmental Statement Related to the Operation of H. B. Robinson Nuclear Steam-Electric Plant Unit 2," U. S. Nuclear Regulatory Commission, Washington DC 20555, April 1975, page 3-7.

5. USGS Historical Daily Values for Station Number 02130900, Black Creek Near McBee, South Carolina, Years 1960-1993.

B 3.7 PLANT SYSTEMS

B 3.7.9 Control Room Emergency Filtration System (CREFS)

BASES

BACKGROUND

The CREFS provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke.

The CREFS is a subsystem of the Control Room Air Conditioning System and consists of redundant air cleaning unit fans, redundant air intake dampers and associated ductwork, redundant air recirculation fans and associated ductwork, redundant air exhaust dampers, a non-redundant air filtration unit housing, and non-redundant ductwork and gravity dampers. The necessary instrumentation is also considered a part of the system. The air filtration unit housing contains a prefilter, a high efficiency particulate air (HEPA) filter bank, and an activated charcoal adsorber section for removal of gaseous activity (principally iodines). A second bank of HEPA filters follows the adsorber section to collect carbon fines and provides backup in case of failure of the main HEPA filter bank.

The control room envelope (CRE) is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and may encompass other areas to which personnel access is necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations, and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the inleakage of unfiltered air into the CRE will not exceed the inleakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The CRE and its boundary are defined in the Control Room Envelope Habitability Program.

The CREFS is an emergency system, parts of which also operate during normal unit operations in the standby mode of operation. Upon receipt of the actuating signal(s), the stream of ventilation air is recirculated through the system filters. The prefilters remove any large particles in the air to prevent

(continued)

BASES

BACKGROUND (continued)

excessive loading of the HEPA filters and charcoal (continued) absorbers.

The CREFS is actuated to the emergency pressurization mode of operation on a safety injection signal. A single area radiation monitor also provides a signal to the CREFS to actuate emergency pressurization. Upon actuation, the air recirculation fans start and move recirculation air through the air cleaning unit filter train, and the control room exhaust to the outdoors is isolated.

The control room envelope is maintained under a positive differential pressure with respect to adjacent areas and the outdoors during the emergency pressurization mode of operation. A maximum makeup rate of 400 CFM is provided for pressurizing the control room envelope. Periodic testing is required to demonstrate that the control room is pressurized to a minimum of 0.125 inches water gage with respect to the outdoors, and to a positive pressure with respect to adjacent areas, with an outside air makeup rate of ≤ 400 CFM, while in the emergency pressurization mode of operation. Periodic testing also demonstrates that a positive pressure can be maintained in the control room with respect to the outdoors. The CREFS operation in maintaining the control room habitable is discussed in the Updated Final Safety Analysis Report (UFSAR), Section 6.4 (Ref. 1).

Pressurization of the Control Room habitability envelope by the CREFS assumes that non-safety related ventilation fans in the Auxiliary Building adjacent to the Control Room either remain in operation or cease operation. In the event that the air supply fan to the Auxiliary Building (HVS-1) remains in operation simultaneously with the Auxiliary Building air exhaust fan not in operation (HVE-7), areas adjacent to the Control Room could be slightly positive with respect to the Control Room. In-leakage testing and analyses have shown that the dose to the Control Room operator would be satisfactory under this condition (Ref. 2).

The air entering the control room through the outside air intake is continuously monitored for radiation in the control room and smoke in the ventilation air duct.

The CREFS is designed to maintain the control room environment for 30 days of continuous occupancy after a

(continued)

BASES

BACKGROUND (continued)	Design Basis Accident (DBA) without exceeding a 5 rem total (continued) effective dose equivalent (TEDE).

APPLICABLE SAFETY ANALYSES

The active CREFS components are arranged in redundant, safety related ventilation trains. The location of components and ducting within the CRE ensures an adequate supply of filtered air to all areas requiring access. The CREFS provides airborne radiological protection for the control room occupants, as demonstrated by the control room accident dose analyses for the design basis accidents.

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

The CREFS satisfies Criterion 3 of the NRC Policy Statement.

LCO

Two redundant CREFS trains are required to be OPERABLE to ensure that at least one is available if a single active failure disables the other train. Total system failure, such as from a loss of both ventilation trains or from an inoperable CRE boundary, could result in exceeding a dose of 5 rem TEDE to the CRE occupants in the event of a large radioactive release.

The CREFS is considered OPERABLE when the individual components necessary to limit operator exposure are OPERABLE in both trains. A CREFS train is OPERABLE when the air cleaning unit fan, air recirculation fan, air intake damper and associated ductwork, and air exhaust damper and associated ductwork, are operable for the given train. The common air filtration unit is OPERABLE to support either train in accordance with the Ventilation Filter Testing Program. In addition, non-redundant ductwork and gravity dampers are OPERABLE to support either train.

In order for the CREFS trains to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a radioactive release does not exceed the calculated dose in the licensing bases, and that CRE occupants are protected from hazardous chemicals and smoke.

(continued)

BASES

LCO (continued)

The LCO is modified by a Note allowing the CRE boundary to (continued) be opened intermittently under administrative control. This Note only applies to openings that can be rapidly restored to the design condition (e.g., doors, access panels). For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting. For other openings, the control will be proceduralized and consist of stationing an individual at the opening with continuous communication capability with operators in the CRE and the ability to rapidly close the opening and restore the CRE boundary to a condition equivalent to the design condition when the need is indicated.

APPLICABILITY

In MODES 1, 2, 3, 4, and during movement of irradiated fuel assemblies, CREFS must be OPERABLE to control occupant exposure during and following a DBA. Applicability to movement of irradiated fuel excludes movement of irradiated fuel within a properly sealed spent fuel shipping/storage cask.

ACTIONS

A.1

When one CREFS 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 CREFS train is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE CREFS train could result in loss of CREFS function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

B.1 and B.2

In MODE 1, 2, 3, or 4, if the inoperable CREFS 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

(continued)

ACTIONS (continued)

MODE 5 within 36 hours. The allowed Completion Times are (continued) reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

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

During movement of irradiated fuel assemblies, if the inoperable CREFS train cannot be restored to OPERABLE status within the required Completion Time, action must be taken to immediately place the OPERABLE CREFS train in the emergency pressurization mode. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that any active failure would be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that could result in a release of radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk. This does not preclude the movement of fuel to a safe position.

<u>D.1</u>

During movement of irradiated fuel assemblies, with two CREFS trains inoperable, action must be taken immediately to suspend activities that could result in a release of radioactivity that might enter the control room. This places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

<u>E.1</u>

If both CREFS trains are inoperable in MODE 1, 2, 3, or 4, for reasons other than an inoperable CRE boundary, action must be taken to restore OPERABLE status of at least one CREFS train within 48 hours. The 48 hour completion time is based upon the low probability of a DBA occurring during this time.

(continued)

ACTIONS (continued)

F.1 and F.2

In MODE 1, 2, 3, or 4, if both inoperable (for reasons other than an inoperable CRE boundary) CREFS trains 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.

G.1, G.2, and G.3

If the CRE boundary is inoperable as defined in the CRE Habitability Program, then 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 a reasonable time to diagnose, plan and possibly repair, and test most problems with the CRE boundary. Note that entry into Condition G does not preclude entry into

(continued)

BASES

ACTIONS (continued)

H.1

Conditions A or E for other reasons which may make one or more CREFS trains inoperable. Similarly, entry into Conditions A or E for reasons other than Condition G, does not preclude entry into Condition G at the same or later time.

In MODE 1, 2, 3, or 4, if the inoperable CRE boundary 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

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 minutes is adequate to demonstrate the function of the system. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.9.2

This SR verifies that the required CREFS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.9.3

This SR verifies that each CREFS train starts and operates on an actual or simulated actuation signal. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.7.9.4

This SR verifies the integrity of the CRE boundary. The CRE Habitability Program specifies administrative controls for temporary breaches to the boundary, preventative maintenance requirements to ensure the boundary is maintained, and leak test surveillance requirements. The details and frequencies for these requirements are specified in the CRE Habitability Program.

REFERENCES

1. UFSAR, Section 6.4.
2. UFSAR Section 6.4.2.3.
3. UFSAR, Chapter 15.
4. Deleted.

B 3.7 PLANT SYSTEMS

B 3.7.10 Control Room Emergency Air Temperature Control (CREATC)

BASES

BACKGROUND

The CREATC Water Cooled Condensing Units (WCCUs) are a subsystem of the Control Room Air Conditioning System and consist of the necessary redundant refrigeration equipment to maintain the control room temperature to ≤ 85ºF during normal operation and design basis accident conditions. The necessary instrumentation is also considered a part of the system. The system is arranged into two redundant trains that share only the Service Water System (SWS) supply to both trains.

The WCCUs are an emergency system, which also operate during normal unit operations. A single train will provide the required temperature control to maintain the control room ≤ 85ºF. The WCCU operation in maintaining the control room temperature is discussed in the UFSAR, Section 6.4 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the CREATC WCCUs is to maintain the control room temperature for continuous occupancy.

The active WCCU components are arranged in redundant, safety related trains. During emergency operation, the operating WCCU maintains the temperature ≤ 85ºF. A single active failure of a component of the system, 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 WCCUs are designed in accordance with Seismic Category I requirements. The WCCUs are 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 WCCUs satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES

LCO

Two independent and redundant trains of the CREAC WCCUs 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.

A WCCU train is OPERABLE when the refrigeration equipment of a particular train is capable of removing the design heat load. Implicit in the operability of the WCCU trains are the instrumentation and controls necessary to support automatic start and temperature control operation. Also implicit in the operability of the WCCU trains is the operability of the SWS supply to the WCCU subsystem.

APPLICABILITY

In MODES 1, 2, 3, 4, and during movement of irradiated fuel assemblies, WCCUs must be OPERABLE to ensure that the control room temperature will not exceed equipment operational requirements. Applicability to movement of irradiated fuel excludes movement of irradiated fuel within a properly sealed spent fuel shipping cask.

ACTIONS

A.1

With one WCCU train inoperable, action must be taken to restore OPERABLE status within 30 days. In this Condition, the remaining OPERABLE WCCU train is adequate to maintain the control room temperature within limits. However, the overall reliability is reduced because a single failure in the OPERABLE WCCU train could result in loss of cooling function. The 30 day Completion Time is based on the consideration that the remaining train can provide the required cooling.

B.1 and B.2

In MODE 1, 2, 3, or 4, if the inoperable WCCU 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

(continued)

ACTIONS

B.1 and B.2 (continued)

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, C.2.1, and C.2.2

During movement of irradiated fuel, if the inoperable WCCU train cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE WCCU train must be placed in operation immediately. This action ensures that the remaining train is OPERABLE, that no failures preventing automatic actuation will occur, and that active failures will be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that present a potential for releasing radioactivity that might require emergency pressurization of the control room. This places the unit in a condition that minimizes accident risk. This does not preclude the movement of fuel to a safe position.

D.1 and D.2

During movement of irradiated fuel assemblies, with two WCCU trains inoperable, action must be taken immediately to suspend activities that could result in a release of radioactivity that might require isolation of the control room. This places the unit in a condition that minimizes risk. This does not preclude the movement of fuel to a safe position.

E.1

If both WCCU trains are inoperable in MODE 1, 2, 3, or 4, action must be taken to restore at least one WCCU train to OPERABLE status within 48 hours. The 48 hour completion time is based upon the low probability of a Design Basis Accident occurring during this time.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

In MODE 1, 2, 3, or 4, if both inoperable WCCU trains 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.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

This SR verifies that the heat removal capability of the system is sufficient to remove the heat load assumed in the control room. This SR consists of a combination of testing and calculations. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 6.4.

B 3.7 PLANT SYSTEMS

B 3.7.11 Fuel Building Air Cleanup System (FBACS)

BASES

BACKGROUND

The FBACS filters airborne radioactive particulates from the area of the spent fuel pool following a fuel handling accident in the Fuel Building. The FBACS, in conjunction with other normally operating systems, also provides environmental control of temperature and humidity in the spent fuel pool area.

The FBACS is a single train system which consists of a heater, a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and a fan. Ductwork, valves or dampers, and instrumentation also form part of the system. The heaters are not required for OPERABILITY since the carbon laboratory tests are performed at 95% relative humidity, but are maintained in the system to provide additional efficiency margin.

The FBACS is a manually initiated system, which may also be operated during normal plant operations.

The FBACS is discussed in the UFSAR, Sections 6.5.1, 9.4.5, and 15.7.4 (Refs. 1, 2, and 3, respectively) because it may be used for normal, as well as post accident, atmospheric cleanup functions.

APPLICABLE SAFETY ANALYSES

The FBACS design basis is established by the consequences of the limiting Design Basis Accident (DBA), which is a fuel handling accident in the Fuel Building. The analysis of the fuel handling accident, given in Reference 3, assumes that all fuel rods in an assembly are damaged and the fission product inventory in the gap is released. The FBACS is assumed to be operating during the release and a once through filter efficiency of 90% for elemental iodine and 70% for organic iodine is assumed. All of the release passes through the FBACS due to the negative air pressure maintained by the FBACS in the Fuel Building, (i.e., no bypass leakage is assumed). The integrated dose is calculated using assumptions in Reference 3, which are consistent with the methodology utilized

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

in Regulatory Guide 1.183 (Ref. 8).

The FBACS satisfies Criterion 3 of the NRC Policy Statement.

LCO

The FBACS is required to be OPERABLE and operating. Total system failure could result in the atmospheric release from the fuel handling building exceeding the 10 CFR 50.67 (Ref. 4) limits in the event of a fuel handling accident.

The FBACS is considered OPERABLE when the individual components necessary to control exposure in the fuel handling building are OPERABLE. The FBACS is considered OPERABLE when its:

a. Fan is OPERABLE;

b. HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration function; and

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

APPLICABILITY

During movement of irradiated fuel in the fuel handling area, the FBACS is required to be OPERABLE and operating to alleviate the consequences of a fuel handling accident.

ACTIONS

A.1

When the FBACS is inoperable during movement of irradiated fuel assemblies in the fuel building, action must be taken to place the unit in a condition in which the LCO does not apply. Action must be taken immediately to suspend movement of irradiated fuel assemblies in the fuel building. This does not preclude the movement of fuel to a safe position.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

The FBACS should be checked periodically to ensure that it functions properly. As the environmental and normal operating conditions on this system are not severe, testing once every 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 controlled under the Surveillance Frequency Control Program.

SR 3.7.11.2

This SR verifies that the required FBACS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.11.3

This SR verifies the integrity of the fuel building enclosure. The ability of the fuel building to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the FBACS. The FBACS is designed to maintain a slight negative pressure in the fuel building, to prevent unfiltered LEAKAGE. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

ISTS SR 3.7.13.4 is modified by a Note. This Note provides clarification that the Surveillance is not applicable when the only movement of irradiated fuel is movement of a spent fuel shipping cask containing irradiated fuel. This Note is necessary to permit the shipping cask to be removed from the fuel handling building. When the side walls are opened to permit cask egress, ISTS SR 3.7.13.4 cannot be met.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.11.3 (continued)

OPERABILITY of the FBACS is not necessary when irradiated fuel assemblies are in a spent fuel shipping cask because irradiated fuel assemblies are protected from damage and associated release of fission products by the cask and other controls associated with shipments of spent fuel assemblies. The terms “shipping cask” and “shipment” used within this specification and bases also applies to the transfer cask/dry fuel storage container used to transfer fuel to the onsite Independent Spent Fuel Storage Installation (ISFSI).

REFERENCES

1. UFSAR, Section 6.5.1.

2. UFSAR, Section 9.4.5.

3. UFSAR, Section 15.7.4.

4. 10 CFR 50.67.

5. Deleted.

6. Licensee Event Report (LER) 50-26/97-05, dated May 22, 1997.

7. Deleted.

8. Regulatory Guide 1.183.

B 3.7 PLANT SYSTEMS

B 3.7.12 Fuel Storage Pool Water Level

BASES

BACKGROUND

The minimum water level of 21 ft above the top of the fuel in the fuel storage pool exceeds the assumptions of iodine decontamination factors following a fuel handling accident and bounds the sensible heat sink assumptions used in "time to boil" calculations. With the fuel storage racks installed in the spent fuel storage pool, a water level 21 ft above the fuel corresponds to approximately 35 ft pool water depth. The specified water level shields and minimizes the general area dose when the storage racks are filled to their maximum capacity. The water also provides shielding during the movement of spent fuel.

A general description of the fuel storage pool design is given in the UFSAR, Section 9.1.2 (Ref. 1). A description of the Spent Fuel Pool Cooling and Cleanup System is given in the UFSAR, Section 9.1.3 (Ref. 2). The assumptions of the fuel handling accident are given in the UFSAR, Section 15.7.4 (Ref. 3).

APPLICABLE SAFETY ANALYSES

The minimum water level in the fuel storage pool meets the assumptions of the fuel handling accident described in Reference 3. The resultant 2 hour thyroid dose per person at the exclusion area boundary is a small fraction of the 10 CFR 50.67 (Ref. 4) limits.

According to the fuel storage pool fuel handling accident analysis (Ref. 3), the minimum level of 21 ft over the top of irradiated fuel assemblies seated in the storage racks exceeds the submergence requirements necessary to obtain the assumed decontamination factor (DF) for inorganic iodines released from damaged fuel as a result of the accident.

The fuel storage pool water level satisfies Criterion 2 of the NRC Policy Statement.

LCO

The fuel storage pool water level is required to be ≥ 21 ft over the top of irradiated fuel assemblies seated in the

(continued)

B 3.7 PLANT SYSTEMS
BASES

LCO (continued)	storage racks. The specified water level preserves the assumptions of the fuel handling accident analysis (Ref. 3) and time to boil calculations (Ref. 2). As such, it is the minimum required for fuel movement within the fuel storage pool.
APPLICABILITY	This LCO applies during movement of irradiated fuel assemblies in the fuel storage pool, since the potential for a release of fission products exists.
ACTIONS	<u>A.1</u> Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. When the initial conditions for prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the fuel storage pool water level is lower than the required level, the movement of irradiated fuel assemblies in the fuel storage pool is immediately suspended to a safe position. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position. If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.
SURVEILLANCE REQUIREMENTS	<u>SR 3.7.12.1</u> This SR verifies sufficient fuel storage pool water is available in the event of a fuel handling accident. The water level in the fuel storage pool must be checked periodically.

(continued)

B 3.7 PLANT SYSTEMS
BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

During fuel transfer operations, the level in the fuel storage pool is in equilibrium with the refueling canal, and the level in the refueling canal is checked daily in accordance with SR 3.9.6.1.

REFERENCES

1. UFSAR, Section 9.1.2.
2. UFSAR, Section 9.1.3.
3. UFSAR, Section 15.7.4.
4. 10 CFR 50.67.

B 3.7 PLANT SYSTEMS

B 3.7.13 Fuel Storage Pool Boron Concentration

BASES

BACKGROUND

The fuel storage pool contains both low and high density racks racks for spent fuel storage. The low density spent fuel storage racks provide space for storage of 176 fuel assemblies and have a nominal 21-inch center-to-center spacing. The low density storage racks can accommodate new or spent fuel assemblies with initial enrichments up to 5 weight percent U^{235} (nominal 4.95 ± 0.05 weight percent). The high density spent fuel storage racks provide space for storage of 368 fuel assemblies with a nominal 10.5-inch center-to-center cell spacing. Additionally, the high density storage racks contain Boraflex on each cell wall face. No credit is taken for the Boraflex in criticality analyses due to the potential for degradation over time. The high density storage racks can accommodate new or spent fuel assemblies with initial enrichments up to 5 weight percent U^{235} (nominal 4.95 ± 0.05 weight percent), with restrictions on loading patterns and fuel burnup as specified in Section 9.1 of the UFSAR.

The water in the spent fuel storage pool normally contains a minimum of 1500 ppm soluble boron, which results in large subcriticality margins under actual operating conditions.

The effective neutron multiplication factor, K_{eff}, was calculated for the most conservative conditions of temperature, fuel enrichment, fuel spacing, structural poisoning, and other parameters (Ref. 1). For both the high density and low density spent fuel racks 5.0 w/o (4.95 w/o nominal) enrichment was assumed as the maximum permissible.

APPLICABLE SAFETY ANALYSE

Criticality analyses for the high density storage racks take credit for soluble boron at 1500 ppm in order to maintain K_{eff} less than or equal to 0.95.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

Accidents can be postulated that could increase the reactivity. For specific accidents, this increase in reactivity is unacceptable with unborated water in the storage pool. Thus, for these accidents, the presence of soluble boron in the storage pool prevents criticality. The postulated accidents are basically of two types. First, a fuel assembly could be incorrectly stored. Second, a fuel assembly could be dropped adjacent to the fully loaded storage rack. This could have a small positive reactivity effect. The negative reactivity effect of the soluble boron compensates for the increased reactivity caused by either one of the two postulated accident scenarios.

The concentration of dissolved boron in the fuel storage pool satisfies Criterion 2 of the NRC Policy Statement.

LCO

The fuel storage pool boron concentration is required to be $\geq$ 1500 ppm. The specified concentration of dissolved boron in the fuel storage pool preserves the assumptions used in the analyses of the potential criticality accident scenarios as described in Reference 1 and in maintaining $K_{eff} \leq 0.95$ in the high density storage racks. This concentration of dissolved boron is the minimum required concentration for fuel assembly storage and movement within the fuel storage pool.

APPLICABILITY

This LCO applies at all times. The criticality analyses for the high density storage racks take credit for the soluble boron in order to maintain K_{eff} less than or equal to 0.95. It is assumed the fuel will remain in the spent fuel pool until the end of the Operating License, therefore, the specified boron concentration must be maintained at all times.

BASES

ACTIONS

The Required Actions are modified by a Note indicating that

LCO 3.0.3 does not apply. The movement or storage of fuel in the spent fuel storage pool is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies or maintain the fuel storage pool boron concentration greater than 1500 ppm is not sufficient reason to require a reactor shutdown

A.1

When the concentration of boron in the fuel storage pool is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. Prior to resuming movement of fuel assemblies, the concentration of boron must be restored. This does not preclude movement of a fuel assembly to a safe position.

A.2

When the concentration of boron in the fuel storage pool is less than required, immediate action must be taken to return the concentration to the required limit to ensure K_{eff} remains less than or equal to 0.95 in the high density storage racks..

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

This SR verifies that the concentration of boron in the fuel storage pool is within the required limit. As long as this SR is met, the analyzed accidents and criticality analyses are fully addressed. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR Section 9.1.2.

B 3.7 PLANT SYSTEMS

B 3.7.14 New and Spent Fuel Assembly Storage

BASES

BACKGROUND

The new fuel storage racks are used for temporary storage capacity of 2/3 of the core inventory which is equivalent to 105 storage cells located on 21-inch centers. Of these 72 are available for fuel storage. The low density spent fuel storage racks provide space for storage of 176 fuel assemblies and have a nominal 21-inch center-to-center spacing. The high density spent fuel storage racks provide space for storage of 368 fuel assemblies with a nominal 10.5-inch center-to-center cell spacing. This capacity of 544 assemblies is equivalent to 3 1/3 cores.

The new fuel storage racks are normally maintained in a dry condition, i.e., the new fuel is stored in air. However, the NRC acceptance criteria (Ref. 2) for new fuel storage requires that the effective multiplication factor, k_{eff}, of the storage rack be no greater than 0.95 if accidentally flooded with pure water, and no greater than 0.98 if accidentally moderated with a low density hydrogenous material (optimum moderation). The new fuel storage racks have been analyzed for 5.0 w/o U235 enriched fuel for the full density flooding scenario and for the optimum moderation scenario (Ref. 3). The calculated worst-case keff for a full rack of 5.0 w/o U^{235} fuel does not meet the acceptance criteria stated above without the restrictions imposed on the storage configuration to prevent fuel from being placed in certain locations. For the fully flooded accident condition, the resulting k_{eff} is less than 0.95. The optimum moderation condition occurs at about 5 percent interspersed water volume and results in a k_{eff} of less than 0.98 (Ref. 1).

The low density region in the spent fuel storage pool is flooded with water borated to at least 1500 ppm. However, criticality analyses (Ref. 3) demonstrate that k_{eff} remains less than or equal to 0.95 in this region with no credit taken for the dissolved boron. There are no restrictions on storage locations except that no empty fuel rod locations are permitted in fuel assemblies with enrichment greater than 4.25 weight percent U^{235}.

(continued)

BASES

BACKGROUND (continued)	The high density region in the spent fuel storage pool is flooded with water borated to at least 1500 ppm. This region includes Boraflex neutron absorber material in the cell walls. However, no credit is taken for the Boraflex in criticality analyses (Ref. 4). The analyses assume water in the locations where Boraflex has been installed. The criticality analyses demonstrate that, should the concentration of dissolved boron go to zero, k_{eff} will remain less than 1.0. Taking credit for the dissolved boron results in a k_{eff} less than or equal to 0.95. In order to ensure the calculated k_{eff} criteria are met, there are loading restrictions in the high density racks. The details of these restrictions are given in Section 9.1 of the UFSAR, which specifies acceptable loading patterns as a function of enrichment and burnup.
APPLICABLE SAFETY ANALYSES	By closely controlling the manufacture of each fuel assembly, by controlling the movement of each fuel assembly, and by checking the location of each fuel assembly after movement, the potential for an inadvertent criticality becomes very small. The restrictions on fuel location are designed to ensure the assumptions of the criticality analyses of References 3 and 4 are met. The configuration of fuel assemblies in the new and spent fuel storage racks satisfies Criterion 2 of the NRC Policy Statement.
LCO	The restrictions on the placement of fuel assemblies within the new and spent fuel storage racks ensures the k_{eff} of the stored fuel will always remain within the criteria of Section 4.3.1.1 of these Technical Specifications. The approved storage locations for fuel are identified in the fuel storage requirements contained in Updated Final Safety Analysis Report (UFSAR) Section 9.1 (Ref. 1).
APPLICABILITY	This LCO applies whenever any fuel assembly is stored in the new or spent fuel storage racks.

(continued)

BASES (continued)

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. When the configuration of fuel assemblies stored in the new and spent fuel storage racks is not in accordance with UFSAR Section 9.1, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with UFSAR Section 9.1.

If unable to move irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If unable to move irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the action is independent of reactor operation. Therefore, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1

This SR verifies by administrative means that fuel assembly storage is in accordance with UFSAR Section 9.1.

REFERENCES1.

1. UFSAR Section 9.1.
2. NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," July 1987.
3. EMF-94-113, "H. B. Robinson New and Spent Fuel Criticality Analysis," Siemens Power Corporation, July 1994 (transmitted to NRC by CP&L letter dated July 28, 1994).
4. Holtec International Report HI-992350, "Criticality Safety Analyses of the Robinson Spent Fuel Racks with Loss of Boraflex," Revision 3.

BASES

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B 3.7 PLANT SYSTEMS

B 3.7.15 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, iodine spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

The Steam Generator Tube Rupture (SGTR) and the Main Steam Line Break (MSLB) (Ref. 1) result in the release of activity contained in the secondary side.

With the specified activity limit, the resultant offsite doses will be less than the limits of 10 CFR 50.67.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The accident analyses of the SGTR and the MSLB, as discussed in Reference 1, assume the initial secondary coolant specific activity to be at the LCO concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analyses for determining the radiological consequences of the postulated accidents. The accident analyses, based on this and other assumptions, shows that the radiological consequences of the accidents do not exceed the limits of 10 CFR 50.67 (Ref. 2).

With the loss of offsite power, the remaining steam generators are available for core decay heat dissipation by venting steam to the atmosphere through the Main Steam Safety Valves (MSSVs) and steam generator power operated relief valves (PORVs). The Auxiliary Feedwater System supplies the necessary makeup to the steam generators. Steaming via the unaffected steam generators continues until the reactor coolant temperature and pressure have decreased sufficiently for the Residual Heat Removal System to complete the cooldown.

Secondary specific activity limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

As indicated in the Applicable Safety Analyses, the specific activity of the secondary coolant is required to be ≤ 0.10 μCi/gm DOSE EQUIVALENT I-131 to limit the radiological consequences of a Design Basis Accident (DBA) to less than the required limit (Ref. 2).

(continued)

BASES

LCO (continued)	Monitoring the specific activity of the secondary coolant ensures that when secondary specific activity limits are exceeded, appropriate actions are taken in a timely manner to place the unit in an operational MODE that would minimize the radiological consequences of a DBA.
APPLICABILITY	In MODES 1, 2, 3, and 4, the limits on secondary specific activity apply due to the potential for secondary steam releases to the atmosphere. In MODES 5 and 6, the steam generators are not being used for heat removal. Both the RCS and steam generators are depressurized, and primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.
ACTIONS	<u>A.1 and A.2</u> DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant, is an indication of a problem in the RCS and contributes to increased post accident doses. If the secondary specific activity cannot be restored to within limits 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.
SURVEILLANCE REQUIREMENTS	<u>SR 3.7.15.1</u> This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131, confirms the validity of the safety analysis assumptions as to the source terms in post accident releases. It also serves to identify and trend any unusual

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1 (continued)

isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 15.
2. 10 CFR 50.67.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

BASES

BACKGROUND

The unit AC Electrical Power Distribution System AC sources consist of the offsite power sources (preferred power sources), and the onsite standby power sources (Train A and Train B diesel generators (DGs)). As required by HBRSEP design criteria (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 emergency 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.

Offsite power is supplied to the unit switchyard(s) from the transmission network by multiple transmission lines. From the switchyard(s), two electrically and physically separated circuits provide AC power, through two dedicated startup transformers, to the 480 V ESF buses E1 and E2. Both startup transformers are provided with a load tap changer. These load tap changers provide voltage regulation in the event of changing switchyard system voltage. Both load tap changers can be operated in manual or automatic modes. The 480 V ESF bus E1 is normally powered from the 115 kV switchyard through the dedicated 115 kV startup transformer, 4.16 kV bus 6 and station service transformer 2F. The 480 V ESF bus E2 is normally powered from the dedicated 230 kV startup transformer, 4.16 kV bus 9 and station service transformer 2G. The 4.16 kV buses 1, 2, 4 and 5 are powered from the main generator via the auxiliary transformer and 4.16 kV bus 3 is powered from the 115 kV startup transformer via 4.16 kV bus 8. Following a generator lockout, 4.16 kV buses 1 and 2 would automatically transfer to the 230 kV startup transformer via 4.16 kV bus 7 and 4.16 kV buses 4 and 5 would automatically transfer to the 115 kV startup transformer via 4.16 kV bus 8. Upon a loss of either startup transformer, ESF bus E1 would be powered from the main generator through the auxiliary transformer and 4.16 kV bus 2 via a manual transfer. Upon a loss of the 230 kV startup transformer, ESF bus E2 would be manually transferred to the 115 kV startup transformer via 4.16 kV bus 3.

(continued)

BASES

BACKGROUND (continued)

The unit auxiliary transformer is capable of supplying power to the onsite distribution system by back-feeding the main transformer from the 230 kV switchyard in the event that both startup transformers are out of service. Prior to back-feeding the main transformer from the 230 kV switchyard, the generator must be disconnected from the main transformer by removing the connecting straps. The main transformer back-feeding will only be done during MODES 5 or 6 unless nuclear safety considerations require it to be done during MODES 3 or 4 (in accordance with applicable Required Actions) when no other offsite power sources are available. A detailed description of the offsite power network and the circuits to the ESF buses is found in the UFSAR, Chapter 8 (Ref. 2).

An 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 ESF buses. This includes the circuit path from the 115 kV switchyard up to and including the feeder breakers to ESF bus E1 via the 115 kV startup transformer and station service transformer 2F and the circuit path from the 230 kV switchyard up to and including the feeder breakers to ESF bus E2 via the 230 kV startup transformer and station service transformer 2G.

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 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 480 V ESF bus is a dedicated emergency DG. DGs A and B are dedicated to ESF buses E1 and E2, respectively. A DG starts automatically on a safety injection (SI) signal (e.g., 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. 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, an undervoltage signal strips nonpermanent 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.

(continued)

BASES

BACKGROUND (continued)

In the event of the 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. Within 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.

The continuous service rating of each DG is 2500 kW with 10% overload permissible for up to 2 hours in any 24 hour period. Operation above the continuous service rating for longer than that time period is not allowed. Additionally, operation above the short-term overload limit (i.e., 2750 KW) is not allowed. The ESF loads that are powered from the 480 V 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; or

b. An assumed loss of offsite AC power and a worst case single active failure.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The AC sources satisfy Criterion 3 of NRC Policy Statement.

LCO

Two qualified circuits between the offsite transmission network and the onsite Electrical Power System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

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

The 115 kV to 4.16 kV startup transformer and the 230 kV to 4.16 kV startup transformer must both be in service as well as 4.16 kV buses 6 and 9. The remainder of the offsite circuit from the 4.16 kV buses 6 and 9 to the 480 V buses E1 and E2 must be energized.

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

Offsite circuit #1 consists of the 115 kV startup transformer (including the load tap changer in the automatic or manual mode of operation), which is supplied from the 115 kV switchyard, and is fed through 4.16 kV breaker 52-36 powering station service transformer 2F, which, in turn, powers ESF bus E1 through its normal feeder breaker. Offsite circuit #2 consists of the 230 kV startup transformer (including the load tap changer in the automatic or manual mode of operation), which is supplied from the 230 kV switchyard, and is fed through 4.16 kV breaker 52-47 powering station service transformer 2G, which, in turn, powers ESF bus E2 through its normal feeder breaker. In instances where the main generator output is connected to the transmission system with one offsite circuit (startup transformer) out of service, the load tap changer for the operable offsite circuit (startup transformer) must remain in automatic. Maintaining the load tap changer in automatic prevents the possibility of switching the operable load tap changer to manual with an undesired initial setting.

(continued)

BASES

LCO (continued)

Each emergency DG must be capable of starting, accelerating to rated speed and voltage (within the tolerances specified in the associated surveillances), and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the 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. Additionally, for a DG to be considered OPERABLE, the following protective trips must be bypassed to prevent a governor shutdown:

a. Low lube oil pressure

b. Low coolant pressure

c. High coolant temperature

d. High crankcase pressure

e. Start failure - governor shutdown

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources in one train are separate and independent (to the extent possible) of the AC sources in the other train. For the DGs, separation and independence are complete.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources - Shutdown."

(continued)

BASES

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 specific 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 offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two 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. Single train systems, such as turbine driven auxiliary feedwater pumps, may not be included.

The Completion Time for Required Action A.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. The train has no offsite power supplying it loads; and

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

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

(continued)

BASES

ACTIONS (continued)

Discovering no offsite power to one train of the onsite emergency 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 circuit and DGs are adequate to supply electrical power to Train A and Train B of the onsite emergency 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. 9), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite emergency Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 7 days. This could lead to a total of 10 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 7 days (for a total of 17 days) allowed prior to complete restoration of the LCO. The 10 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. .

(continued)

BASES

ACTIONS (continued)

Times

This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hours and 10 day Completion Times means that both Completion apply simultaneously, and the more restrictive Completion Time must be met.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

B.1

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the 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.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related trains. This includes motor driven auxiliary feedwater pumps. Single train systems, such as turbine driven auxiliary feedwater pumps, are not included. Redundant required feature failures consist of inoperable features associated with a train, redundant to the train that has an inoperable DG.

The Completion Time for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

(continued)

BASES

ACTIONS (continued)

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

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

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 offsite circuits are adequate to supply electrical power to the onsite Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.3.1, B.3.2.1, and B.3.2.2

Required Action B.3.1 requires performing SR 3.8.1.2 for the OPERABLE DG within 24 hours. This action is required to confirm the remaining DG remains OPERABLE.

Required Action B.3.2.1 provides an allowance to avoid unnecessary testing of the OPERABLE DG. 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 within 24 hours. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition D of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is

(continued)

BASES

ACTIONS (continued)

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.

If it is verified within 24 hours that the OPERABLE DG is not inoperable due to common cause failure, SR 3.8.1.2 need not be performed within 24 hours. However, it is still necessary to verify the OPERABILITY of the OPERABLE DG within 96 hours. Testing the OPERABLE DG more than once during the 7 day Completion Time is not required.

A NOTE has been added to take exception to perform REQUIRED ACTION B.3.2.2 and associated COMPLETION TIME for a DG intentionally removed from service solely for the reasons of performing pre-planned maintenance or SURVEILLANCE testing because no identified DG failure has occurred and the likelihood of the OPERABLE DG having an undetected failure is low. This exception is acceptable since the cause of the inoperable DG is known and is not related to correcting a DG failure mechanism (i.e., corrective maintenance) causing the DG to be inoperable when entering CONDITION B.

If a DG failure mechanism is identified at any time during preventative maintenance, corrective maintenance or during testing, REQUIRED ACTION B.3.1 or B.3.2 must be reentered for the OPERABLE DG. If the COMPLETION TIME commencing at the time the LCO was initially not met has expired, then the COMPLETION TIME commences from the time of the discovery of any failure mechanism that is identified during maintenance or testing of the inoperable DG. This allows an exception to the normal "time zero" for beginning a new COMPLETION TIME "clock." In this instance, the COMPLETION TIME "time zero" is specified as commencing at the time the failure mechanism is identified, instead of at the time the associated CONDITION was entered. REQUIRED ACTION B.3.1 or B.3.2, performance of SR 3.8.1.2 for the OPERABLE DG, need not be performed if it has been successfully performed within the previous 24-hours, or if it is currently operating. Performance of SR 3.8.1.2 within the previous 24-hours meets the intent of REQUIRED ACTION B.3.1 or B.3.2 by providing reasonable assurance that the OPERABLE DG will perform its associated safety function.

(continued)

BASES

ACTIONS (continued)

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

According to Generic Letter 84-15 (Ref. 6), 24 hours is reasonable to confirm that the OPERABLE DG(s) is not affected by the same problem as the inoperable DG.

B.4

Operation may continue in Condition B for a period that should not exceed 7 days.

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Distribution System. The 7 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.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet he LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 10 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 72 hours (for a total of 13 days) allowed prior to complete restoration of the LCO. The 10 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 7 day and 10 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

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

(continued)

BASES

ACTIONS (continued)

C.1 and C.2

Required Action C.1, which applies when two 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 features. 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. 9) 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 C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal “time zero” for beginning the allowed outage time “clock.” In this Required Action the Completion Time only beings on discovery that both:

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 9), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe that other combinations of two

(continued)

BASES

ACTIONS (continued)

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 9, 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.

<u>D.1 and D.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 D are modified by a Note to indicate that when Condition D is entered with no AC source to any train, the Conditions and Required Actions for LCO 3.8.9, “Distribution Systems - Operating,” must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one 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. 9), operation may continue in Condition D for a period that should not exceed 12 hours.

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system.

(continued)

ACTIONS (continued)

Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

E.1

With Train A and Train B DGs inoperable, there are no remaining standby AC sources. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 9, with both DGs inoperable, operation may continue for a period that should not exceed 2 hours.

F.1 and F.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the 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 without challenging plant systems.

(continued)

BASES

ACTIONS (continued)

G.1

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

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BASES

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 HBRSEP Design Criteria (Ref. 1). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are consistent with the recommendations of Regulatory Guide 1.137 (Ref. 6), as 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 467 V is 97% of the nominal 480 V output voltage. It 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 493 V is within the maximum operating voltage specified for the motors supplied by the 480 V subsystem. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 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 consistent with the recommendations given in Regulatory Guide 1.9 (Ref. 7).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supplies 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. The Surveillance Frequency 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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.

For the purposes of SR 3.8.1.2 and SR 3.8.1.7 testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

In order to reduce stress and wear on diesel engines, the 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 10 seconds. The minimum voltage and frequency stated in the SR are those necessary to ensure the DG can accept DBA loading while maintaining acceptable voltage and frequency levels. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, HBRSEP Unit No. 2 will monitor and trend the actual time to reach steady state operation as a means of assuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. The 10 second start requirement supports the assumptions of the design basis LOCA analysis in the UFSAR, Chapter 15 (Ref. 4).

The 10 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 10 second start requirement of SR 3.8.1.7 applies.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Since SR 3.8.1.7 requires a 10 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This is the intent of Note 1 of SR 3.8.1.2.

The Surveillance Frequencies are 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 approximating the design rating of the DGs. 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 a physical limitation. 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 controlled under the Surveillance Frequency Control Program.

This SR is modified by five 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. Note 5 to this SR permits removal of the bypass for protective trips after the DG has properly assumed its loads on the bus. This reduces exposure of the DG to undue risk of damage that might render it inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 specified is 140 gallons, which is approximately equal to 1/2 full, and is selected to ensure adequate fuel oil for a minimum of 35 minutes of DG operation at full load plus 10%.

The Surveillance Frequency 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 provides data regarding the watertight integrity of the fuel oil system. This SR is for preventative maintenance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from the storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.7

See SR 3.8.1.2.

SR 3.8.1.8

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 the overspeed trip.

For this unit, the single load for each DG is a safety injection pump rated at 380 Brake Horsepower. 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.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. The reason for Note 1 is that during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. In order to ensure that the DG is tested under load conditions that are as close to design basis conditions as possible, Note 2 requires that, if synchronized to offsite power, testing must be performed using a power factor ≤ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.9

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 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The requirement to verify the connection and power supply of permanent and auto connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, emergency Core Cooling Systems (ECCS) injection valves are not required 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 controlled under the Surveillance Frequency Control Program.

This SR is modified by three 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

Note 3 to this SR permits removal of the bypass for protective trips after the DG has properly assumed its loads on the bus. This reduces exposure of the DG to undue risk of damage that might render it inoperable.

SR 3.8.1.10

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis actuation signal (LOCA signal) and operates for ≥ 5 minutes. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, HBRSEP Unit No. 2 will monitor and trend the actual time to reach steady state operation as a means of assuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. The 5 minute period provides sufficient time to demonstrate stability. SR 3.8.1.10.d and SR 3.8.1.10.e ensure that permanently connected loads and emergency loads are energized from the offsite electrical power system on an ESF signal without loss of offsite power.

The requirement to verify the connection of permanent 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, ECCS injection valves are not required to be stroked open, or high pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by three 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 during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. Note 3 to this SR permits removal of the bypass for protective trips after the DG has properly assumed its loads on the bus. This reduces exposure of the DG to undue risk of damage that might render it inoperable.

SR 3.8.1.11

This Surveillance demonstrates that DG noncritical protective functions (e.g., high coolant water temperature) are bypassed. A manual switch is provided which bypasses the non-critical trips. The noncritical trips are normally 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. This SR is satisfied by simulating a trip signal to each of the non-critical trip devices and observing the DG does not receive a trip signal.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.12

This SR requires demonstration that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 1.75 hours of which is at a load equivalent to 110% of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG. The DG start shall be a manually initiated start followed by manual synchronization with other power sources. Additionally, the DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor of ≤ 0.9. 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 controlled under the Surveillance Frequency Control Program.

This Surveillance is modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the power factor limit will not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. Note 3 to this SR permits removal of the bypass for protective trips after the DG has properly assumed its loads on the bus.

This reduces exposure of the DG to undue risk of damage that might render it inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.13

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, HBRSEP Unit No. 2 will monitor and trend the actual time to reach steady state operation as a means of assuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable. The Surveillance Frequency 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 2 hours at full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all DG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.14

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 ± 0.5 seconds load sequence time setpoint tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

The Surveillance Frequency 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.

SR 3.8.1.15

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 3.8.1.9, 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 controlled under the Surveillance Frequency Control Program.

This SR is modified by three 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. Note 3 to this SR permits removal of the bypass for protective trips after the DG has properly assumed its loads on the bus. This reduces exposure of the DG to undue risk of damage that might render it inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.16

Transfer of the 4.160 kV bus 2 power supply from the auxiliary transformer to the start up transformer demonstrates the OPERABILITY of the offsite circuit network to power the shutdown loads. In lieu of actually initiating a circuit transfer, testing that adequately shows the capability of the transfer is acceptable. This transfer testing may include any sequence of sequential, overlapping, or total steps so that the entire transfer sequence is verified. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. The reason for Note 1 is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems. As stated in Note 2, automatic transfer capability to the SUT is not required to be met when the associated 4.160 kV bus and Emergency Bus are powered from the SUT. This is acceptable since the automatic transfer capability function has been satisfied in this condition.

SR 3.8.1.17

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. Stable operation at the nominal voltage and frequency values is also essential to establishing DG OPERABILITY, but a time constraint is not imposed. This is because a typical DG will experience a period of voltage and frequency oscillations prior to reaching steady state operation if these oscillations are not damped out by load application. This period may extend beyond the 10 second acceptance criteria and could be a cause for failing the SR. In lieu of a time constraint in the SR, HBRSEP Unit No. 2 will monitor and trend the actual time to reach steady state operation as a means of assuring there is no voltage regulator or governor degradation which could cause a DG to become inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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.

SR 3.8.1-18

Transfer of the ESF bus E1 power supply from 4.16 kV bus 6 to 4.16 kV bus 2 and transfer of the ESF bus E2 power supply from 4.16 kV bus 9 to 4.16 kV bus 3 demonstrates the OPERABILITY of the alternate circuit distribution network to power shutdown loads. The 18 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, unit safety systems.

(continued)

BASES

REFERENCES

1. UFSAR, Section 3.1.

2. UFSAR, Chapter 8.

3. UFSAR, Chapter 6.

4. UFSAR, Chapter 15.

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

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

7. Regulatory Guide 1.9, Rev. 3, July 1993.

8. Deleted.

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

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources - Shutdown

BASES

BACKGROUND

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

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that:

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

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

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in

(continued)

BASES

APPLICABLE SAFETY ANNALYSES (continued)

recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

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

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

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

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

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

The AC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

One offsite circuit capable of supplying the onsite power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems - Shutdown" ensures that all required loads are powered from offsite power. An OPERABLE DG, associated with the distribution system train required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Together, OPERABILITY of the required

(continued)

BASES

LCO (continued)

offsite circuit and DG ensures the availability of sufficient AC sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

The qualified offsite circuit must be capable of maintaining rated frequency and voltage within limits, and accepting required loads during an accident, while connected to the Engineered Safety Feature (ESF) bus(es). Qualified offsite circuits are those that are described in the UFSAR and are part of the licensing basis for the unit.

The DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. The DG must be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the 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 at ambient conditions.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

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

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

(continued)

BASES

APPLICABILITY (continued)

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

Applicability to movement of irradiated fuel excludes movement of irradiated fuel within a properly sealed spent fuel shipping cask.

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1.

ACTIONS

A.1

An offsite circuit would be considered inoperable if it were not available to one required ESF train. Although two trains are required by LCO 3.8.10, the one train with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By the allowance of the option to declare required features inoperable, with the circuit inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCO's ACTIONS.

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

With the offsite circuit not available to all required trains, the option would still exist to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required DG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or 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 required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration,

(continued)

BASES

ACTIONS

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

but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

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

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

Pursuant to LCO 3.0.6, the Distribution System's ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, the ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit, whether or not a train is de-energized. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a de-energized train.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, 3, and 4. SR 3.8.1.16 and 3.8.1.18 are not required to be met since only one offsite circuit is required to be OPERABLE. SR 3.8.1.17 is excepted because

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1 (continued)

starting independence is not required with the DG(s) that is not required to be operable.

This SR is modified by a Note. The reason for the Note is to minimize the frequency of requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to minimize the frequency of deenergizing a required 480 V ESF bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil and Starting Air

BASES

BACKGROUND

The diesel generators (DG) are provided with a fuel oil storage capacity sufficient to operate one diesel for a period of 7 days while the DG is supplying full load. This onsite fuel oil capacity is sufficient to operate the DGs for longer than the time to replenish the onsite supply from outside sources.

A 275 gallon day tank is located at each of the units. The level in the day tanks is maintained by two electric motor driven transfer pumps taking suction on the 25,000 gallon storage tank. A minimum of 34,000 gallons of fuel oil is maintained on site. This is sufficient to operate one diesel at full load for seven days.

Additional supplies of diesel oil are available in the Hartsville area and from port terminals at Charleston, SC, Wilmington, NC, Fayetteville, NC and Raleigh, NC. Ample trucking facilities exist to assure deliveries to the site within eight hours. Diesel fuel is also available from the internal combustion turbine diesel fuel oil storage tanks (approximately 95,000 gallon total capacity) located at the site and connections are provided for fuel oil transferral to the Unit 2 diesel fuel oil storage tank.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. The Diesel Fuel Oil Testing Program provides appropriate testing requirements for DG fuel oil. The fuel oil properties governed by these SRs are the water and sediment content, cloud point, viscosity, and specific gravity (or API gravity).

Each DG has an air start system with adequate capacity for eight successive start attempts on the DG without recharging the air start receiver(s).

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1), and in the UFSAR, Chapter 15 (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

Since diesel fuel oil and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of the NRC Policy Statement.

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation. It is also required to meet specific standards for quality. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown."

The starting air system is required to have a minimum capacity for eight successive DG start attempts without recharging the air start receivers.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil, and the starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil and starting air are

(continued)

BASES

APPLICABILITY (continued)	required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

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

A.1 and B.1

In these Conditions, the 7 day fuel oil supply for a DG is not available. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. These circumstances may be caused by events, such as full load operation required after an inadvertent start while at minimum required level, or feed and bleed operations, which may be necessitated by increasing particulate levels or any number of other oil quality degradations. This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of fuel oil to the Unit 2 DG fuel oil tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring the DGs inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

C.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.2 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration

(continued)

BASES

ACTIONS

C.1 (continued)

may involve feed and bleed procedures, filtering, or combinations of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that the DG would still be capable of performing its intended function.

D.1

With starting air receiver pressure < 210 psig, sufficient capacity for eight successive DG start attempts does not exist. However, as long as the receiver pressure is > 150 psig, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

E.1

With a Required Action and associated Completion Time not met, or one or more DG's fuel oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through D, the associated DGs may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

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

(continued)

BASES

SURVEILLANCE REQURIEMENTS

SR 3.8.3.1 (continued)

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.3.2

The tests listed in the Diesel Fuel Oil Testing Program (API or Specific Gravity, Cloud Point, Water and Sediment, and Viscosity) are a means of determining whether fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil is acceptable for use. New fuel oil received for storage in the Unit 1 I-C turbine fuel oil storage tank and subsequently transferred to the Unit 2 DG fuel oil storage tank is verified to meet the limits below prior to adding to the Unit 1 I-C storage tanks either by verifying the integrity of the seal on the tank truck against the certificate of compliance or by testing of the fuel oil on the truck prior to transfer. Additionally, stored fuel in the Unit 1 I-C storage tank and in the Unit 2 DG fuel oil storage tank is tested every 31 days. The sampling methodology, tests, and limits are as follows:

a. Sampling of the vertical IC Turbine tanks is performed by recirculating the tanks and sampling at the Unit 1 transfer pump discharge. Sampling of the Unit 2 DG fuel oil storage tank is performed from the discharge from the fuel oil storage tank transfer pump (Ref.3); and

b. Verify in accordance with applicable ASTM standards that the sample has an API gravity of ≥ 28, a Saybolt viscosity at 100ºF of ≥ 32 SUS and ≤ 50 SUS, water and sediment ≤ 0.10%, and cloud point ≤ 10ºF.

Failure to meet any of the limits except cloud point is cause for rejecting the fuel oil. Cloud point will be managed by the Diesel Fuel Oil Testing Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.3

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of eight engine start cycles without recharging. The pressure specified in this SR is intended to reflect the lowest value at which the eight starts can be accomplished.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.3.4

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 Unit 2 DG fuel storage tank eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, and contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 15.

3. CP&L Letter to NRC dated November 20, 1981, "Quality Assurance Requirements Regarding Diesel Generator Fuel Oil."

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources - Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment and preferred AC instrument bus power (via inverters). As required by HBRSEP Design Criteria (Ref.1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single active failure.

The 125 VDC electrical power system consists of two separate and redundant safety related DC electrical power subsystems (Train A and Train B). Each subsystem consists of one station 125 VDC battery, one primary (in service) battery charger for the battery, and all the associated control equipment and interconnecting cabling.

Two 100% capacity battery chargers are installed to support system operation. One charger is designated as the in service unit and the other is designated as the standby unit, which provides backup service in the event that the in service battery charger is out of service. If the standby battery charger is substituted for one of the in service battery chargers, then the requirements of redundancy between subsystems are maintained.

During normal operation, the 125 VDC load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal AC power to the battery charger, the battery charger trips and the DC load is automatically powered from the station batteries. The in service unit automatically restarts and the standby unit requires a manual restart when power is restored. The manual restart is required due to capacity margin associated with the EDG.

The Train A and Train B DC electrical power subsystems provide the control power for its associated AC power load group, 4.16 kV switchgear (buses 1, 2, 3 and 4), and 480 V breakers. The DC electrical power subsystems also provide DC electrical power to the inverters, which in turn power four of the eight instrument buses.

(continued)

BACKGROUND (continued)

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution System - Operating," and LCO 3.8.10, "Distribution Systems - Shutdown."

Each battery has adequate storage capacity to carry the required load continuously for at least 1 hour following a plant trip and a loss of all AC power (Ref. 2).

There is no sharing between redundant subsystems, such as batteries, battery chargers, or distribution panels.

The battery for Train A DC electrical power subsystem is sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. Battery size is based on 125% of required capacity and, after selection of an available commercial battery, resulted in an initial battery capacity in excess of 150% of required capacity. The battery for Train B DC electrical power subsystem is sized to produce required capacity at 91% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. Battery size is based on 110% of required capacity and, after selection of an available commercial battery, resulted in an initial battery capacity in excess of 128% of required capacity. The voltage limit is 2.13 V per cell, which corresponds to a total minimum voltage output of 128 V per battery.

Each Train A and Train B DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger also has sufficient capacity to restore the battery from a partial discharge condition to its fully charged state within 24 hours while supplying normal steady state loads discussed in the UFSAR, Chapter 8 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 3), and in the UFSAR, Chapter 15 (Ref. 4), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC

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APPLICABLE SAFETY ANALYSES (continued)	electrical power for the DGs, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the DC sources OPERABLE during accident conditions in the event of: a. An assumed loss of all offsite AC power or all onsite AC power; or b. An assumed loss of offsite power and a worst case single active failure. The DC sources satisfy Criterion 3 of the NRC Policy Statement.
LCO	The DC electrical power subsystems, each subsystem consisting of one battery, battery charger and the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the train are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any train DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4). An OPERABLE DC electrical power subsystem requires the battery and one of the two associated chargers to be operating and connected to the associated DC bus(es).
APPLICABILITY	The DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that: a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and b. Adequate core cooling is provided, and containment integrity and other instrument functions are

(continued)

APPLICABILITY (continued)

maintained in the event of a postulated DBA. The DC electrical power requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.5, "DC Sources - Shutdown and During Movement of Irradiated Fuel Assemblies."

ACTIONS

A.1

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

If one of the required DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger(s), or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystem has the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single active failure would, however, result in the complete loss of the remaining 125 VDC electrical power subsystems with attendant loss of ESF functions, continued power operation should not exceed 2 hours. The 2 hour Completion Time reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

B.1 and B.2

If the inoperable DC electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the

(continued)

ACTIONS

B.1 and B.2 (continued)

required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or a battery cell) in a fully charged state. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the initial voltages assumed in the battery sizing calculations and permit a single battery cell to be jumpered out. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.2

Visual inspection of the battery cells, cell plates, and battery racks provides an indication of physical damage or abnormal deterioration that could potentially degrade battery performance.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.3

Visual inspection of intercell, intertier, and terminal connections provide an indication of physical damage or abnormal deterioration that could indicate degraded battery condition. The anticorrosion material is used to help ensure good electrical connections and to reduce terminal deterioration. The visual inspection for corrosion is not intended to require removal of and inspection under each

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.4.3 (continued)

terminal connection. The removal of visible corrosion is a preventive maintenance SR. The presence of visible corrosion does not necessarily represent a failure of this SR provided visible corrosion is removed during performance of SR 3.8.4.3.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.4

This SR requires that each battery charger be capable of supplying 300 amps and 125 V for ≥ 4 hours. These current and voltage requirements are based on the design capacity of the chargers. The battery charger supply is based on normal DC loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state. The minimum required amperes and duration ensures that these requirements can be satisfied.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.4.5

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.4.5 (continued)

The reason for Note 2 is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

SR 3.8.4.6

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

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.6; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of SR 3.8.4.5.

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

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

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.4.6 (continued)

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 5). This reference recommends that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery rate of deterioration is increasing, even if there is ample capacity to meet the load requirements. An acceptance criterion of 80% of rated capacity is applicable to the "A" battery only. An acceptance criterion of 91% is applicable to the "B" battery since the battery's capacity is not as great.

The Surveillance Frequency 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 perturb the electrical distribution system and challenge safety systems.

REFERENCES

1. UFSAR Section 3.1.
2. UFSAR, Chapter 8.
3. UFSAR, Chapter 6.
4. UFSAR, Chapter 15.
5. IEEE-450-1995.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources - Shutdown

BASES

BACKGROUND

A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum DC electrical power sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that:

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

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

c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

The DC sources satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASE (continued)

LCO

The DC electrical power subsystems, each subsystem consisting of one battery or a battery charger, and the corresponding control equipment and interconnecting cabling within the train, are required to be OPERABLE to support required trains of the distribution systems required OPERABLE by LCO 3.8.10, "Distribution Systems - Shutdown." This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

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

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

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

Applicability to movement of irradiated fuel excludes movement of irradiated fuel within a properly sealed spent fuel shipping cask. The DC electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4.

ACTIONS

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

If two trains are required by LCO 3.8.10, the remaining train with DC power available may be capable of supporting sufficient systems to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features inoperable with the associated DC power

(continued)

BASE

ACTIONS

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

source(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCO ACTIONS. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions) that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or 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 required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

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

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

(continued)

BASE (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.6. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND	This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC power source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources - Operating," and LCO 3.8.5, "DC Sources - Shutdown."
APPLICABLE SAFETY ANALYSES	The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining at least one train of DC sources OPERABLE during accident conditions, in the event of: a. An assumed loss of all offsite AC power or all onsite AC power; or b. An assumed loss of offsite power and a worst case single active failure. Battery cell parameters satisfy the Criterion 3 of the NRC Policy Statement.
LCO	Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Electrolyte limits are conservatively established,

(continued)

BASES

LCO (continued)	allowing continued DC electrical system function even with Category A and B limits not met.
APPLICABILITY	The battery cell parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, battery electrolyte is only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

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

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

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

Verification that the Category C limits are met (Required Action A.2) provides assurance that during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is

(continued)

ACTIONS

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

considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A or B limits. This periodic verification is consistent with the normal Frequency of pilot cell Surveillances.

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

B.1

With one or more batteries with one or more battery cell parameters outside the Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as not completing the Required Actions of Condition A within the required Completion Time or average electrolyte temperature of representative cells falling below 67ºF are also cause for immediately declaring the associated DC electrical power subsystem inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 3), which recommends regular battery inspections (at least one per month) including voltage (measured to the nearest 0.01 Volts), specific gravity, and electrolyte temperature of pilot cells. In addition, if water is added to any pilot cell, the amount must be recorded. Data attained must be compared to the data from the previous SR to detect signs of abuse or deterioration. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.2

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program. In addition, within 24 hours of a battery discharge < 110 V or a battery overcharge > 150 V, the battery must be demonstrated to meet Category B limits. Transients, which may momentarily cause battery voltage to drop to ≤ 110 V, do not constitute a battery discharge provided the battery terminal voltage and float current return to pre-transient values. This inspection is also consistent with IEEE-450 (Ref. 3), which recommends special inspections following a severe discharge or overcharge, to ensure that no significant degradation of the battery occurs as a consequence of such discharge or overcharge. If water is added to any battery cell, the amount must be recorded. Data obtained must be compared to the data from the previous SR to detect signs of abuse or deterioration.

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells is ≥ 67ºF is consistent with a recommendation of IEEE-450 (Ref. 3), that states that the temperature of electrolytes in representative cells should be determined on a quarterly basis. Data obtained must be compared to the data from the previous SR to detect signs of abuse or deterioration.

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

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

Table 3.8.6-1

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

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

as pilot cells are those whose temperature, voltage, and electrolyte specific gravity approximate the state of charge of the entire battery.

The Category A limits specified for electrolyte level are based on manufacturer recommendations and are consistent with the guidance in IEEE-450 (Ref. 3), with the extra 3 inch allowance above the high water level indication for operating margin to account for temperatures and charge effects. In addition to this allowance, footnote a to Table 3.8.6-1 permits the electrolyte level to be above the specified maximum level during equalizing charge, provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 3) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on the recommendations of IEEE-450 (Ref. 3), which states that prolonged operation of cells < 2.13 V can reduce the life expectancy of cells.

The Category A limit specified for specific gravity for each pilot cell is ≥ 1.200 (0.015 below the manufacturer fully charged nominal specific gravity or a battery charging current that had stabilized at a low value). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 3), the specific gravity readings are based on a temperature of 77ºF (25ºC).

The specific gravity readings are corrected for actual electrolyte temperature and level. For each 3ºF (1.67ºC) above 77ºF (25ºC), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3ºF below 77ºF. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is ≥ 1.195 (0.020 below the manufacturer fully charged, nominal specific gravity) with the average of all connected cells > 1.205 (0.010 below the manufacturer fully charged, nominal specific gravity). These values are based on manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell will not mask overall degradation of the battery.

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

The Category C limits specified for electrolyte level (above the top of the plates and not overflowing) ensure that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C limits for float voltage is based on IEEE-450 (Ref. 3), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit of average specific gravity ≥ 1.195 is based on manufacturer recommendations (0.020 below the manufacturer recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery. The footnotes to Table 3.8.6-1 are applicable to Category A, B, and C specific gravity. Footnote (b) to Table 3.8.6-1 requires the above mentioned correction for electrolyte level and temperature, with the exception that

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

level correction is not required when battery charging current is < 2 amps on float charge. This current provides, in general, an indication of overall battery condition.

Because of specific gravity gradients that are produced during the recharging process, delays of several days may occur while waiting for the specific gravity to stabilize. A stabilized charger current is an acceptable alternative to specific gravity measurement for determining the state of charge. This phenomenon is discussed in IEEE-450 (Ref. 3). Footnote (c) to Table 3.8.6-1 allows the float charge current to be used as an alternate to specific gravity for up to 7 days following a battery recharge. Within 7 days, each connected cell's specific gravity must be measured to confirm the state of charge. Following a minor battery recharge (such as equalizing charge that does not follow a deep discharge) specific gravity gradients are not significant, and confirming measurements may be made in less than 7 days.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 15.
3. IEEE-450-1995.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 AC Instrument Bus Sources - Operating

BASES

BACKGROUND

The 120 V AC instrument supply is split into 8 buses. Instrument buses 2 and 3 are fed through an inverter from the "A" battery distribution system and the "B" battery distribution system, respectively. Instrument buses 1 and 4 are normally fed from 480 volt MCC-5 and MCC-6 respectively via their constant voltage transformers (CVT). An alternate power supply for instrument buses 1, 2, 3 and 4 is a common motor control center. Instrument buses 6, 7 (panels 7A and 7B), 8, and 9 (panels 9A and 9B) are powered from instrument buses 1, 2, 3, and 4 respectively, via breakers.

The 120 V AC instrument buses supply power to instrumentation and controls used to monitor and actuate the Reactor Protection System (RPS) and Engineered Safety Features (ESF) and other components. The inverters are the preferred source of power for Instrument buses 2, 3, 7 and 8 while the CVTs are the preferred source of power for Instrument buses 1, 4, 6 and 9.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The AC Instrument Bus Sources are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to portions of the RPS and ESFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC Instrument Bus Sources is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

unit. This includes maintaining required AC instrument buses OPERABLE during accident conditions in the event of:

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

b. An assumed loss of offsite power and a worst case single active failure.

AC Instrument Bus Sources are a part of the distribution system and, as such, satisfy Criterion 3 of the NRC Policy Statement.

LCO

The AC Instrument Bus Sources ensure the availability of AC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required AC Instrument Bus Sources OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The two inverters (one per train) ensure an uninterruptible supply of AC electrical power to four of the eight AC instrument buses even if the 480 V safety buses are de-energized.

Operable Instrument Bus Sources require the associated instrument bus to be powered by the inverter with output voltage and frequency within tolerances, and power input to the Instrument Bus Sources from the preferred source.

APPLICABILITY

The Instrument Bus Sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

(continued)

BASES

APPLICABILITY (continued)

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

Instrument Bus Sources requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, "AC Instrument Bus Sources - Shutdown."

ACTIONS

A.1

With a required AC Instrument Bus Sources inoperable, its associated AC instrument bus becomes inoperable until it is manually re-energized from its alternate AC source.

For this reason a Note has been included in Condition A requiring the entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating." This ensures that the instrument bus is re-energized within 2 hours.

Required Action A.1 allows 24 hours to fix the inoperable AC Instrument Bus Source and return it to service. The 24 hour limit is based upon engineering judgment, taking into consideration the time required to repair an AC Instrument Bus Source and the additional risk to which the unit is exposed because of the AC Instrument Bus Source inoperability. This has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems such a shutdown might entail. When the AC instrument bus is powered from its alternate AC source, it is relying upon interruptible AC electrical power sources (offsite). The AC Instrument Bus Source to the AC instrument buses is the preferred source for powering instrumentation trip setpoint devices.

B.1 and B.2

If the inoperable devices or components cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and associated AC instrument buses energized from the Inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation of the RPS and ESFAS connected to the AC instrument buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.8.7.2

This surveillance verifies that the required circuit breakers are closed and the associated instrument buses energized from the CVTs. Actual measurement of voltage is not required. Confirmation that the buses are energized by observing status lights, instrument displays, etc., is sufficient to confirm the instrument buses are energized. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.

3. UFSAR, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 AC Instrument Bus Sources - Shutdown

BASES

BACKGROUND

A description of the AC Instrument Bus Sources is provided in the Bases for LCO 3.8.7, "AC Instrument Bus Sources - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The AC Instrument Bus Sources are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protective System and Engineered Safety Features Actuation System instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC Instrument Bus Sources is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC Instrument Bus Sources to each AC instrument bus during MODES 5 and 6 ensures that:

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

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

c. Adequate power is available to mitigate events postulated during shutdown, such as a fuel handling accident.

The AC Instrument Bus Sources were previously identified as part of the distribution system and, as such, satisfy Criterion 3 of the NRC Policy Statement.

(continued)

BASES

LCO

The AC Instrument Bus Sources ensure the availability of electrical power for the instrumentation for systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. At least one AC instrument bus train energized by one battery powered inverter or a constant voltage transformer (CVT) ensure that the preferred source of AC instrument bus electrical power is available to at least one AC instrument bus. OPERABILITY of the inverters and CVTs requires that the AC instrument bus be powered by the associated inverter or CVT, as applicable. When the redundant train of the AC instrument bus electrical power distribution subsystem is required by LCO 3.8.10, the power source for this AC instrument bus may consist of:

1) the inverter powered by its associated battery;

2) the CVT; or

3) an offsite circuit providing power through a motor control center.

This ensures the availability of sufficient AC Instrument Bus Sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The AC Instrument Bus Sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

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

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

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

(continued)

BASES

APPLICABILITY (continued)

Applicability to movement of irradiated fuel excludes movement of irradiated fuel within a properly sealed spent fuel shipping cask. AC Instrument Bus Sources requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

ACTIONS

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

With one or more required AC instrument bus sources inoperable when two trains are required by LCO 3.8.10, "Distribution Systems - Shutdown," the remaining OPERABLE AC Instrument Bus Sources may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for positive reactivity additions. By the allowance of the option to declare required features inoperable with the associated AC Instrument Bus Source inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCOs' Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions) that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or 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 required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

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

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(continued)

BASES

ACTIONS

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

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC Instrument Bus Sources should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power or powered from a non-preferred source.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and required AC instrument buses energized from the inverter and that required circuit breakers are closed and required instrument buses are energized from the CVTs or other sources, as allowed by LCO 3.8.8.b. The verification of proper voltage and frequency output for the inverters ensures that the required power is readily available for the instrumentation connected to the associated AC instrument buses. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note which states that voltage and frequency measurement is not required for the AC instrument buses supplied from CVTs. For these buses, observing status lights, instrument displays, etc. is sufficient to confirm that the required power is readily available to the AC instrument buses supplied from CVTs

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 15.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems - Operating

BASES

BACKGROUND

The onsite AC, DC, and AC instrument bus electrical power distribution systems are divided by train into two redundant AC, DC, and AC instrument bus electrical power distribution subsystems.

The AC electrical power subsystem for each train consists of a primary Engineered Safety Feature (ESF) 480 V bus and secondary buses, distribution panels and motor control centers. Each 480 V ESF bus has at least one separate and independent offsite source of power as well as a dedicated onsite diesel generator (DG) source. Each 480 V ESF bus is normally connected to a preferred offsite source. The 480 V ESF bus E1 is normally powered from the 115 kV switchyard through the 115 kV startup transformer and station service transformer 2F. The 480 V ESF bus E2 is normally powered from the 230 kV switchyard through the 230 kV startup transformer and station service transformer 2G. After a loss of the preferred offsite power source to either 480 V ESF bus, a manual transfer of ESF bus E1 to the unit auxiliary transformer is performed to maintain a redundancy of power sources. Upon a loss of the 230 kV startup transformer, ESF bus E2 is transferred to the 115 kV startup transformer via 4.16 kV bus 3. If neither startup transformer is available, the unit auxiliary transformer can supply power to the entire onsite distribution system by backfeeding the main transformer from the 230 kV switchyard. Prior to backfeeding the main transformer from the 230 kV switchyard, the generator must be disconnected from the main transformer by removing the connecting straps. The main transformer backfeeding will only be performed during cold shutdown unless nuclear safety considerations require the configuration during hot shutdown when no other offsite power sources are available. If all offsite sources are unavailable, the onsite emergency DG supplies power to the 480 V ESF buses. Control power for the 4.16 kV buses 1, 2, 3 and 4 and 480 V breakers is supplied from the station batteries ‘A’ and ‘B’. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources - Operating," and the Bases for LCO 3.8.4, "DC Sources - Operating."

(continued)

BASES

BACKGROUND (continued)

The secondary AC electrical power distribution system for each train includes the safety related motor control centers, and distribution panels shown in Table B 3.8.9-1. The Auxiliary Feedwater (AFW) Header Discharge Valve to S/G "A", V2-16A and the Service Water System (SWS) Turbine Building Supply Valve (emergency supply), V6-16C are powered from both Train A and Train B of the AC electrical bus distribution system by utilization of Automatic Bus Transfer (ABT) devices and molded case circuit breakers connected to each AC distribution train. Magnetic trip elements for these circuit breakers (two breakers per valve) provide circuit protection to prevent common mode failure (i.e., transfer of a fault from one electrical bus to the redundant bus) of both trains of the AC distribution systems.

The 120 VAC instrument buses are arranged in two load groups per train. One load group is made up of two instrument buses normally powered from an inverter. The remaining load group is made up of two instrument buses powered from a constant voltage transformer powered from the associated AC emergency bus. The alternate power supply for the inverter supplied instrument buses and the constant voltage transformer supplied instrument buses is an AC source powered from the station AC power distribution system, and its use is governed by LCO 3.8.7, "AC Instrument Bus Sources - Operating."

There are two redundant 125 VDC electrical power distribution subsystems (one for each train).

The list of all required distribution buses is presented in Table B 3.8.9-1.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the UFSAR, Chapter 6 (Ref. 1), and in the FSAR, Chapter 15 (Ref. 2), assume ESF systems are OPERABLE. The AC, DC, and AC instrument bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

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

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

b. An assumed loss of offsite power and worst case single active failure.

The magnetic and thermal trip elements of the molded case circuit breakers for the Auxiliary Feedwater (AFW) Header Discharge Valve to S/G "A", V2-16A and the Service Water System (SWS) Turbine Building Supply Valve (emergency supply), V16-16C are required to function to prevent transferring a fault from one train of the AC distribution System to the other train of the AC distribution System (Ref. 3). For this to occur, a trip element for both of the breakers associated with one valve (one connected to each train of the AC Distribution System) would have to fail.

The distribution systems satisfy Criterion 3 of the NRC Policy Statement.

LCO

The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC instrument bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The AC, DC, and AC instrument bus electrical power distribution subsystems are required to be OPERABLE.

Maintaining the Train A and Train B AC, DC, and AC instrument bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or within the electrical power

(continued)

BASES

LCO (continued)

distribution subsystems will not prevent safe shutdown of the reactor. OPERABLE AC electrical power distribution subsystems require the associated buses, motor control centers, distribution panels and auxiliary fuse panels to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE instrument bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated inverter via inverted DC voltage, the constant voltage transformer or the alternate feed.

Based on the number of safety significant electrical loads associated with each bus listed in Table B 3.8.9-1, if one or more of the buses becomes inoperable, entry into the appropriate Conditions and Required Actions of LCO 3.8.9 is required. Other buses, such as motor control centers (MCC) and distribution panels, which help comprise the AC and DC distribution systems are not listed in Table B 3.8.9-1. The loss of electrical loads associated with these buses may not result in a complete loss of a redundant safety function necessary to shut down the reactor and maintain it in a safe condition. Therefore, should one or more of these buses become inoperable due to a failure not affecting the OPERABILITY of a bus listed in Table B 3.8.9-1 (e.g., a breaker supplying a single MCC fails open), the individual loads on the bus would be considered inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. However, if one or more of these buses is inoperable due to a failure also affecting the OPERABILITY of a bus listed in Table B 3.8.9-1 (e.g., loss of a 480 V emergency bus, which results in de-energization of all buses powered from the 480 V emergency bus), then although the individual loads are still considered inoperable, the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 480 V emergency bus).

The magnetic and thermal trip elements of at least one of the molded case circuit breakers for both the Auxiliary

(continued)

BASES

LCO (continued)

Feedwater (AFW) Header Discharge Valve to S/G "A", V2-16A and the Service Water System (SWS) Turbine Building Supply Valve (emergency supply), V16-16C are required to be OPERABLE to provide isolation between the separate AC distribution subsystems.

In addition, tie breakers between redundant safety related AC, DC, and AC instrument bus power distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, that could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the affected redundant electrical power distribution subsystems are considered inoperable. This applies to the onsite, safety related redundant electrical power distribution subsystems. It does not, however, preclude redundant 480 V Emergency buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

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

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

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems - Shutdown."

ACTIONS

A.1

With one or more required AC buses, motor control centers, or distribution panels, except AC instrument buses, in one train inoperable, the remaining AC electrical power distribution subsystem in the other train is capable of

(continued)

BASES

ACTIONS

A.1 (continued)

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

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

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 2 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

(continued)

BASES

ACTIONS

A.1 (continued)

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

B.1

With one AC instrument bus subsystem inoperable, the remaining OPERABLE AC instrument buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC instrument bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated alternate AC supply.

Condition B represents one AC instrument bus without power; potentially both the DC source or the constant voltage transformer and the associated alternate AC source are nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of all noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining instrument buses and restoring power to the affected instrument bus.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate instrument AC power. Taking exception to LCO 3.0.2 for components without adequate instrument AC power, that would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

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

(continued)

BASES

ACTIONS

B.1 (continued)

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate instrument AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

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

The 2 hour Completion Time takes into account the importance to safety of restoring the AC instrument bus to OPERABLE status, the redundant capability afforded by the other OPERABLE instrument buses, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the instrument bus distribution system. At this time, an AC train could again become inoperable, and instrument bus distribution restored OPERABLE. This could continue indefinitely.

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

C.1

With DC bus(es) in one train inoperable, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall

(continued)

ACTIONS

C.1 (continued)

reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

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

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

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

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

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

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 4). The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have

(continued)

BASES

ACTIONS

C.1 (continued)

been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution restored OPERABLE. This could continue indefinitely.

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

D.1 and E.1

With trip elements of both molded case circuit breakers associated with either the Aux. Feedwater Header Discharge Valve to S/G "A", V2-16A or the Service Water Turbine Building Supply Valve (emergency supply), V16-16C inoperable, the potential exist that a single failure could adversely affect both trains of the AC Distribution System. For this to occur, a trip element for both of the breakers associated with one valve (one connected to each train of the AC Distribution System) would have to fail. Therefore, one of the associated molded case circuit breaker(s) for each affected valve must be placed in the open position.

Engineering judgment and operating experience indicates that two hours is adequate time to open the affected circuit breaker(s). The two hour Completion Time take into account the importance to safety of opening the affected circuit breakers, the low probability of inoperability of a trip element for both circuit breakers concurrent with a fault on the associated circuit and the low probability of a DBA occurring during this period.

With the affected circuit breaker(s) open, normal or alternate AC power is not available to the associated valve. This Note ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by the removal of the power source(s) from the associated valve.

(continued)

BASES

ACTIONS (continued)

F.1 and F.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 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.

G.1

With two trains with inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other instrument functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required AC, DC, and AC instrument bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by a Note which states that Voltage measurement is not required for the AC Instrument buses supplied from Constant Voltage Transformers (CVTs). For these buses confirmation that the buses are energized by observing status lights, instrument displays, etc., is sufficient to confirm the buses are energized.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.9.2 and SR 3.8.9.3

The two breakers associated with each ABT will trip on over current as required to prevent fault from affecting both trains of the AC Distribution System. The Surveillance Frequencies are controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 15.

3. SER for HBRSEP Unit No. 2 Amendment 123, dated Sept. 5, 1989

4. Regulatory Guide 1.93, December 1974.

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	TRAIN A*	TRAIN B*
AC buses	4160 V 480 V	4.16 kV Bus 6 480 V Bus E1	4.16 kV Bus 9 480 V Bus E2
DC buses	125 V	MCC A Distribution Panel A	MCC B Distribution Panel B
AC instrument buses (IB)	120V	IB 1 IB 2 IB 6 IB 7 (A & B)	IB 3 IB 4 IB 8 IB 9 (A & B)

* Each train of the AC and DC electrical power distribution systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems - Shutdown

BASES

BACKGROUND

A description of the AC, DC, and AC instrument bus electrical power distribution systems is provided in the Bases for LCO 3.8.9, "Distribution Systems - Operating."

APPLICABLE SAFETY ANALYSES

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

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

The OPERABILITY of the minimum AC, DC, and AC instrument bus electrical power distribution subsystems during MODES 5 and 6, and during movement of irradiated fuel assemblies ensures that:

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

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

c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

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

(continued)

BASES (continued)

LCO

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

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

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

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

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

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

Applicability to movement of irradiated fuel excludes movement of irradiated fuel within a properly sealed spent fuel shipping cask. The AC, DC, and AC instrument bus electrical power distribution subsystems requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9.

(continued)

BASES (continued)

ACTIONS

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

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions that could result in loss of required SDM (MODE 5) or boron concentration (MODE 6)). Suspending positive reactivity additions that could result in failure to meet the minimum SDM or 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 required in the RCS for minimum SDM or refueling boron concentration. This may result in an overall reduction in RCS boron concentration, but provides acceptable margin to maintaining subcritical operation. Introduction of temperature changes including temperature increases when operating with a positive MTC must also be evaluated to ensure they do not result in a loss of required SDM.

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

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal (RHR) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR ACTIONS would not be entered.

(continued)

BASES

ACTIONS

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

Therefore, Required Action A.2.5 is provided to direct declaring RHR inoperable, which results in taking the appropriate RHR actions.

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

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the AC, DC, and AC instrument bus electrical power distribution subsystems are functioning properly, with all the buses energized. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

This SR is modified by Note which states that voltage measurement is not required for the AC Instrument buses supplied from Constant Voltage Transformers (CVTs). For these buses confirmation that the buses are energized by observing status lights, instrument displays, etc., is sufficient to confirm the buses are energized.

REFERENCES

1. UFSAR, Chapter 6.

2. UFSAR, Chapter 15.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentrations of the Reactor Coolant System (RCS), the refueling canal, and the refueling cavity during refueling ensures that the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration limit is specified in the Core Operating Limits Report (COLR). Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of $k_{eff} \leq 0.9433$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures.

HBRSEP design criteria requires that two independent reactivity control systems of different design principles be provided (Ref. 1). One of these systems must be capable of holding the reactor core subcritical under cold conditions. The Chemical and Volume Control System (CVCS) is the system capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration.

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized and the vessel head is unbolted, the head is slowly removed to form the refueling cavity. The refueling canal and the refueling cavity are then flooded with borated water from the refueling water storage tank through the open reactor vessel by the use of the Safety Injection (SI) System or Residual Heat Removal (RHR) System pumps.

The pumping action of the SI or RHR System in the RCS and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added concentrated boric acid with the water in the refueling

(continued)

BASES

BACKGROUND (continued)	canal. The RHR System is in operation during refueling (see LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level") to provide forced circulation in the RCS and assist in maintaining the boron concentrations in the RCS, the refueling canal, and the refueling cavity above the COLR limit.
APPLICABLE SAFETY ANALYSES	During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident in the accident analysis and is conservative for MODE 6. The boron concentration limit specified in the COLR is based on the core reactivity at the beginning of each fuel cycle (the end of refueling) and includes an uncertainty allowance. The required boron concentration and the plant refueling procedures that verify the correct fuel loading plan (including full core mapping) ensure that the k_{eff} of the core will remain ≤ 0.9433 during the refueling operation. Hence, at least a 6% Δk/k margin of safety is established during refueling. During refueling, the water volume in the spent fuel pool, the transfer canal, the refueling canal, the refueling cavity, and the reactor vessel form a single mass. As a result, the soluble boron concentration is relatively the same in each of these volumes. The limiting boron dilution accident analyzed occurs in MODE 5 (Ref. 2). A detailed discussion of this event is provided in Bases B 3.1.1, "SHUTDOWN MARGIN (SDM)." The RCS boron concentration satisfies Criterion 2 of the NRC Policy Statement.
LCO	The LCO requires that a minimum boron concentration be maintained in the RCS, the refueling canal, and the refueling cavity while in MODE 6. The boron concentration limit specified in the COLR ensures that a core k_{eff} of

(continued)

BASES

LCO (continued)

≤ 0.9433 is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.

APPLICABILITY

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a k_{eff} ≤ 0.9433. Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," ensure that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical.

ACTIONS

A.1 and A.2

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of any coolant volume in the RCS, the refueling canal, or the refueling cavity is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately.

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position. Operations that individually add limited positive reactivity (e.g., temperature fluctuations, inventory addition, or temperature control fluctuations), but when combined with all other operations affecting core reactivity (e.g., intentional boration) result in overall net negative reactivity addition, are not precluded by this action.

A.3

In addition to immediately suspending CORE ALTERATIONS and positive reactivity additions, boration to restore the concentration must be initiated immediately.

In determining the required combination of boration flow rate and concentration, no unique Design Basis Event must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron concentration as soon as possible,

(continued)

BASES

ACTIONS

A.3 (continued)

the operator should begin boration with the best source available for unit conditions.

Once actions have been initiated, they must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR ensures that the coolant boron concentration in the RCS, the refueling canal, and the refueling cavity is within the COLR limits. The boron concentration of the coolant in each volume is determined periodically by chemical analysis.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 3.1.

2. UFSAR, Chapter 15.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Nuclear Instrumentation

BASES

BACKGROUND	The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. The installed source range neutron flux monitors are part of the Nuclear Instrumentation System (NIS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core. The installed source range neutron flux monitors are BF3 detectors operating in the proportional region of the gas filled detector characteristic curve. The detectors monitor the neutron flux in counts per second. The instrument range covers six decades of neutron flux (1E+6 cps) with a 5% instrument accuracy. The detectors also provide continuous visual indication in the control room and an audible alarm to alert operators to a possible dilution accident. The NIS is designed in accordance with the criteria presented in the UFSAR Section 3.1 (Ref. 1).
APPLICABLE SAFETY ANALYSES	Two OPERABLE source range neutron flux monitors are required to provide a signal to alert the operator to unexpected changes in core reactivity such as with a boron dilution accident (Ref. 2) or an improperly loaded fuel assembly. The source range neutron flux monitors satisfy Criterion 3 of the NRC Policy Statement.
LCO	This LCO requires that two source range neutron flux monitors be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. For the purposes of this LCO, OPERABILITY of the source range flux monitors includes both channels with continuous visual count rate indication in the control room. Additionally, during periods of core alteration, one channel shall have an audible count rate indication available in the containment.

(continued)

BASES (continued)

APPLICABILITY

In MODE 6, the source range neutron flux monitors must be OPERABLE to determine changes in core reactivity. There are no other direct means available to check core reactivity levels. In MODES 2, 3, 4, and 5, these same installed source range detectors and circuitry are also required to be OPERABLE by LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation."

ACTIONS

A.1 and A.2

With only one required source range neutron flux monitor OPERABLE, an OPERABLE Post Accident Monitor (PAM) source range neutron monitor may be used to provide the required redundancy. Required Action A.1 ensures that the PAM source range neutron monitor is indicating in the control room. Since the PAM source range neutron monitor provides only visual indication of count rate in the Control Room and has no audible count rate capability, Required Action A.2 requires that the indicated count rate from the PAM source range neutron monitor be logged within 30 minutes and once per 30 minutes thereafter. The Completion Times are reasonable considering that there remains one OPERABLE source range monitor with audible count rate and alarm function, and recognition of the time required to complete manual operator actions in response to the boron dilution event.

B.1 and B.2

If the Required Actions and Completion Times of Condition A are not met, redundant means of monitoring core reactivity conditions are not assured. CORE ALTERATIONS and introduction of coolant into the RCS with boron concentration less than required to meet the minimum boron concentration of LCO 3.9.1 must be suspended immediately. 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 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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

operation. Performance of Required Action B.1 shall not preclude completion of movement of a component to a safe position.

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

With no source range neutron flux monitor OPERABLE, action to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, action shall be continued until a source range neutron flux monitor is restored to OPERABLE status. Since the source range neutron monitors are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and positive reactivity additions must be suspended immediately. Performance of Required Action C.2 shall not preclude completion of a component to a safe condition.

C.4

With no source range neutron flux monitor OPERABLE, there are no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are not to be made, the core reactivity condition is stabilized until the source range neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

The Completion Time of 4 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration. The Frequency of once per 12 hours ensures that unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this time period.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

SR 3.9.2.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.2.2

SR 3.9.2.2 is the performance of a CHANNEL CALIBRATION. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the source range neutron flux monitors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. The CHANNEL CALIBRATION for the PAM source range neutron flux monitors only applies to the portion of the channel applicable to providing visual indication of neutron count rate in the Control Room. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 3.1.
2. UFSAR, Section 15.4.6.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Containment Penetrations

BASES

BACKGROUND

During movement of recently irradiated fuel assemblies within containment, a release of fission product radioactivity within containment will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, this is accomplished by maintaining containment OPERABLE as described in LCO 3.6.1, "Containment." In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are closed or capable of being closed. Since there is no potential for containment pressurization, the Appendix J leakage criteria and tests are not required.

The containment serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation doses are maintained within the limits of 10 CFR 50.67. Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. During movement of recently irradiated fuel assemblies within containment, the equipment hatch must be held in place by at least four bolts. Good engineering practice dictates that the bolts required by this LCO be approximately equally spaced.

The containment air lock, which is also part of the containment pressure boundary, provides a means for personnel access during MODES 1, 2, 3, and 4 unit operation in accordance with LCO 3.6.2, "Containment Air Lock." The air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown

(continued)

BASES

BACKGROUND (continued)

when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of the air lock to remain open for extended periods when frequent containment entry is necessary. During movement of recently irradiated fuel assemblies within containment, containment closure is required; therefore, the door interlock mechanism may remain disabled, but one air lock door must always remain closed.

The requirements for containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted from escaping to the environment. The closure restrictions are sufficient to restrict fission product radioactivity release from containment due to a fuel handling accident involving handling recently irradiated fuel during refueling.

The Containment Ventilation System includes the Containment Purge System and the Containment Pressure and Vacuum Relief System. The Containment Purge System has a 42 inch supply penetration and a 42 inch exhaust penetration. The Containment Pressure and Vacuum Relief System has two separate 6 inch penetrations. The two valves in each of the penetrations can be opened intermittently, but are closed automatically by the Containment Isolation System. Neither of the subsystems is subject to a Specification in MODE 5.

In MODE 6, large air exchanges are necessary to conduct refueling operations. The normal 42 inch purge system is used for this purpose, and all four isolation valves are automatically closed in accordance with LCO 3.3.6, "Containment Ventilation Isolation Instrumentation." The Containment Pressure and Vacuum Relief System remains operational in MODE 6, and all four isolation valves are also automatically closed by the Containment Ventilation Isolation System.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods must be approved and may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations during fuel movements.

(continued)

BASES (continued)

APPLICABLE SAFETY ANALYSES

During movement of irradiated fuel assemblies within containment, the most severe radiological consequences result from a fuel handling accident involving handling recently irradiated fuel. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 1). Fuel handling accidents analyzed include dropping a single irradiated fuel assembly and handling tool or a heavy object onto other irradiated fuel assemblies. The requirements of LCO 3.9.6, "Refueling Cavity Water Level," and irradiated fuel movement with containment closure capability or a minimum decay time of 116 hours without containment closure capability ensure that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within (≤ 25%)the dose limits specified in 10 CFR 50.67.

Containment penetrations satisfy Criterion 3 of the NRC Policy Statement.

LCO

This LCO limits the consequences of a fuel handling accident involving handling recently irradiated fuel in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment ventilation penetrations. For the OPERABLE containment ventilation penetrations, this LCO ensures that these penetrations are isolable by the Containment Ventilation Isolation System. The OPERABILITY requirements for this LCO ensure that the automatic containment ventilation valve closure times specified in the UFSAR can be achieved and, therefore, meet the assumptions used in the safety analysis to ensure that releases through the valves are terminated, such that radiological doses are within the acceptance limit.

APPLICABILITY

The containment penetration requirements are applicable during movement of recently irradiated fuel assemblies within containment because this is when there is a potential

(continued)

BASES (continued)

APPLICABILITY (continued)

for the limitting fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1. In MODES 5 and 6, when movement of irradiated fuel assemblies within containment is not being conducted, the potential for a fuel handling accident does not exist. Additionally, due to radioactive decay, a fuel handling accident involving handling fuel that was not recently irradiated (i.e., fuel that has not occupied part of a critical reactor core within the previous 116 hours) will result in doses that are well within the guideline values specified in 10 CFR 50.67 even without containment closure capability. Therefore, under these conditions no requirements are placed on containment penetration status.

ACTIONS

A.1

If the containment equipment hatch, air lock, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, including the Containment Ventilation Isolation System not capable of automatic actuation when the containment ventilation valves are open, the unit must be placed in a condition where the isolation function is not needed. This is accomplished by immediately suspending movement of recently irradiated fuel assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

This Surveillance demonstrates that each of the containment penetrations required to be in its closed position is in that position. The Surveillance on the open ventilation valves will demonstrate that the valves are not blocked from closing. Also the Surveillance will demonstrate that each valve operator has motive power, which will ensure that each valve is capable of being closed by an OPERABLE automatic containment ventilation isolation signal.

This Surveillance ensures that a postulated fuel handling

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1 (continued)

Accident involving handling recently irradiated fuel that releases fission product radioactivity within the containment will not result in a significant release of fission product radioactivity to the environment. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.3.2

This Surveillance demonstrates that each containment ventilation valve actuates to its isolation position on manual initiation or on an actual or simulated high radiation signal. SR 3.6.3.5 demonstrates that the isolation time of each valve is in accordance with the Inservice Testing Program requirements. These Surveillances performed during MODE 6 will ensure that the valves are capable of closing after a postulated fuel handling accident involving handling recently irradiated fuel to limit a release of fission product radioactivity from the containment. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 15.7.4.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Residual Heat Removal (RHR) and Coolant Circulation - High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS) to provide mixing of borated coolant and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchanger(s), where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown or decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and the bypass. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200ºF, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. One train of the RHR System is required to be operational in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to prevent this challenge. The LCO does permit de-energizing the RHR pump for short durations, under the condition that the boron concentration is not diluted. This conditional de-energizing of the RHR pump does not result in a challenge to the fission product barrier.

Although the RHR System does not meet a specific criterion of the NRC Policy Statement, it was identified in the NRC Policy Statement as an important contributor to risk

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

reduction. Therefore, the RHR System is retained as a Specification.

LCO

Only one RHR train is required for decay heat removal in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange. Only one RHR train is required to be OPERABLE, because the volume of water above the reactor vessel flange provides backup decay heat removal capability. At least one RHR train must be OPERABLE and in operation to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR train includes an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. The flow path starts in one of the RCS hot legs and is returned to the RCS cold legs.

The LCO is modified by a Note that allows the required operating RHR train to be removed from service for up to 1 hour in any 8 hour period, provided no operations are permitted that would dilute the RCS boron concentration with coolant at boron concentrations less than required to meet the minimum boron concentration of LCO 3.9.1. Boron concentration reduction, with coolant at boron concentrations less than required to assure the minimum required RCS boron concentration is maintained, is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles and RCS to RHR isolation valve testing. During this 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling cavity.

(continued)

BASES (continued)

APPLICABILITY

One RHR train must be OPERABLE and in operation in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to provide decay heat removal. The 23 ft water level was selected because it corresponds to the 23 ft requirement established for fuel movement in LCO 3.9.6, "Refueling Cavity Water Level." Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). RHR train requirements in MODE 6 with the water level < 23 ft are located in LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level."

ACTIONS

RHR train requirements are met by having one RHR train OPERABLE and in operation, except as permitted in the Note to the LCO.

A.1

If RHR train requirements are not met, 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 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.

A.2

If RHR train requirements are not met, actions shall be taken immediately to suspend loading of irradiated fuel assemblies in the core. With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level of 23 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase decay heat load, such as loading a fuel assembly, is a prudent action under this condition.

(continued)

BASES

ACTIONS (continued)

A.3

If RHR train requirements are not met, actions shall be initiated and continued in order to satisfy RHR train requirements. With the unit in MODE 6 and the refueling water level ≥ 23 ft above the top of the reactor vessel flange, corrective actions shall be initiated immediately.

A.4

If RHR train requirements are not met, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR train requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance requires verification that one train 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 controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 5.4.4.

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) to provide mixing of borated coolant, and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchangers where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) and the bypass lines. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200ºF, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to the boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant will eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Two trains of the RHR System are required to be OPERABLE, and one train in operation, in order to prevent this challenge.

Although the RHR System does not meet a specific criterion of the NRC Policy Statement, it was identified in the NRC Policy Statement as an important contributor to risk reduction. Therefore, the RHR System is retained as a Specification.

LCO

In MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, both RHR trains must be OPERABLE.

(continued)

BASES

LCO (continued)

Additionally, one train of RHR must be in operation in order to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR train consists of an RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path. The normal flow path starts in one of the RCS hot legs and is returned to the RCS cold legs.

Both RHR pumps may be aligned to the Refueling water storage tank to support filling the refueling cavity or for performance of required testing.

APPLICABILITY

Two RHR trains are required to be OPERABLE, and one RHR train 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 train 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."

ACTIONS

A.1 and A.2

If less than the required number of RHR trains are OPERABLE, action shall be immediately initiated and continued until the RHR train 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 train is required to be OPERABLE and in operation. An immediate

(continued)

BASES

ACTIONS

A.1 and A.2 (Continued)

Completion Time is necessary for an operator to initiate corrective actions.

B.1

If no RHR train 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 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 train is in operation, actions shall be initiated immediately, and continued, to restore one RHR train to operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR trains and one operating RHR train should be accomplished expeditiously.

B.3

If no RHR train is in operation, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed within 4 hours. With the RHR train requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures that dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on operating experience to close all penetrations

.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This SR requires verification that one train 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 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 controlled under the Surveillance Frequency Control Program.

REFERENCES

1. UFSAR, Section 5.4.4.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Refueling Cavity Water Level

BASES

BACKGROUND

The movement of irradiated fuel assemblies within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange. During refueling, this maintains sufficient water level in the containment, refueling canal, fuel transfer canal, refueling cavity, and spent fuel pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Ref. 1). Sufficient iodine activity would be retained to limit offsite doses from the accident to within Regulatory Guide 1.183 and 10 CFR 50.67 limits (Refs. 2 and 3)

APPLICABLE SAFETY ANALYSES

During movement of irradiated fuel assemblies, the water level in the refueling canal and the refueling cavity is an initial condition design parameter in the analysis of a fuel handling accident in containment (Ref. 1). A minimum water level of 23 ft allows a decontamination factor of 200 to be used in the accident analysis for iodine. Therefore, consistent with Regulatory Guide 1.183, Appendix B.2, the overall effective iodine decontamination factor is 200 for the refueling cavity, with a resulting chemical species released from the water of 57% elemental and 43% organic iodine (Ref. 1).

The fuel handling accident analysis inside containment is described in Reference 1. With a minimum water level of 23 ft and a minimum decay time of 116 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses are maintained within allowable limits (Refs. 2 and 3).

Refueling cavity water level satisfies Criterion 2 of the NRC Policy Statement.

(continued)

BASES

LCO

A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits.

APPLICABILITY

LCO 3.9.6 is applicable when moving irradiated fuel assemblies within containment. The LCO minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pool are covered by LCO 3.7.12, "Fuel Storage Pool Water Level."

ACTIONS

A.1

With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving moving irradiated fuel assemblies within containment shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 1).

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS	SR 3.9.6.1 (continued) The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.
REFERENCES	1. UFSAR, Section 15.7.4. 2. 10 CFR 50.67. 3. Regulatory Guide 1.183.

B 3.9 REFUELING OPERATIONS

B 3.9.7 Containment Purge Filter System

BASES

BACKGROUND

The Containment Purge Filter System filters airborne radioactivity released to the containment following a fuel handling accident involving handling recently irradiated fuel in the containment. During refueling outages, the Containment Purge Filter System, in conjunction with other normally operating systems, also provides environmental control of temperature and humidity in the containment.

The Containment Purge Filter System is a single train system which consists of a prefilter, a high efficiency particulate air (HEPA) filter, an activated charcoal adsorber section for removal of gaseous activity (principally iodines), and two fans (only one of the fans is required, the second fan is a spare). Ductwork, valves or dampers, and instrumentation also form part of the system.

The Containment Purge Filter System is a manually intitiated system, which may also be operated during normal plant operations.

The Containment Purge Filter System is discussed in the UFSAR, Sections 6.5.1, 9.4.3, and 15.7.4 (Refs. 1, 2, and 3, respectively) because it may be used for normal, as well as post accident, atmospheric cleanup functions.

APPLICABLE SAFETY ANALYSES

The containment purge filter system is not used for mitigation of the fuel handling accident as described in UFSAR Section 15.7.4. This system is required to be OPERABLE and in operation during the movement of recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 116 hours). In the event of a fuel handling accident involving recently irradiated fuel, the containment purge filter system, in conjunction with the containment ventilation isolation requirements of LCO 3.3.6 and the containment closure requirements of LCO 3.9.3, would significantly impede the radioactive release.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	The Containment Purge Filter System satisfies Criterion 3 of the NRC Policy Statement.
LCO	The Containment Purge Filter System is required to be OPERABLE and operating. When the Containment Purge Filter System is in operatilon, the exhaust flow from containment shall discharge through the HEPA and impregnated charcoal filters. The Containment Purge Filter System is considered OPERABLE when: a. One fan is OPERABLE; b. HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration function; and c. Ductwork, valves, and dampers are OPERABLE, and air flow can be maintained.
APPLICABILITY	During movement of recently irradiated fuel in the containment, the Containment Purge Filter System is required to be OPERABLE and operating to alleviate the consequences of a fuel handling accident involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 116 hours).
ACTIONS	<u>A-1 and A-2</u> When the Containment Purge Filter System is inoperable or not in operation during movement of recently irradiated fuel assemblies in containment, Required Action A.1 requires each penetration providing direct access from the containment atmosphere to the outside atmosphere to be immediately

(continued)

BASES

ACTIONS

A.1and A.2 (continued)

closed. Closure may be achieved by a closed manual or automatic valve, blind flange, or equivalent method. Equivalent closure methods must be approved and may include use of a material that can provide a temporary atmospheric pressure, ventilation barrier for the penetration during fuel movements. Alternately, Required Action A.2 may be taken to place the unit in a condition in which the LCO does not apply. Required Action A.2 requires immediate suspension of movement of recently irradiated fuel assemblies in containment. Suspension of this activity does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.7.1

This SR verifies that the relative humidity of the containment atmosphere to be processed by the Containment Purge Filter System is ≤ 70%. This ensures that the testing performed to validate the safety analysis assumptions relative to charcoal filter efficiency, bounds actual plant conditions for relative humidity at the inlet of the Containment Purge Filter System charcoal filter. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.7.2

This SR verifies that the Containment Purge Filter System is in operation and maintaining containment pressure negative relative to the adjacent auxiliary building areas. This verification ensures that containment pressure is being maintained negative with respect to the outside atmosphere since the pressure of the auxiliary building areas is normally maintained negative with respect to the outside atmosphere. The Containment Purge Filter

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.7.2 (continued)

System is assumed to maintain a slight negative pressure in the containment, to prevent unfiltered leakage to the outside atmosphere. The Surveillance Frequency is controlled under the Surveillance Frequency Control Program.

SR 3.9.7.3

This SR verifies that the required Containment Purge Filter System filter testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

REFERENCES

1. UFSAR, Section 6.5.1.
2. UFSAR, Section 9.4.3.
3. UFSAR, Section 15.7.4.
4. 10 CFR 50.67.

Enclosure 5
Quality Assurance Program Description, Amendment 46

DUKE ENERGY CORPORATION

TOPICAL REPORT

Quality Assurance Program Description

Operating Fleet

DUKE-QAPD-001 -A-

QUALITY ASSURANCE

PROGRAM POLICY STATEMENT

Duke Energy Corporation (DEC) designs, procures, constructs and operates its nuclear plants in a manner that ensures the health and safety of the public and workers. These activities are performed in compliance with the requirements of the Code of Federal Regulations (CFR), the applicable Nuclear Regulatory Commission (NRC) Facility Operating Licenses, and applicable laws and regulations of the state and local governments.

The applicable Quality Assurance Program (QAP) is the Quality Assurance Program Description (QAPD) contained or referenced in each nuclear plant's Updated Final Safety Analysis Report and the associated implementing documents. Together they provide for control of DEC activities that affect the quality of safety-related nuclear plant structures, systems, and components (SSCs) and include all planned and systematic activities necessary to provide adequate confidence that such SSCs will perform satisfactorily in service. The QA Program may also be applied to certain equipment and activities that are not safety-related, but support safe plant operations, or where other NRC guidance establishes program requirements.

10 CFR 50.69, Risk-informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors, is a voluntary regulation that provides alternative approaches for establishing the requirements for treatment of a structure, system, or components using a risk informed method of categorization according to safety significance. Applicability and scope of SSCs will be in accordance with approved processes and detailed in site licensing documents. This regulation is applicable to Duke sites that have received NRC approval. At the time of this Amendment, Brunswick, Harris, and Robinson have received NRC approval, however, these exemptions apply to any site that has received NRC approval for 10 CFR 50.69 implementation. SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of the QAPD as they are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule.

As part of implementing 10 CFR 50.69, engineering will establish a collection of program elements to monitor and / or maintain SSC critical attributes ensuring reasonable confidence in the continued capability and reliability of the design basis functions. These elements include, inspection and testing, corrective actions, feedback and process adjustments, performance monitoring, program documentation, and reporting, as applicable to meet 10CFR 50.69(d), (e), (f), and (g). DEC implements the requirements of the QAPD commensurate with the safety classification of the SSCs, as described in applicable licensing and design documents, and implementing procedures.

The QAPD is the top-level policy document that establishes DEC’s overall philosophy regarding achievement and assurance of quality. Implementing documents assign detailed responsibilities and requirements and define the organizational interfaces involved in conducting activities within the scope of the QAP. Compliance with the QAP is mandatory for individuals involved directly or indirectly with its implementation.

DEC personnel have authority commensurate with their responsibility, including the authority to stop work that does not conform to established requirements. This stop work authority may be exercised in accordance with established nuclear system procedures.

Figure 17-1, Duke Energy Corporation Quality Assurance Policy Statement

Summary of Changes

Changes since last NRC update at Amendment 45

Except where noted, changes are denoted by change bars in the margins.

DRR #	Description of Change
02249848	This change is to revise the QAPD to reflect the relocation of Unit/Facility/Plant staff qualification (ANSI N18.1-1971) requirements from each facilities technical specifications to the QAPD.

CONTENTS

LIST OF FIGURES:

LIST OF TABLES

17 QUALITY ASSURANCE

17.1 QA DURING DESIGN AND CONSTRUCTION

NOTE: Not included, this description of the Quality Assurance Program follows Standard Review Plan Section 17.3 for format and content.

17.2 OPERATIONAL QA

NOTE: Not included, this description of the Quality Assurance Program follows Standard Review Plan Section 17.3 for format and content.

17.3 QUALITY ASSURANCE PROGRAM DESCRIPTION

INTRODUCTION

The Duke Energy Corporation Quality Assurance Program (QAP) Policy Statement in Figure 17-1 describes the corporate policy and assigns responsibility for implementation of the QAP.

Duke Energy Corporation maintains full responsibility for assuring its nuclear power plants are designed, constructed, tested and operated in conformance with good engineering practices, applicable regulatory requirements and specified design bases and in a manner to protect the public health and safety. To this end Duke Energy Corporation has established and implemented a Quality Assurance Program which conforms to the criteria established in Appendix B to Title 10 Code of Federal Regulations (10 CFR), Part 50, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants" published June 27, 1970 (35 F. R. 10499), amended September 17, 1971 (36 F. R. 18301), amended January 20, 1975 (40 F. R. 3210D), and amended August 28, 2007 (72 F. R. 49505).

This document follows the format and content guidance of NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants", Section 17.3, "Quality Assurance Program Description," except that the Duke Energy Corporation QAP is based on ANSI N18.7 and the ANSI N45.2 series standards in lieu of ANSI/ASME NQA-1 and NQA-2. This document is applicable to Duke Energy Corporation operating nuclear power stations as referenced by Chapter 17 of each station's UFSAR for those systems, components, items, and services that have been determined to be nuclear safety related – with the exception that SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document. These 50.69 LSS SSCs are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule.

This document is organized with a generic description of the organization and overview of the QAP in the main body of the document. Site specific details for the Quality Assurance Program Description along with conformance to the regulatory positions of the NRC QA Regulatory Guides are addressed in separate attachments as follows:

- Attachment A, Brunswick Specific QAPD
- Attachment B, Harris Specific QAPD
- Attachment C, Robinson Specific QAPD
- Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Each Attachment follows the section numbering in the main body of the document. The Brunswick, Harris, and Robinson attachments contain the conformance to the QA related

Regulatory Guides, identified in Table 17-1, transferred from Chapter 1 of each respective UFSAR. Each attachment also contains supplemental descriptions transferred from each respective UFSAR Chapter 17, Section 17.3 when detail was included beyond the generic text in the main body. Attachment D contains the conformance to the QA related Regulatory Guides, identified in Table 17-1, transferred from Amendment 40 of the Duke Energy Carolinas Topical Report Quality Assurance Program. Attachment D also contains supplemental descriptions from the Duke Energy Carolinas Topical Report Quality Assurance Program when detail was included beyond the generic text in the main body.

As discussed herein, the Quality Assurance Program (QAP) includes the description contained in this document and the controlled documents providing implementation of the requirements of this document, including the requirements of industry standards to the degree identified in Table 17-1, Conformance with QA Regulatory Guides and Industry Standards, and Table 17-2, Site Specific Response to Regulatory Guides and Industry Standards. The QAP provides a method of applying graded controls to certain non-safety related systems, components, items, and services (such as fire protection and radioactive waste structures, systems, and components) – with the exception that SSCs categorized as Low Safety Significant in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document as allowed by the rule.

Subsequent changes to the Duke Energy Corporation QAP are incorporated in this document as identified in Section 17.3.1.7. The QAP controlled implementing documents are used and updated as necessary to assure the nuclear generating units are managed such that they will be operated and maintained in a safe manner.

DEFINITIONS

The following definitions are applicable to terms used in this report. Refer to ANSI N45.2.10, "Quality Assurance Terms and Definitions" for definition of terms not included below.

Audit – The following modifications are applied to the definition in ANSI N45.2.10:

> Internal Audit - An activity to determine through investigation the adequacy of, and adherence to, established procedures, instructions, specifications, codes, and licensing requirements, and the effectiveness of implementation of the Duke Energy Corporation QAP.
>
> Supplier Audit - A documented activity performed in accordance with written procedures or checklists to verify, by examination and evaluation of objective evidence, that applicable elements of the supplier's QA program has been developed, documented and implemented in accordance with specified requirements.

Basic Component – See 10 CFR Part 21.

Commercial Grade Items - See 10 CFR Part 21.

Deficiency - Any condition considered to be adverse to quality including inadequacies of personnel, procedures, systems, methods, or items.

Engineering Change (Modification) - A planned change in plant design accomplished in accordance with the requirements and limitations of applicable codes, standards, specifications, licenses and predetermined safety restrictions.

Hold Point - That point in the manufacturing, preparation, development, installation and construction, inspection, or testing process that requires witness or review by qualified personnel.

Inspector - Any individual certified to the requirements identified in Table 17-1 for Regulatory Guide 1.58 who performs required inspections, tests or examinations.

Low Safety Significant – Refer to AD-EG-ALL-1221

Pre-award Survey - A documented activity performed in accordance with written procedures or checklists to verify, by examination and evaluation of objective evidence, that the supplier's QA program has been developed, documented, and implemented in accordance with specified requirements.

Quality Assurance (QA) - The planned and systematic actions necessary to provide adequate confidence that a structure, system, or component will perform satisfactorily in service.

QA Records - Those records which furnish documentary evidence of the quality of items and of activities affecting quality.

QA Requirements - Those inspection, test, examination, certification and documentation requirements which are imposed to provide objective evidence of the conformance of an item or activity to established design, engineering, standards, and code requirements.

Services - The performance by a supplier of activities such as calibration, design, investigation, inspection, nondestructive examination, software applications, and installation.

EXPLANATION OF "QUALITY ASSURANCE"

Quality Assurance (QA) as used in this document includes:

1) Performance of planned and systematic actions necessary to provide assurance of the safety and integrity of the facility.

   The QAP is founded on the principle that the line organization has the primary responsibility for quality and safety. Self-assessment practices are used to ensure the desired levels of quality and safety are achieved and maintained. Each individual is responsible to ensure the plant is operated in a safe, reliable, and efficient manner.

2) Quality verifications performed by those independent of the performers.

   When required, verification of conformance to established program requirements is accomplished by qualified individuals who do not have responsibility for performing or directly supervising the work. Nuclear Oversight (NOS) evaluates the performance, compliance, and effectiveness of plant programs, processes, and personnel. The activities of NOS are intended to detect deficiencies in the desired levels of performance and quality, communicating these conditions to those responsible for the activities, appropriate management and the Chief Nuclear Officer, and ensuring adequate action is taken to correct these conditions.

QA STANDARDS AND GUIDES

The Duke Energy Corporation QAP conforms to Appendix B of 10 CFR 50. This description of the QA Program is formatted per NUREG-0800 Section 17.3, "Quality Assurance Program Description;" however, the Duke Energy Corporation QAP continues to use the ANSI N45.2 series standards in lieu of ANSI/ASME NQA-1 and NQA-2.

Table 17-1 identifies the QA program Regulatory Guides and other NRC program guidance for which conformance is addressed in this description of the QA Program. Changes to conformance for the Regulatory Guides in Table 17-1 are controlled in accordance with 10 CFR 50.54(a) and are incorporated in this document as identified in Section 17.3.1.7.

Table 17-2 identifies additional Regulatory Guides that relate to QA program implementation but where the subject matter closely relates to UFSAR technical content. Conformance for those Regulatory Guides is site specific and addressed with each site's UFSAR.

Together, Tables 17-1 and 17-2 indicate where conformance is identified for the regulatory guidance documents referenced in NUREG-0800 Section 17.3.

Table 17-1. Conformance with QA Regulatory Guides and Industry Standards

Generic Exception:

Table 17-1 addresses Duke Energy Corporation's Conformance of the QAP to certain NRC Regulatory Guides. In so doing, specific editions of industry standards are identified for compliance with exceptions and alternatives. Those identified standards include references to other industry standards for activities. Those referenced industry standards are considered to be guidance documents for details of how activities may be accomplished. The actual standard to be used in such cases is controlled by each station's current licensing and design bases (e.g. ANSI N18.7-1976 Section 3.4.2 identifies American National Standard for Selection and Training of Nuclear Power Plant Personnel, N18.1-1971. The actual standard used is site specific as identified in Table 17-2 for Regulatory Guide 1.8.).

Regulatory Guide 1.28, Quality Assurance Program Requirements (Design and Construction)
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.28 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electric Equipment
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.30 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation)
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.33 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Table 17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.37 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage and Handling of Items for Water-Cooled Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.38 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.39, Housekeeping Requirements for Water-Cooled Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.39 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination and Testing Personnel
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.58 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Table 17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.64, Quality Assurance Requirements for the Design of Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.64 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.74, Quality Assurance Terms and Definitions
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.74 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.88, Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records
The Duke Energy program for storage of records on microfilm, dual storage or in electronic format meets the preservation requirement for the retention of QA Records. For management of electronic records, the appropriate controls on quality are summarized as follows: a) The Electronic Records Management (eRM) system does not allow deletion or modification of records. (NOTE: Authorized deletion of records per the Record Retention Rules is controlled.) b) The eRM system provides redundancy (i.e., system backup, dual storage, etc.). c) The legibility of each record is verified prior to acceptance into the eRM system. d) The media used by the eRM system is maintained to ensure the records are acceptably copied onto a new media before the manufacturer's certified useful life of the media is exceeded. This includes verification of the records so copied. e) Periodic random inspections of records are performed to verify that there has been no degradation of record quality. f) If the eRM system in use is to be replaced by new system, the records stored on the old system are acceptably converted into the new system before the old system is taken out of service. This includes verification of the records so copied. To implement those controls, Duke Energy Corporation uses the following Nuclear Information and Records Management Association (NIRMA) standards: • NIRMA TG 11-2011 "Authentication of Records and Media" • NIRMA TG 15-2011, "Management of Electronic Records," • NIRMA TG 16-2011, "Software Quality Assurance Documentation and Records" • NIRMA TG 21-2011, "Required Records Protection, Disaster Recovery and Business Continuation"

Regulatory Guide 1.88, Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.88 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.94, Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.94 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.116, Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.116 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.123, Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants
Reference table content for Generic Letter (GL) 89-02 applicable to the procurement of Commercial Grade Items and services. For the procurement of commercial grade calibration and/or testing services, Duke Energy uses NEI 14-05A, Revision 0, "Guidelines for the Use of Accreditation In Lieu of Commercial Grade Surveys for Procurement of Laboratory Calibration and Test Services." The conditions for the use of this process, consistent with NRC Safety Evaluation dated April 1, 2016 to Union Electric Company, Callaway Plant (ADAMS Accession # ML16089A167), are identified in Sections 17.3.2.4 and 17.3.2.5.

Table 17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.123, Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants
Note: Well defined and documented measurement assurance techniques or uncertainty analysis may be used to verify the adequacy of the measurement process. If such techniques are not used, the collective uncertainty of the measurement standards shall not exceed 25% of the acceptable tolerance for each characteristic being calibrated. (This is typically referred to as the four-to-one ratio.) The Duke Energy Corporation QAP conforms to Regulatory Guide 1.123 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.144 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.146, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants
The Duke Energy Corporation QAP conforms to Regulatory Guide 1.146 as identified in: • Attachment A, Brunswick Specific QAPD • Attachment B, Harris Specific QAPD • Attachment C, Robinson Specific QAPD • Attachment D, Catawba, McGuire, and Oconee Specific QAPD

Regulatory Guide 1.152 Criteria for Programmable Digital Computer System Software in Safety-Related Systems of Nuclear Power Plants
Conformance to Regulatory Guide 1.152 was not addressed during the licensing of the operating Duke Energy Corporation Nuclear plants.

Table 17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 7.10, Establishing Quality Assurance Programs for Packaging Used in the Transport of Radioactive Material
Duke Energy Corporation does not conform to Regulatory Guide 7.10. This QAPD is used to satisfy applicable Quality Assurance requirements for packaging and transportation of radioactive material.

Generic Letter 89-02, Actions to Improve the Detection of Counterfeit and Fraudulently Marketed Products
Duke Energy complies with the provisions of Generic Letter (GL) 89-02. GL 89-02 was issued in March 1989. This generic letter provides the staff's perspective on good practices in procurement and dedication and the NRC's conditional endorsement of an industry standard (EPRI NP-5652, Revision 0) on the methods of commercial-grade item procurement and dedication. Consistent with that guidance, Duke Energy complies with EPRI NP-5652, *"Guideline for the Utilization of Commercial-Grade Items in Nuclear Safety-Related Applications (NCIG-07)"*. When NRC publishes additional guidance for the dedication of Commercial Grade Items, Duke Energy may utilize that guidance in the completion documentation provided any clarifications identified by the NRC are followed. Regulatory Guide 1.164, Dedication of Commercial-Grade Items for Use in Nuclear Power Plants, Revision 0 issued June 2017 Duke Energy also complies with the provisions of Regulatory Guide 1.164, which endorses in part, with exceptions or clarifications, EPRI 3002002982, Revision 1 to EPRI NP-5652 and TR-102260, "Plant Engineering: Guideline for the Acceptance of Commercial-Grade Items in Nuclear Safety-Related Applications" with respect to acceptance of commercial-grade dedication of items and services to be used as basic components for nuclear power plants. Regulatory Guide 1.231, Acceptance of Commercial-Grade Design and Analysis Computer Programs Used in Safety-Related Applications for Nuclear Power Plants, Revision 0 issued January 2017 Duke Energy complies with the provisions of Regulatory Guide 1.231 which approves for use, with clarifications, EPRI Technical Report 1025243, "Plant Engineering: Guideline for the Acceptance of Commercial-Grade Design and Analysis Computer Programs Used in Nuclear Safety-Related Applications," Revision 1.

Quality assurance for Fire Protection from Positions 2 & 4 of Branch Technical Position CMEB 9.5-1 (Attachment to NUREG 0800 Section 9.5.1 Revision 3)
Quality assurance controls for non-Nuclear Safety Related components Important to Fire Protection are in accordance with the intent of Positions 2 & 4 of Branch Technical Position CMEB 9.5-1. Identification of items Important to Fire Protection is site specific consistent with each site's Fire Protection Program.

Table 17-2. Site Specific Response to Regulatory Guides and Industry Standards

Table 17-2 identifies additional Regulatory Guides addressing subjects related to implementation of the QAP but the implementation is site specific and addressed with each site's UFSAR.

Regulatory Guide 1.8, Personnel Selection and Training
Personnel selection and training is site specific addressing requirements beyond nuclear safety related applications.

Regulatory Guide 1.26, Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants
Quality group classifications and standards trace to the original design and construction of the nuclear power plant and therefore are site specific.

Regulatory Guide 1.29, Seismic Design Classification
Seismic design classification trace to the original design and construction of the nuclear power plant and therefore is site specific.

Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel
Nonmetallic thermal insulation for austenitic stainless steel trace to the original design and construction of the nuclear power plant and therefore is site specific.

Regulatory Guide 1.54, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants
Requirements for protective coatings applied to water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Regulatory Guide 1.143, Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants
Design of radioactive waste management systems, structures, and components installed in light-water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Regulatory Guide 1.155, Station Blackout
Addressing Station Blackout is site specific.

Table 17-2. Site Specific Response to Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 4.15, Quality Assurance for Radiological Monitoring Programs (Normal Operations) – Effluent Streams and the Environment
Requirements for radiological monitoring program (normal operations) – effluent streams and the environment is site specific.

17.3.1 MANAGEMENT

17.3.1.1 Methodology

The Chief Nuclear Officer (CNO) is the corporate executive responsible for quality assurance (QA) and is the highest level of management responsible for establishing Duke Energy Corporation's QA policies, goals, and objectives.

The QAP Policy Statement, shown in Figure 17-1, requires compliance with the QAP implementing documents in nuclear safety related matters. Organizations performing quality affecting activities are bound by this Policy Statement. The QAP has been developed in accordance with this Policy Statement. The QAP applies to individuals and organizations responsible for operating and supporting the nuclear plants in the performance of activities affecting quality (e.g., operation, maintenance, modification, and refueling). The implementing documents define responsibilities and authorities, prescribe measures for the control and accomplishment of activities for the operation of nuclear safety related structures, systems, and components and requires appropriate verification of conformance to established requirements to an extent consistent with their importance to safety. The individuals who constitute Nuclear Generation have full personal and corporate responsibility to assure that nuclear power plants are designed, constructed, tested and operated in a manner to protect the public health and safety. The comprehensive program to assure this began with initial design and continues throughout the life of the station. The Duke Energy Corporation QAP assures that the necessary quality requirements for nuclear safety related structures, systems, components and materials are achieved. All special equipment, environmental conditions, skills and processes that are determined to be nuclear safety related will be provided within the scope of the QAP– with the exception that SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document. These 50.69 LSS SSCs are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule.

Nuclear safety related structures, systems, and components (SSCs) are specified by approved design documents. Each nuclear plant has a controlled system for identifying items and activities to which the QAP applies. Controls and responsibilities for maintaining the system are prescribed in procedures.

The QAP applies to the nuclear safety related portions of the plant. The program is applied, in whole or in part, to other selected items based on the item's or activity's importance to safety. SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document. This application includes but is not limited to control and accomplishment of activities for radioactive waste, fire protection, seismically designed/restrained SSCs whose continued functions are not required during and after a seismic event, and License Renewal non-safety-related SSCs that are subject to an aging management review. Procedures provide a graded application of this QAP to non-safety related systems, components, items, and services by prescribing measures for the control and accomplishment of activities for their operation. For example, aging effects of non-safety related SSCs that were determined to be within the scope of License Renewal Aging Management Program as identified in Chapter 18 of the applicable site UFSAR, are included in the QAP for the administrative controls, corrective actions and confirmation processes described in Sections 17.3.1.6 and 17.3.2.13, Corrective Action, and 17.3.2.14, Document Control.

The QAP is founded on the principle that the line organization has the primary responsibility for quality and safety. Self-assessment practices are used to ensure the desired levels of quality and safety are achieved and maintained. This consists of each individual being involved with plant performance to ensure the plant is operated in a safe, reliable, and efficient manner. The Nuclear Oversight (NOS) Department evaluates the compliance, and effectiveness of plant programs, processes, personnel, and the line organization's self-assessment.

17.3.1.2 Organization

This section provides a generic functional description of the organization. The actual organization in-place is defined in a controlled implementing document containing the fleet operating model.

Plant specific details for the organization responsible for the safe plant operation are described in Chapter 13 of the UFSAR for each plant and in implementing documents. The term "line organization" refers to the production organization reporting to the CNO and the interfacing department staff supporting the Nuclear Generation as identified in Section 17.3.1.2.3, Department Interfaces. "Line organization" does not include the independent verification functions of the Nuclear Oversight organization.

17.3.1.2.1 Corporate Organization

The Chairman, President and Chief Executive Officer has overall responsibility for Design, Construction, Operation, and Decommissioning of generation facilities. Reporting to the Chairman, President and Chief Executive Officer is the Executive Vice President and Chief Operating Officer, who is responsible for generation and transmission including nuclear operations, nuclear development and nuclear decommissioning. Reporting to the Executive Vice President and Chief Operating Officer are the Senior Vice President and Chief Nuclear Officer (CNO), who has the overall authority and responsibility for Nuclear Generation, and the executive for Operations Support, whose responsibilities include Nuclear Decommissioning. Nuclear Decommissioning is controlled under a separate description of the quality assurance program as identified in the Defueled Safety Analysis Report for that facility.

As described in Section 17.3.1.2.3, Nuclear Generation receives support services from other organizations, reporting to the Chief Operating Officer, having responsibilities for supply chain, environmental, health and safety and non-nuclear generation activities including: fossil and hydro generation; coal combustion product strategic management; and fuels and system optimization. Services also are provided to Nuclear Generation by Group Executives, reporting to the President and Chief Executive Officer, responsible for the following: electrical distribution; support for the emergency response communications; and Information Technology Services. The interfaces with organizations providing those activities are described in Section 17.3.1.2.3. As such, the attainment of quality rests with those assigned the responsibility of performing the activity. The verification of quality is assigned to qualified personnel independent of the responsibility for performance or direct supervision of the activity. The degree of independence varies commensurate with the activity's importance to safety.

The policies described in this document are implemented through departmental program manuals and procedures, and are, thereby, available to all levels of management.

17.3.1.2.2 Nuclear Generation

Nuclear Generation has direct line responsibility for Duke Energy Corporation nuclear station operations. Nuclear Generation is responsible for achieving quality results during engineering, preoperational testing, operation, testing, maintenance and modification of the Corporation's nuclear stations and with complying with applicable codes, standards and NRC regulations. The functions of Nuclear Generation are directed by the CNO.

The CNO formulates, recommends, and carries out plans, policies, and programs related to the nuclear generation of electric power. The CNO is informed of significant problems or occurrences relating to safety and QA through established administrative procedures and participates directly in their resolution, where necessary.

Nuclear Generation is organized into three divisions. The activities of each division are directed by an executive who reports to the CNO. The divisions are Nuclear Corporate, Nuclear Oversight, and Nuclear Operations.

The CNO has the organizational flexibility to reassign responsibilities, within the limits specified in the following section, between the standard divisions to provide added focus on areas determined to need increased management attention. This flexibility includes both the ability to consolidate divisions or to identify new divisions. The actual organization in-place is defined in a controlled document containing the fleet operating model.

a) NUCLEAR CORPORATE

The senior executive(s) reports to the CNO and is responsible for Corporate Governance and providing support functions to the Nuclear Sites in the following areas: Nuclear Engineering; Nuclear Regulatory Affairs; Nuclear Support Services; Nuclear Protective Services; Nuclear Operations; Nuclear Corporate Organizational Effectiveness; Nuclear Training; and Emergency Preparedness.

The organizational structure for these functions may vary based on near-term activities and the strategic importance of our fleet initiatives, in our continuing efforts to set and achieve industry-leading operational and outage performance. These functions are primarily off-site located in the Nuclear General Office (NGO).

NUCLEAR ENGINEERING

Nuclear engineering provides broad engineering leadership and technical support to the nuclear sites with emphasis on generic issues and consistent practices, providing expertise in safety assessment with technical support in the areas of risk assessment, radiological engineering, and safety analysis; fuel management with leadership and technical support in the areas of fuel supply, spent fuel management, reactor core mechanical and thermal hydraulic analysis; the fleet electrical and procurement engineering with technical support in the areas of procurement engineering, nuclear process systems, and electrical systems and analysis; and programs and components support in the areas of steam generator inspections and maintenance, engineering programs, component engineering, material failure analysis and materials science, equipment reliability, and ASME Code inspections and testing. Nuclear engineering provides support to Site engineering for contracts and engineering related to fleet and nuclear site major project modifications.

Nuclear engineering provides record storage and document management services, technology planning, project control and technical support for information technology applications and systems such as equipment databases, applications, infrastructure, and plant process information systems.

Nuclear engineering is also responsible for Nuclear Development, which includes the licensing actions needed in support of new nuclear site development under 10 CFR Part 52. Responsibilities also include engineering oversight of contractors, site layout, staffing and program development, and operational readiness. Nuclear Development activities are controlled under a separate description of the quality assurance program as identified in the UFSAR for those facilities.

NUCLEAR MAJOR PROJECTS

Nuclear major projects provides project management for select projects critical to the success of the Nuclear Generation Department. This responsibility includes scope development estimating, planning and scheduling, project controls, timely and accurate financial reporting, contract management, and execution of assigned projects.

NUCLEAR REGULATORY AFFAIRS

Nuclear regulatory affairs provides fleet support to and governance of the site regulatory affairs and licensing activities to help improve overall fleet performance.

NUCLEAR SUPPORT SERVICES

Nuclear support services provides fleet support to the nuclear sites for laboratory, calibration, and select maintenance and refueling activities.

NUCLEAR PROTECTIVE SERVICES

Nuclear protective services provides access authorization support to the nuclear sites security organization. Nuclear protective services is responsible for governance of the site security functions, providing assistance to help improve overall fleet performance.

NUCLEAR OPERATIONS

Nuclear operations is responsible for governance of the nuclear site operating organizations, providing assistance to promote improvements to overall fleet performance.

NUCLEAR CORPORATE ORGANIZATIONAL EFFECTIVENESS

Nuclear corporate organizational effectiveness is responsible for governance of the nuclear site performance improvement organizations, providing assistance to promote improvements to overall fleet performance through the corrective action and self-assessment programs. This group also supports implementation of the corrective action and self-assessment programs by the Nuclear Corporate Organization.

NUCLEAR TRAINING

Nuclear training is responsible for governance of the nuclear site training organizations, providing assistance to promote improvements to overall fleet performance. This group also supports implementation of the training programs by the Nuclear Corporate Organization.

EMERGENCY PREPAREDNESS

Emergency preparedness is responsible for governance of the nuclear site emergency response organizations, providing assistance to promote improvements to overall fleet performance.

b) NUCLEAR OVERSIGHT

The executive for Nuclear Oversight (NOS) reports to the CNO and is located in the NGO. NOS consists of both site assigned and NGO located personnel. NOS provides oversight of the NGO, Departmental Interfaces, and the nuclear sites with QA program audits, vendor quality, and quality control. In addition, NOS coordinates the off-site review board, which provides an advisory function to senior management. NOS also provides oversight of Nuclear Development and Nuclear Decommissioning through QA program audits. The NOS executive has the authority and organizational freedom to: identify quality problems, initiate, recommend or provide solutions to quality problems through designated channels, verify the implementation of solutions to quality problems, and ensure cost and schedule do not influence decision making involving quality. This includes full access to Nuclear Development and Nuclear Decommissioning and all levels of management up to and including the Chief Executive Officer.

The NOS executive has primary ownership of the department QA program description (this document) and is responsible for interpretation and resolution of QA issues.

If significant quality problems are identified, NOS personnel have the authority to stop work as discussed in Section 17.3.1.4 pending satisfactory resolution of the identified problem.

Also reporting to the executive for NOS is Employee Concerns, which investigates concerns identified through the Employee Concerns Program to determine their validity and initiate corrective actions as appropriate. Employee Concerns also promotes the Safety Conscious Work Environment (SCWE) Program and is sensitive to SCWE concerns during investigations.

c) NUCLEAR OPERATIONS

The executive for Nuclear Operations reports to the CNO and is located in the NGO. This executive is responsible for the safe operation of the nuclear stations. Reporting to this executive are the executives for the operation of the nuclear stations.

The organization structure for each site is controlled by the site's UFSAR, which may vary from the following generic description. Reporting to the site executive for each nuclear station is a Nuclear Plant Manager who is assigned the direct responsibility for the safe operation of the facility including operations, maintenance, work management, radiation protection, chemistry, and environmental services. Also reporting to the site executive is a site Engineering manager; a site Training manager; and an Organization Effectiveness manager, typically having responsibility for regulatory affairs, emergency preparedness, performance improvement, and procedures. Each site executive also has a Security manager assigned to provide services to the site. The qualification requirements for the Nuclear Plant personnel are in accordance with the provisions of ANSI N18.1 or ANS 3.1 as identified in each site's UFSAR and Table 17-2.

17.3.1.2.3 Department Interfaces

Quality related activities performed by departments other than Nuclear Generation are identified by and conducted in accordance with controls identified in approved departmental interface agreements. The following are generic descriptions of those other corporate departments and the services they provide. These generic organizations are referred to, as appropriate, within this document; however, approved departmental interface agreements establish and define the applicability of the QAP to the services they provide.

CORPORATE COMMUNICATIONS

Corporate Communications provides support for the nuclear site emergency response organization.

ENVIRONMENTAL HEALTH AND SAFETY

Environmental, Health and Safety provides occupational safety and environmental and laboratory support services.

NUCLEAR FINANCE

Nuclear Finance provides support for the nuclear sites in the areas of financial planning.

INFORMATION TECHNOLOGY

Information Technology provides a variety of services and technical support to Nuclear Generation for information technology applications and systems such as equipment databases, applications, and infrastructure including the electronic document management system and telecommunication systems.

CUSTOMER OPERATIONS

Customer Operations provides electrical distribution and switchyard engineering, as well as providing electrical maintenance and testing support.

NUCLEAR SUPPLY CHAIN

Nuclear Supply Chain provides procurement services including receipt inspection/testing, storage, and inventory control of materials, parts, and components.

17.3.1.3 Responsibility

The primary responsibility for quality performance, including the identification and effective correction of problems potentially affecting the safe and reliable operation of the Company's nuclear facilities, resides with the line organization. The individuals who constitute Nuclear Generation have full personal and corporate responsibility to assure nuclear power plants are designed, constructed, maintained, tested and operated in a manner to protect the public health and safety; and to assure the effectiveness of the QAP.

Appropriate procedures are developed, approved by the responsible implementing manager, issued for use, and used at the location where the prescribed activity is performed, where appropriate. Managers assure that their personnel are adequately trained for their jobs and they have the experience and education required to carry out their assigned responsibilities. These managers ensure that adequate resources and procedures are available for correctly implementing the work activities. Sufficient personnel, including necessary resources, are available and trained prior to performing activities that affect quality.

Independent inspections are conducted to verify specific critical quality attributes. Individuals performing these inspections have access to necessary information to ensure that activities and equipment meet established acceptance criteria.

NOS is responsible for monitoring and auditing activities that are performed by the line organization for, or in support of, Duke Energy Corporation's Nuclear Plants and Nuclear Generation. These activities include those performed at the individual plant sites, corporate offices, and other Nuclear Generation locations. NOS performs audits to verify that applicable elements of the quality assurance and other regulatory required programs have been developed, documented and effectively implemented in accordance with specified requirements. NOS monitors supplier performance to assure implementation of the applicable quality assurance program requirements. A periodic briefing of NOS activities, along with any potential findings and recommendations, is presented to the CNO.

The CNO is responsible for ensuring that the results and effectiveness of the nuclear oversight program are regularly evaluated as discussed in Section 17.3.3.3.6, Independent Audit of QA Functions.

17.3.1.4 Authority

Personnel involved in quality activities have the authority and responsibility to stop work if they discover deficiencies in quality.

Personnel performing the QA functions have the authority and responsibility to stop unsatisfactory work and to assure the item/activity is controlled to prevent further processing, delivery, installation, or use until authorized by appropriate management.

Procedures outline the methodology for resolution of disputes involving quality and nuclear safety issues arising from a difference of opinion between identifying personnel and other groups.

17.3.1.5 Personnel Training and Qualification

Both on-site and off-site personnel who perform activities affecting quality (implement requirements of the QAP) are indoctrinated and trained such that they are knowledgeable and capable of performing their assigned tasks.

Training programs and reviews ensure that proficiency of personnel performing activities affecting quality is achieved and maintained by training, examining, and/or certifying, as appropriate.

Training programs are modified to reflect station engineering changes and changes in procedures.

Personnel training and qualification records are to be maintained in accordance with procedures.

Personnel within the Operating organization performing duties of a licensed operator are indoctrinated, trained, and qualified as required by 10 CFR Part 55 Operators' Licenses.

17.3.1.6 Corrective Action

It is the policy of Duke Energy Corporation to seek improvement in each nuclear plant's performance as well as in the performance of supporting Departments. Duke Energy Corporation has established a corrective action process whereby all personnel are expected to assure conditions adverse to quality are promptly identified, controlled, and corrected. Individuals are encouraged to voluntarily report events, near misses, and potential problems. In the case of significant conditions adverse to quality, the process assures that the cause of the condition is determined and action be taken to preclude repetition. This process also provides for trending of problems to detect adverse trends in quality performance, including reporting of results to appropriate levels of management.

Management will emphasize to all levels in the organization the importance of identifying and effectively correcting situations that can adversely affect human and equipment performance. An important aspect of this program is the assignment of qualified personnel to accurately evaluate equipment/human performance problems, implement appropriate corrective actions, and verify corrective action adequacy.

Management is responsible for fostering a positive environment that encourages the self-identification of adverse conditions and trends. This includes assuring the process is administered to correct the problem rather than to establish blame or fault.

License Renewal non-safety-related SSCs that are subject to an aging management review are included in the scope of the corrective action program.

Section 17.3.2.13, Corrective Action provides additional detail.

17.3.1.7 Regulatory Commitments

The operation of nuclear plants is accomplished in accordance with the U.S. Nuclear Regulatory Commission (NRC) regulations specified in Title 10 of the U.S. Code of Federal Regulations.

The operation of the Company's nuclear power plants is in accordance with the terms and conditions of the facility operating license issued by the NRC.

The QAP provides for compliance with QA regulatory guides and the related codes and standards as identified in Table 17-1, Conformance with QA Regulatory Guides and Industry Standards.

The requirements of this section (17.3) may provide additional details for implementation of exceptions to these Regulatory Guides and codes and standards.

Changes to the description of the QAP contained in this document are controlled in accordance with 10 CFR 50.54(a).

Table 17-2, Site Specific Response to Regulatory Guides and Industry Standards, identifies additional Regulatory Guides that relate to implementation of the QAP but the implementation is site specific and controlled with each site's UFSAR in accordance with 10 CFR 50.59.

17.3.2 PERFORMANCE/VERIFICATION

17.3.2.1 Methodology

Personnel performing work activities are responsible for achieving the acceptable level of quality.

Personnel performing verification activities are responsible for verifying the achievement of acceptable quality.

Work is accomplished and verified using instructions, procedures, or appropriate means that are of a detail commensurate with the activity's complexity and importance to safety. The implementing manager is responsible to ensure instructions and procedures provide adequate detail for achieving an acceptable level of quality.

Criteria that define acceptable quality are specified in procedures and/or other documents, and verification, when required is performed against these criteria.

17.3.2.2 Design Control

In order to provide for the continued safe and reliable operation of a nuclear station's nuclear safety related structures, systems and components, design control measures commensurate with those applied to the original design are implemented during the operational phase to assure that the quality of such structures, systems and components is not compromised by engineering changes.

Nuclear Engineering is responsible for design activities during the operational phase of nuclear stations to Nuclear Generation. Nuclear Engineering will assure that the organization performing design has access to pertinent background information, including an adequate understanding of the requirements and intent of the original design, and that the organization has demonstrated competence in applicable design areas.

Procedures and instructions for design control during the operational phases for nuclear safety related items provide controls to assure the design is performed in accordance with approved criteria, and that deviations and nonconformances are controlled.

Procedures identify the responsibilities of the various individuals/organizations involved in nuclear safety related engineering changes. The assignment of responsibility for the evaluation and design of a particular engineering change to a specific individual/organization is documented. Procedures addressing the control, including the review, approval, release, and distribution of engineering changes, address the communication of information between internal and external individuals/organizations and, where appropriate, require documentation of such communications.

The procedures include measures to assure that the design selected to accomplish a necessary or desirable change does not create "new" problems in off-normal modes of operation or in adjacent inter-tied systems. For each proposed nuclear safety related engineering change, the individual/organization assigned responsibility for evaluation and design of the engineering change considers the following in the design of the engineering change:

a. Necessary design analyses, e.g., physics, stress, thermal, hydraulic, accident, etc.
b. Compatibility of materials.
c. Accessibility for operation, testing, maintenance, in-service inspection, etc.
d. Necessary installation and periodic inspections and tests, and acceptance criteria therefore.
e. The suitability of application of materials, parts, components, and processes that are essential to the function of the structure(s), system(s) and/or component(s) to be modified.
f. Materials, parts, and equipment which are commercial grade items or which have been previously approved for a different application are evaluated for suitability prior to selection.

Engineering changes are then executed in accordance with approved checklists, instructions, procedures, drawings, etc., appropriate to the nature of the work to be performed. These checklists, instructions, procedures, drawings, etc., include criteria for determining the acceptability of the engineering change.

Any errors or deficiencies found in the design process or the nuclear safety related design itself are documented and corrected using the corrective action program.

Prior to a structure, system, or component that has been modified by engineering change being declared operable and returned to service, the procedures governing the operation are reviewed and revised as necessary. If the engineering change significantly alters the function, operating procedure, or operating equipment, then additional training is administered as necessary.

Adequate identification and retrievable documentation of station engineering changes is retained for the life of the station.

Engineering changes are reviewed to determine whether or not the modification is a change in the facility as described in the UFSAR, involves a change to the Technical Specifications, or requires a license amendment in accordance with 10 CFR 50.59(c)(2). Engineering changes which are determined to require a license amendment are reviewed by the On-Site Review Committee and must be authorized by the NRC prior to implementation.

17.3.2.3 Design Verification

Procedures require that the adequacy of nuclear safety related designs and design changes be verified by the performance of design reviews, alternate calculations, or qualification testing. The control measures specified in the plan for control of design verification activities are as follows:

a. Personnel responsible for design verification do not include the original designer or the designer's immediate supervisor unless the immediate supervisor is the only one capable of verifying the design, in which case additional requirements apply as identified below.
b. Procedures identify the positions or organizations responsible for design verification and define their authority and responsibility. Procedures also provide guidelines as to the method of design verification to be used. Unless otherwise specified, design verification is performed by the method of independent design reviews and includes verification that UFSAR commitments have been addressed.
c. Qualification tests to verify the adequacy of the design are performed using the most adverse specified design conditions.
d. Design changes are reviewed to assure that design parameters are defined and that

inspection and test criteria are identified.

e. Design verification is completed prior to relying upon the component, system or structure to perform its function or before its installation becomes irreversible.

The use of the originator's immediate supervisor for verification is:

1) restricted and justified to special situations where the immediate supervisor is the only individual capable of performing the verification
2) the need is individually documented and approved in advance by the supervisor's management and
3) the frequency and effectiveness of the supervisor's use as design verifier are independently verified to guard against abuse.

The individuals assigned to perform the design verification of a nuclear safety related document have full authority to withhold approval of the document until every question concerning the work has been resolved. If required, the matter can be carried up to the CNO for resolution.

17.3.2.4 Procurement Control

Duke Energy Corporation maintains a program for supplier evaluation, results of supplier evaluation, surveillance of suppliers, supplier furnished records, certificates of conformance, effectiveness of supplier quality control, and the purchase of spare or replacement parts. The Duke Energy Corporation QAP requires the control of nuclear safety related items or services purchased from a supplier, sub-supplier, or consultant through appropriate processes and specific procurement documents.

Procedures identify the responsibilities and requirements for the control of procurement documents and ensure that purchased material and services are of acceptable quality. Procurement of QA items is to the quality program requirements in effect at the time of purchase.

Nuclear safety related material, equipment and services procured as basic components may only be procured from qualified suppliers. Supplier qualification is accomplished by NOS evaluation of the supplier QA program. An audit or pre-award survey is performed by NOS when required. The audit or pre-award survey is carried out in accordance with a comprehensive audit checklist to determine the ability of the supplier QA program and manual(s) to meet applicable criteria of 10 CFR 50, Appendix B; 10 CFR 21; the ASME Code, when required, and any other codes and standards determined to be appropriate for the prospective scope of supply.

SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document. These 50.69 LSS SSCs are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule.

The above requirements apply to procurement of services and items as basic components, including obtaining a Commercial Grade Item dedicated as basic component from an approved third party dedicator. The remainder of this section addresses alternate requirements for purchase of Commercial Grade Items or services.

17.3.2.4.1 Commercial Grade Dedication

When nuclear safety related items/services are not supplied as a basic component and meet the definition of Commercial Grade Item, the item may be procured without the performance of a supplier qualification audit or the existence of a documented supplier QA program. These Commercial Grade Items used in nuclear safety related applications require evaluation, dedication and approval by Nuclear Generation personnel. Commercial Grade Dedication is performed using NRC endorsed industry standards EPRI NP-5652, EPRI Technical Report 102260, EPRI 3002002982, and EPRI Technical Report 1025243 consistent with the NRC exceptions or clarifications identified in GL 89-02, RG 1.123, RG 1.164, and RG 1.231 providing the endorsements. Supplier selection for Commercial Grade Items is the responsibility of the responsible engineering personnel or designated supply chain personnel as identified in procedures. These items are subject to the same verification and checking process for suitability of application as other nuclear safety related items.

17.3.2.4.2 Commercial Grade Dedication of Laboratory and Testing Services

As identified in NEI 14-05A, commercial grade calibration or testing services may be procured from commercial laboratories based on the laboratory's accreditation to ISO/IEC-17025 by an Accreditation Body (AB) which is a signatory to the International Laboratory Accreditation Cooperation (ILAC) Mutual Recognition Arrangement (MRA) without performing commercial grade surveys as part of commercial grade dedication provided all of the following are met:

1. A documented review of the supplier's accreditation is performed and includes a verification of the following:
    a. The calibration or test laboratory holds accreditation by an accrediting body recognized by the ILAC MRA. The accreditation encompasses ISO/IEC-17025:2005, "General Requirements for the Competence of Testing and Calibration Laboratories."
    b. For procurement of calibration services, the published scope of accreditation for the calibration laboratory covers the needed measurement parameters, ranges, and uncertainties.
    c. For procurement of testing services, the published scope of accreditation for the test laboratory covers the needed testing services including test methodology and tolerances/uncertainty.
2. The purchase documents require that:
    a. The service must be provided in accordance with their accredited ISO/IEC-17025:2005 program and scope of accreditation.
    b. As found calibration data must be reported in the certificate of calibration when calibrated items are found to be out-of-tolerance. (for calibration services only)
    c. The equipment/standards used to perform the calibration must be identified in the certificate of calibration. (for calibration services only)
    d. The customer must be notified of any condition that adversely impacts the laboratory's ability to maintain the scope of accreditation.
    e. Additional technical and quality requirements, as necessary, are specified for verification at receipt based upon a review of the procured scope of services, which may include, but are not necessarily limited to, tolerances, accuracies, ranges, and industry standards.
3. It is validated, at receipt inspection as part of the commercial grade dedication process, that the laboratory's documentation certifies that:
    a. The contracted calibration or test service has been performed in accordance with their ISO/IEC-17025:2005 program, and has been performed within their scope of accreditation, and
    b. The purchase order's requirements are met.

17.3.2.5 Procurement Verification

Duke Energy Corporation procurement documents are prepared, reviewed, approved, and controlled in accordance with procedures to assure that requirements are correctly stated, inspectable, verifiable, and controllable, and there are adequate acceptance/rejection criteria. Procurement documents are reviewed by personnel knowledgeable in applicable technical and quality requirements, and documentary evidence of that review and approval is retained and available for verification. As required by procurement criteria, in order to assure that material and equipment are fabricated in accordance with applicable requirements, supplier reviews are performed by Vendor Quality. Those reviews may include witnessing of tests, observation of fabrication checkpoints, and documentation review.

Receipt inspections are performed by qualified inspectors in accordance with procedures to assure that:

1. Materials, equipment, or components are properly identified and correspond with associated documentation.
2. Inspection records or certificates of conformance attesting to the acceptance of materials, equipment, and components are completed and are available prior to installation or use.
3. Materials, equipment, and components are inspected and judged acceptable in accordance with predetermined inspection instructions prior to installation or use.
4. Items not meeting applicable requirements are identified and controlled until proper disposition is made.

The process ensures that required documentation of compliance is received and available on site and procurement, inspection, and testing requirements are satisfied before the item is placed in service.

As identified in Section 17.3.2.4.2, specific to the commercial grade dedication of Calibration Testing and Laboratory Services, receipt inspection verifies that:

- The laboratory's documentation certifies that:
    - contracted calibration or test service has been performed in accordance with their ISO/IEC-17025:2005 program,
    - has been performed within their scope of accreditation, and
    - the purchase order's requirements are met.
- Additional technical and quality requirements are met.

17.3.2.6 Identification and Control of Items

Procedures require spare or replacement parts to be subject to QAP controls, codes and standards, and technical requirements which ensure they are suitable for their intended service. Items accepted or released are identified as to their inspection status prior to forwarding them to a controlled storage area or releasing them for installation or further work. Bulk items will not require individual accept tags; however, status of unacceptable bulk items will be so indicated.

Identification requirements for materials, parts and components important to nuclear safety are stated in specifications, drawings and purchase documents.

Control of material, parts and components is governed by approved procedures.

Following QA receipt inspection, materials, parts and components which are determined to be acceptable are assigned an identifying designation such as a unique tracking number in order to provide traceability of each item. This traceability is maintained for nuclear safety related items.

In the event that the identification of an item becomes lost or illegible, the item is considered nonconforming and not utilized until proper resolution of the nonconformance.

Consumables utilized in nuclear safety related structures, systems and components are subject to appropriate controls as described in procedures.

17.3.2.7 Handling, Storage, and Shipping

Procedures utilized by suitably trained individuals define requirements for the control of the handling, storage, and shipping of safety-related items. These procedures require measures to be taken to ensure special handling, storage, cleaning, packaging, shipping, and preservation requirements are established to control these activities in accordance with design and specification requirements to preclude damage, loss or deterioration by environmental conditions such as temperature or humidity. Nuclear safety related materials, parts and components are handled, stored, issued and shipped in such a manner that the serviceability and QA traceability of an item is not impaired.

Nonconforming items are identified, segregated, or otherwise controlled in such a manner as to preclude their inadvertent substitution for and use as conforming materials parts and components.

17.3.2.8 Test Control

The QAP addresses both preoperational and periodic (surveillance) testing. The program requires that such testing associated with nuclear safety related structures, systems and components demonstrate that the items will perform satisfactorily in service. Testing activities are accomplished in accordance with approved, written procedures. Testing schedules are provided and maintained in order to assure that all necessary testing is performed and properly evaluated on a timely basis. Test controls include requirements on the review and approval of test procedures, and on the review and approval of changes to such procedures, as discussed in Section 17.3.2.14, Document Control.

Modifications, repairs, and replacements are accomplished in accordance with the original design and testing requirements or acceptable alternatives.

17.3.2.9 Measuring and Test Equipment Control

The organizations performing nuclear safety related work activities have the responsibility to assure the required accuracy of tools, gauges, instruments, radiation measuring equipment, non-destructive testing equipment and other measuring and test devices affecting the proper functioning of nuclear safety related structures, systems and components and that a program of control and calibration for such devices is provided – with the exception that SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document. These 50.69 LSS SSCs are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule.

Procedures define requirements for the control of measuring and test equipment (M&TE) used. These procedures include requirements to establish procedures for the calibration technique and frequency, maintenance, and control of measuring and test equipment. The requirements include the following:

a. M&TE is assigned permanent, identifying designations. M&TE is identified and traceable to the calibration test data.

b. M&TE is calibrated at prescribed intervals against certified equipment having known, valid relationships to nationally recognized standards or where national standards do not exist, provisions are established to document the basis for the calibration. The calibration interval is based on the applicable manufacturer's recommendations. If experience shows that the manufacturer's recommendations are not appropriate, the calibration interval is changed as necessary. One or more of the following may be used to adjust intervals: 1. Technical Specifications; 2. Required accuracy; 3. Intended use;

   4. Frequency of usage; 5. Stability characteristics; 6. Other conditions affecting measurement. In lieu of specified intervals, infrequently used M&TE may be calibrated immediately before and after use.

c. Status of calibration for M&TE is provided through the use of tags, stickers, labels, routing cards, computer programs, or other suitable means. The status indicators indicate the date recalibration is due or the frequency of recalibration.

d. M&TE failing to meet calibration specifications is identified through the use of tags, stickers, labels, routing cards, computer programs, or other suitable means, showing the date of rejection, the reason for rejection and the identification of the individual rejecting the device. "Accepted" and "Rejected" calibration identification is sufficiently different to preclude confusion between them.

e. Items and processes determined to be acceptable based on measurements made with M&TE that subsequently cannot be demonstrated to meet calibration specifications are re-evaluated to determine the validity of previous inspections and test results and the results of the evaluation documented.

f. M&TE is stored under conditions which are in accordance with, or more conservative than, the applicable manufacturer's recommendations.

g. M&TE is issued under the control of responsible personnel so as to preclude unauthorized use.

h. M&TE is shipped in a manner that is in accordance with, or more conservative than, the applicable manufacturer's recommendations.

i. Records are maintained for each item of M&TE identifying the device designation, the calibration frequency and specifications. Records are maintained reflecting current calibration status, the date of calibration, the date the next calibration is due, and the identification of the individual who was responsible for performing the calibration.

j. As a rule, the calibration program achieves a minimum ratio of 4-to-1 calibration standard accuracy to measuring and test equipment accuracy is used. However, well defined and documented measurement assurance techniques or uncertainty analysis may be used to verify the adequacy of the measurement process. See site specific requirements for other exceptions to the 4:1 rule.

M&TE is selected to assure accurate measurement (i.e., to overcome inherent inaccuracies associated with environment, human error, equipment, etc.).

17.3.2.10 Inspection, Test, and Operating Status

Procedures define requirements for the identification and control of the inspection, test, and operating status of safety-related structures, systems, and components, to assure that equipment operating status is clearly evident, and to prevent inadvertent operation of nuclear safety related structures, systems and components which, if operated, could cause damage to other equipment/systems or to personnel

These measures include the use of checklists, computer programs, logs, stickers, tags, labels, record cards, and test records to indicate the acceptable operating status of installed equipment. Where appropriate, an independent verification of the correct implementation of such identification measures is performed.

When tags, labels or stamps are utilized for the identification of equipment status, the issuance and removal thereof is documented in order to assure proper control of such identification measures. Also, procedures require that the operability of an item removed from operation for maintenance or testing be verified prior to returning the item to normal service.

Selected plant procedures and subsequent revisions receive separate technical review to ensure required inspections, tests, and other critical operations are included.

17.3.2.11 Special Process Control

Procedures define requirements for the control of special processes, such as welding, heat treating, nondestructive examination (NDE), coatings, and chemical cleaning when the performance of such processes affects the proper functioning of nuclear safety related structures, systems, and components.

Procedures require that special processes be performed by qualified personnel using proper equipment and in accordance with written qualified procedures. These personnel and procedures are to be qualified in accordance with applicable codes, standards, and specifications as described in procedures.

Qualification records of special process procedures and personnel performing special processes are maintained and available for verification.

17.3.2.12 Inspection

Procedures define requirements for an inspection program to verify conformance to performance and quality requirements specified for nuclear safety related structures, systems, and components. SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document. These 50.69 LSS SSCs are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule.

Inspections are performed by personnel who are not directly responsible for performing or supervising the activity being inspected. Inspection personnel are qualified in accordance with applicable codes and standards, and their qualifications and certifications are maintained current.

Inspections are performed in accordance with procedures or other documents, which provide for the following:

1. Identification of individuals or groups responsible for performing the inspections
2. Identification of characteristics and activities to be inspected
3. Acceptance criteria
4. Inspection techniques
5. Recording the results of the inspection, review of the results, and identification of the inspector
6. Indirect control by monitoring of processing methods, equipment, and personnel when direct inspection is not possible

Mandatory inspection hold points are included in the documents addressing the activities being performed, as necessary and work does not proceed until satisfactory completion of the required inspection.

When acceptance criteria are not met, the condition will be documented in accordance with the corrective action program procedures and work does not proceed until satisfactory disposition of any item not meeting the acceptance criteria and satisfactory completion of any required re-inspection.

Modification, repairs, and replacements are inspected in accordance with the original design and inspection requirements or acceptable alternatives.

17.3.2.13 Corrective Action

Station personnel are responsible for the implementation of the QAP as it pertains to the performance of their activities. Specific to this responsibility is the requirement for informing the responsible supervisory personnel and/or for taking appropriate corrective action whenever any deficiency in the implementation of the requirements of the program is determined.

Procedures define requirements for a corrective action program that charges personnel working at or supporting the nuclear plants with the responsibility to identify adverse conditions (including conditions adverse to quality). Conditions adverse to quality are identified through inspections, assessments, tests, checks, and review of documents. Procedures require that conditions adverse to quality be corrected. In the case of significant conditions adverse to quality, the procedures assure that the cause of the condition is determined and action be taken to preclude repetition.

Significant conditions adverse to quality are reported to appropriate management for review and evaluation.

Violations of Technical Specifications, safety limit violations, and other reportable events are investigated to correct the condition and to support the reporting requirements of 10 CFR 50.73(b). Reports of such investigations are reviewed by a knowledgeable individual other than the individual who prepared the report.

Periodic reviews and evaluations of adverse conditions are performed to identify and correct adverse trends.

17.3.2.14 Document Control

Procedures define requirements for the development, review, approval, issue, use, revision, and control of documents. These procedures define the scope of which documents are to be controlled. These activities include measures to control the issuance of documents such as, instructions, procedures, and drawings, and changes thereto, which prescribe activities affecting quality.

A document control system has been established to identify the current revision number of instructions, procedures, specifications, and drawings. This system includes provisions to ensure that superseded documents are controlled to prevent inadvertent use.

Controlled documents are to be distributed to and used by the person performing the activity in accordance with procedures. These controlled documents are distributed electronically. Hardcopy distribution, if required, is by distribution indices.

Procedures require the identification of those individuals or organizations responsible for reviewing, approving, and issuing documents and revisions thereto. The required reviews include reviews verifying that changes to the procedures, tests or experiments do not involve a change in the Technical Specifications or otherwise require prior NRC approval.

In addition to procedures and engineering documents (e.g. specifications and drawings), the following are considered to be controlled documents:

- The station Facility Operating License and Technical Specifications
- Updated Final Safety Analysis Reports
- Process Control Program
- Offsite Dose Calculation Manual
- Radiological Effluent Controls of the UFSAR, and radwaste treatment systems

Procedures established for operational phase activities include:

1. Operating Procedures
2. Alarm Responses
3. Radiation Protection Procedures
4. Maintenance Procedures
5. Instrument Procedures
6. Chemistry Procedures
7. Process Control Program Implementing Procedures
8. Periodic Test Procedures
9. Abnormal Procedures
10. Emergency Procedures
11. Emergency Response Procedures
12. License Renewal Aging Management Program

In lieu of the two year procedure review prescribed by ANSI N18.7-1976 Section 5.2.15, Duke Energy Corporation has programmatic controls in place to continually identify procedure revisions which may be needed to ensure that procedures are appropriate for the circumstance and are maintained current. These controls include the following:

- The procedure revision process includes a mechanism for procedure users to request changes to the procedures.
- The modification process requires that procedures be reviewed to determine the effects of a planned plant modification.
- Procedures are reviewed for adequacy based upon lessons learned from the operating experience program, training programs, emergency plan reviews, drills and exercises, and normal use.
- The work control process includes pre job review process and a procedure adherence policy requiring that, if procedures cannot be implemented as written, the job be stopped and the procedure be revised or the situation resolved prior to work continuing.

The line organization performs a biennial self-assessment of the procedure process to assure their procedures are maintained current. This assessment includes a requirement to evaluate potential adverse trends in the procedure change process to ensure that changes required to maintain procedures current and technically accurate are being implemented in a timely manner.

17.3.2.15 Records

Each nuclear station is required to maintain adequate identifiable and retrievable QA records. The QAP requires that sufficient records be maintained to provide documentary evidence of the quality of items and the accomplishment of activities affecting quality.

Procedures define requirements for the identification, collection, and storage of quality assurance records.

The program for storage of records on microfilm, dual storage or in electronic format meets the preservation requirement for the retention of QA Records.

Media used for retention of records include (but are not limited to): microfilm, compact disk recordable (CD-R), and magnetic media including videotape, computer tape, optical disks, and hard disk storage. Electronic records retention is an integral component of the Record Retention Program, approved by the management position responsible for Nuclear Generation Department records. The format used must be capable of producing legible, accurate, and complete documents supporting the required retention period. Electronic approval and authorization procedures are established to assure that only those persons authorized grant the required approvals.

For creation and maintenance of on-line electronic records, Duke Energy Corporation follows the Nuclear Information and Records Management Association (NIRMA) Technical Guides as identified in Table 17-1, Conformance with QA Regulatory Guides and Industry Standards.

There is no requirement to convert records stored on media including hardcopy, microfilm, compact disk recordable (CD-R), and magnetic media including videotape, computer tape, and optical disks to on-line electronic records. Those records may be maintained in their current form as long as retrieval technology and media life support the continued use of the media. If records stored on one media are to be converted to a new media, the records stored on the old system's media are acceptably converted into the new system before the old system is taken out of service. This includes verification of the records so copied are complete and accurate in the new system.

Records are identifiable and retrievable through the use of indexes and filing systems, which are required by the program.

Procedures are required to be developed to indicate responsibilities and retention periods.

The actual retention times for the various QA records are in accordance with corporate retention policies. The development of these retention policies includes consideration of applicable requirements, including those of the Code of Federal Regulations, a station's Technical Specifications, established national codes and standards, and regulatory guidance as listed in Table 17 1, Conformance with QA Regulatory Guides and Industry Standards.

The following is a list of typical QA Records retained for the operational phase:

1. Records and drawing changes reflecting facility design modifications made to systems and equipment described in the Final Safety Analysis Report. These include: drawings, design specifications, calculations, design analyses, and vendor documents for nuclear safety related structures, systems and components.
2. Records of new and irradiated fuel inventory, fuel transfers and assembly burn-up histories.
3. Radiation monitoring records, including records of radiation and contamination surveys.
4. Personnel radiation exposure records.
5. Records of radioactive releases and waste disposal, records of gaseous and liquid radioactive material released to the environs.
6. Records of component cyclic or transient limits established for the reactor coolant system, reactor vessel, and secondary coolant system.
7. Records of the qualifications, experience and training of appropriate station personnel
8. Records of quality control inspections.
9. Records of reviews performed for changes made to procedures or safety related SSCs or reviews of tests and experiments pursuant to 10 CFR 50.59. While SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document, as these 50.69 LSS SSCs are no longer subject to the requirements of 10

CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule. The exempted regulations do not include 10 CFR 50.59. Therefore, changes to SSCs considered LSS per 10 CFR 50.69 remain subject to the review requirements of 10 CFR 50.59.

10. Changes to station procedures; including review and approval documentation.
11. Records of meetings of the off-site review committee.
12. Records of Independent Review. These records include on-site review committee meeting minutes.
13. Records of reactor tests and experiments.
14. Records of in-service inspections performed pursuant to Technical Specifications and 10 CFR 50.55a(g).
15. Records of the service lives of all safety-related snubbers (required by Technical Specification) including the data at which the seal service life commences and associated installation and maintenance records.
16. Records of analyses required by the Radiological Environmental Monitoring Program that would permit evaluation of the accuracy of the analysis at a later date.
17. Records of secondary water sampling and water quality.
18. Records of reviews performed for changes made to the Off-Site Dose Calculation Manual, the Process Control Program, and Radwaste Treatment Systems.
19. Isotopic and physical inventory records of special nuclear materials.
20. Nuclear safety related preoperational testing records.
21. Records such as vendor documentation packages and inspection reports, piping isometric drawings, welding records, etc. compiled during the design and construction of a nuclear station.
22. Approved purchasing documents for items requiring QA certification.
23. Purchase specifications.
24. Records of special processes affecting nuclear safety related structures, systems and components.
25. Records of off-site environmental surveys.
26. Records of environmental qualification.
27. By-product material inventory records.
28. Radioactive liquid effluent, gaseous effluent, and gaseous process monitoring instrumentation alarm/trip setpoints.
29. Records of reviews performed for changes made to Radiological Effluent Controls.
30. Records of reviews performed on the Fire Protection Program and implementing procedures.
31. Audit reports and required written responses.
32. Records and logs of facility operation covering time interval at each power level, including: switchboard record, reactor operator logbook, and shift supervisorlogbook.
33. Records and logs of principal maintenance activities, inspections, repair and replacement of principal items of equipment related to nuclear safety.
34. Reports of all reportable and other significant events.
35. Records of surveillance activities, inspections, and calibrations required by Technical Specifications.
36. Records of radioactive shipments.
37. Records of sealed source and fission detector leak tests and results.
38. Records of annual physical inventory of all sealed source material of record.
39. Calibration standard records and Measuring and Test Equipment (M&TE) calibration records.

Dry cask storage records pertaining to the design, fabrication, erection, testing, maintenance, and use of structures, systems, and components important to safety must be maintained for the life of the storage module.

17.3.3 SELF-ASSESSMENT

17.3.3.1 Methodology

Each site executive and the CNO are responsible for ensuring that an environment exists for a strong assessment program at each nuclear site and within Nuclear Generation, respectively.

The overall objective at Duke Energy Corporation is to encourage ownership, involvement, and dedication by each individual supporting Nuclear Generation. This involves continually looking for ways to improve the overall performance and safety at each plant. This approach of identifying and correcting conditions early, requires active support by management and employees.

The Duke Energy Corporation self-assessment process includes the line organization self-assessment activities, independent review activities, and an independent assessment process implemented by NOS that encompasses internal and supplier audits. NOS may perform in-plant reviews and other independent assessments requested by the CNO.

The managers of line organizations are responsible for ensuring that self-assessment activities and processes are implemented within their functions to promote continuous improvements. A process of self-assessment is an attitude by personnel that the Duke Energy Corporation Nuclear Generation is improving on a continual basis. This process, along with an effective corrective action program, ensures that conditions are identified early, corrected promptly and effectively before becoming significant quality or safety problems.

The independent review activities are discussed in Section 17.3.3.2.

As directed by the CNO, an off-site review board periodically performs independent reviews of matters involving the safe operation of Duke Energy's fleet of nuclear power plants. The review addresses matters that plant and corporate management determine warrant special attention, such as plant programs, performance trends, employee concerns, or other matters related to safe plant operations. The review is performed by a team consisting of personnel with experience and competence in the activities being reviewed, but independent (from cost and schedule considerations) from the organizations responsible for those activities. The review is supplemented by outside consultants or organizations as necessary to ensure the team has the requisite expertise and competence. Results are documented and reported to responsible management.

The independent assessment process is to confirm to management that activities affecting quality comply with the QAP and that the QAP has been implemented effectively. The assessment activities are performed in accordance with instructions and procedures by organizations independent of the areas being assessed. This process is discussed in detail in Section 17.3.3.3.

17.3.3.2 Independent Review

The independent review function is provided through a combination of the On-Site Review Committee, Nuclear Oversight, and the line organization executing quality assurance program required reviews as follows:

- Reviews of the independent review subjects are performed by the On-Site Review Committee as described in Section 17.3.3.2.1, On-Site Review Committee.
- Reviews of audit reports, identified in ANSI N18.7-1976 Section 4.5, are performed by management of the audited area and Nuclear Oversight instead of the independent review function.

- Reviews of the corrective actions for significant conditions adverse to quality are performed by appropriate management. Collectively, the On-Site Review Committee and the NOS audit function perform the independent review, identified in ANSI N18.7-1976 Section 5.2.11, for significant conditions adverse to quality.

17.3.3.2.1 On-Site Review Committee

The On-Site Review Committee is responsible to the Nuclear Plant Manager for advice on all plant-related matters concerning nuclear safety. The requirements for personnel, committee composition, meeting frequency, quorum and meeting records are identified in procedures. A general description of these areas is included below. (Note: Each plant may name this function differently. Regardless of the name, these requirements are met.)

In discharging its independent review responsibilities, the On-Site Review Committee keeps safety considerations paramount when opposed to cost or schedule considerations. Should a voting member at a particular meeting have direct responsibility for item under review where a conflict of such considerations is likely, that member is replaced (to fill the quorum) by another voting member not having such potential conflict.

17.3.3.2.1.1 Composition

The On-Site Review Committee is comprised of a minimum number of members as designated by the Plant Manager and detailed in procedures. All members are qualified in accordance with procedure requirements that meet site Technical Specifications. Membership includes representation from at least the following disciplines: Operations, Maintenance, Engineering, Radiation Protection and Chemistry. The On-Site Review Committee collectively has, or has access to, the experience and competence necessary to review the areas of (1) nuclear power plant operations, (2) nuclear engineering, (3) chemistry and radiochemistry, (4) metallurgy, (5) nondestructive testing, (6) instrumentation and control, (7) radiological safety, (8) mechanical and electrical engineering, (9) administrative controls and quality assurance practices, and (10) other fields associated with the unique characteristics of the plant. Consultants may be utilized to provide expert advice as needed.

Alternate chairmen and members may be appointed by the Nuclear Plant Manager to serve on a permanent or temporary basis.

17.3.3.2.1.2 Meetings

The On-Site Review Committee meets commensurate with the scope of activities, but minimal frequency requirements are specified in procedures.

Rules for a quorum are established and adhered to. However, no more than a minority of alternates may participate as voting members at any one time.

17.3.3.2.1.3 Review Topics

In performing its independent review responsibilities, the On-Site Review Committee reviews:

(1) Proposed changes to the facility as described in the UFSAR. This review is to confirm that the regulatory required written evaluation provides adequate bases for the determination that the change does not require a license amendment.

(2) Proposed changes to procedures as described in the UFSAR and tests or experiments not described in the UFSAR. This review is to confirm that the regulatory required written evaluation provides adequate bases for the

determination that the test or experiment does not require a license amendment.

(3) Proposed Technical Specifications changes and license amendments, except in those cases where the change is identical to a previously reviewed proposed change.

(4) Licensee Event Reports that are required to be made to the NRC. This review includes results of any investigations made and recommendations resulting from such investigations to prevent or reduce the probability of recurrence of the event.

(5) Any other matter related to nuclear safety requested by the Site executive, Plant Manager, selected by On-Site Review Committee members, or referred for review by other organizations.

In addition to reviews of license amendments addressed by (3) above, the On-Site Review Committee should be informed of changes to Site documents that are required to be reported to the NRC. When appropriate, the On-Site Review Committee conducts reviews of such changes to confirm the changes have been prepared and internally approved within license obligations and can be effectively implemented. These documents include the Offsite Dose Calculation Manual (ODCM), the Process Control Program (PCP), the Emergency Plan, and the Security Plan.

The On-Site Review Committee may establish subcommittees or designate organizational units to carry out the reviews. The subcommittees or organizational units report results of reviews for full committee consideration and may recommend items for full committee review as warranted. The reviews by the On-Site Review Committee recognize that the QA Program requires independent technical reviews to be completed including, but not limited to, design verification and reviews of procedures. Those independent technical reviews are conducted commensurate with the importance to nuclear safety of the item or activity. In conducting its review, the On-Site Review Committee is confirming the changes have been prepared and internally approved within license obligations and can be effectively implemented, not re-performing completed technical reviews.

The On-Site Review Committee conducts special reviews and investigations as requested by the Site executive or Nuclear Plant Manager.

17.3.3.2.1.4 Authority

The On-Site Review Committee:

- Recommends to the Nuclear Plant Manager approval or disapproval of items reviewed.
- Renders determinations with regards to whether items (1) through (3) adversely affect safety and if a Technical Specification change or NRC review is required.
- Provides written notification to the Site executive of any disagreements between the On-Site Review Committee and the Nuclear Plant Manager.

The On-Site Review Committee advises the Nuclear Plant Manager on matters related to safe operation and overall performance. The Committee has authority to obtain access to records and personnel as needed to conduct reviews.

17.3.3.2.1.5 Records

The On-Site Review Committee maintains written minutes of each Committee meeting, to include identification of items reviewed, and decisions and recommendations of the Committee. Copies of the minutes are provided to the Site executive, and to other onsite and offsite management responsible for the areas reviewed as necessary. On-Site Review Committee records are retained according to Section 17.3.2.15.

17.3.3.3 Independent Assessment

NOS is responsible for conducting independent assessments of functions and activities affecting the nuclear programs at Duke Energy Corporation locations. NOS monitors and assesses the Company's nuclear programs on a continuing basis. As part of this assessment process, NOS performs audits to verify that applicable elements of the quality assurance and other regulatory required programs have been developed, documented and effectively implemented in accordance with specified requirements. In this section, the words assess, assessment, and their various word forms are used generically to indicate the act of monitoring the performance of the line organization for indications of decline.

NOS, along with the line organization management, monitors functional areas to determine if the required levels of performance are being achieved.

The functions of NOS are to assess line organization performance including the self-assessment and corrective action process. NOS performs these monitoring activities for nuclear safety related functions in operations, engineering, and maintenance.

NOS evaluations, including the results and recommended corrective actions, are reported to senior management.

17.3.3.3.1 Organization

On an exception basis, personnel in NOS may provide assistance to the line organization by participating in emergency preparedness activities, ad hoc committees or analyzing technical issues, if such assistance is deemed to be in the overall best interest of safety and is approved in advance by NOS management.

NOS teams may include peers from other Duke Energy Corporation plants and from the nuclear utility industry, as appropriate, to lend expertise to the assessment process. When subject matter experts from the line organizations are utilized to add specific technical expertise to a specific audit team, the subject matter experts will work under the direction of the audit team leader and not evaluate any documentation for which they had direct responsibility.

Selection of personnel is based on experience and training that establishes that their qualifications are commensurate with the complexity or special nature of the area being audited. The process for qualification of personnel to perform audits is established in procedures.

17.3.3.3.2 Internal Assessment Process

The internal assessment process includes gathering data, analyzing data, focusing on selected issues and identifying deficiencies to desired performance. Data is gathered using performance based techniques during:

a) Observations of work activities
b) Interviews
c) Reviews of documents to gather information (including the use of NRC, INPO, and other agency evaluations)
d) Audits, and
e) Analysis of data and reports (including adverse condition reports, etc.)

NOS personnel have access to records, procedures, and line organization personnel to gather data.

NOS conducts observations of specific activities, and processes on the basis of their impact and importance relative to safety. The schedule is flexible and dynamic to allow the overall assessment process to be changed depending on plant conditions, events, or issues raised by senior management. Assessment activities can be focused on areas most in need of improvement.

Audits are a specific independent assessment activity performed to verify that applicable elements of the quality assurance and other regulatory required programs have been developed, documented and effectively implemented in accordance with specified requirements. Independent Audit activities are selected with flexibility based on various factors. These factors include but are not limited to: importance to safety and reliability, monitoring of performance indicators, time since last audit, plant management perspective, outside agency audits, and problem areas identified from industry and Duke Energy Corporation experience.

Audits are scheduled per the following section.

17.3.3.3.3 Internal Audit Program

The Duke Energy Corporation QAP requires a comprehensive system of planned and periodic internal audits for all phases of station operations and supporting activities.

Periodic audits of activities or records of processes (e.g., welding, maintenance, development of design, record management, or system testing), to verify compliance and effectiveness of the implementation of the QAP are performed. NOS audits are performance based and scheduled based on plant performance and importance to safety but at a frequency not to exceed twenty-four months with extensions as allowed in Section 17.3.3.3.7, Audit Frequency Extensions.

The audit system is reviewed periodically and revised as necessary to assure coverage commensurate with current and planned activities. These audits encompass:

- The conformance of facility operation to provisions contained within the Technical Specifications and applicable license conditions.
- The performance, training and qualifications of the Nuclear Generation Department.
- The results of actions taken to correct deficiencies occurring in facility equipment, structures, or systems that affect nuclear safety; or method of operation that affect nuclear safety.
- The performance of activities required by the QAP to meet the criteria of Appendix B to 10 CFR 50 for activities performed by the Nuclear Generation Department and the interfacing organizations. Any other area of nuclear generation considered appropriate by responsible management.
- The Radiological Environmental Monitoring Program and the results thereof.
- The Offsite Dose Calculation Manual and implementing procedures.
- The Process Control Program and implementing procedures for processing and packaging of radioactive wastes.
- The acceptability of a representative sample of station procedures, including the effectiveness of the procedure review and revision program.
- Independent Spent Fuel Storage Installation Activities (reference 10 CFR Part 72).
- Packaging of Radioactive Materials for Off-Site Shipment (reference 10 CFR Part 71).

The scope of each audit is determined by the responsible Lead Auditor, under the direction of NOS management. The lead auditor is responsible for completion of audit checklists and directing the audit team in the performance of the audit. The audit is conducted in accordance with checklists; the scope may be expanded upon by the audit team during the audit, if needed. One or more persons comprise an audit team, one of whom is a qualified lead auditor.

17.3.3.3.3.1 Other Reviews Prescribed by the Code of Federal Regulations

Other reviews prescribed by the Code of Federal Regulations are scheduled and performed per the CFR. The audit frequency extension provisions of Section 17.3.3.3.7 do not apply.

NOS performs the following reviews under the internal audit program:

a. Emergency Preparedness (per 10 CFR 50.54(t))
b. Security (per 10 CFR 50.54(p) and 10 CFR Part 73)
c. Fitness for Duty and Fatigue Rule (per 10 CFR Part 26)

The periodic review of the radiation protection program content and implementation required by 10 CFR 20.1101c may be performed by either the line organization or NOS.

17.3.3.3.3.2 Independent Audit of Fire Protection Program

For sites implementing the fire protection program under provisions of 10 CFR 50.48(c) National Fire Protection Association Standard NFPA 805:

- An independent fire protection audit is performed at least once per 36 months using an outside (external to Duke Energy Corporation) qualified fire protection engineer meeting education and experience requirements for a Professional Member of the Society of Fire Protection Engineers (SFPE).

For the remaining sites, audits of the following functions are completed within a period of 24 months:

- The Facility Fire Protection programmatic controls including the implementing documents.
- The fire protection equipment and program implementation utilizing either a qualified offsite fire protection engineer or an outside independent fire protection consultant. An outside (external to Duke Energy Corporation) qualified fire protection engineer meeting education and experience requirements for a Professional Member of the SFPE shall be used at least every 36 months.
- The audit scope may be combined into a single audit performed on a 24 month frequency with the inclusion of an outside independent qualified fire protection engineer.

17.3.3.3.4 Results

Adverse conditions are reported in accordance with the applicable corrective action program procedure.

Independent audit results are communicated to line management to allow for timely action to address potential problems or recognize strengths and superior performance.

Follow-up is accomplished to assure that corrective action is taken as a result of the audit and that deficient areas are re-audited, when necessary, to verify implementation of adequate corrective actions.

17.3.3.3.5 Supplier Oversight

Supplier QA programs are evaluated and monitored by NOS-Vendor Quality, to assure that QA requirements are met. Supplier QA programs require a system of periodic and planned supplier and sub-supplier audits conducted by persons not directly involved in the activity being audited. Supplier audits are performed on a three year frequency with extensions as allowed in Section

17.3.3.3.7, Audit Frequency Extensions.

17.3.3.3.6 Independent Audit of QA Functions

As directed by the CNO, the executive for NOS initiates a program audit of the QA Functions performed by NOS. These functions include the internal audit program, the NOS portions of the supplier oversight program, and maintenance of this document (Quality Assurance Program Description). This program audit is performed within a period of two years with extensions as allowed in Section 17.3.3.3.7 Audit Frequency Extensions.

This audit team consists of qualified individuals, none of which is from the area audited.

The audit is performed with pre-approved checklists, instructions, or plans.

The audit team conducts a post-audit conference with the responsible management of the areas audited to discuss the audit results, including deficiencies. The audit team prepares checklists and the audit report. The report is sent to the executive for NOS.

The executive for NOS and/or responsible management of the area being audited determines the need for corrective action and re-evaluation. Necessary corrective action and re-evaluation are performed as required.

Pertinent correspondence and reports related to the audit are filed.

17.3.3.3.7 Audit Frequency Extensions

Except when the frequency is specified by regulation, the following criteria for extending audit intervals apply:

1) Schedules are based on the anniversary established for each audit.
2) A maximum extension not to exceed 25 percent of the audit interval may be allowed (e.g., audits on a two year frequency may not be extended beyond 30 months, audits on an annual frequency may not be extended beyond 15 months).
3) When an audit interval extension is used, the next audit for that particular audit area is scheduled from the original anniversary.
4) Provision 2) also applies to supplier audits and evaluations except that a total combined time interval for any three consecutive inspection or audit intervals should not exceed 3.25 times the specified inspection or audit interval.

17.3.4 ADMINISTRATIVE CONTROLS RELOCATED FROM TECHNICAL SPECIFICATIONS

Consistent with NRC Administrative Letter 95-06, certain administrative controls from the original station Technical Specifications have been relocated to the Quality Assurance Program. These relocated administrative controls included technical review, independent review, 10 CFR 50.59 review, record retention, and audit requirements. This section provides references to the sections of this document where the administrative controls have been integrated with QAP controls.

17.3.4.1 Technical Reviews

This content provided requirements for technical reviews of station modifications, procedures, tests, and experiments to assure adequacy of nuclear safety related SSCs and associated activities. Those reviews are embedded in the QAP and its committed Standards. See Sections 17.3.2.2, Design Control; 17.3.2.3, Design Verification; 17.3.2.8, Test Control; and 17.3.2.14, Document Control.

As identified by procedures, technical evaluations are performed by personnel qualified in the subject matter to determine the technical adequacy and accuracy of the proposed activity. If interdisciplinary evaluations are required to cover the technical scope of an activity, they will be performed. Technical review personnel are identified by the responsible manager or his designee for a specific activity when the review process begins.

17.3.4.2 10 CFR 50.59 Reviews

The review of station modifications, procedures, tests, and experiments against the requirements of 10 CFR 50.59 is to ensure that changes requiring prior NRC approval are submitted to and approved by the NRC prior to implementation. Provisions are included in Sections 17.3.2.3 Design Verification and 17.3.2.14 Document Control to amplify the need to complete these reviews.

The program for 10 CFR 50.59 reviews is in accordance with NEI 96-07, Revision 1, "Guidelines for 10 CFR 50.59 Evaluations" as endorsed by Regulatory Guide 1.187, November 2000.

This program includes provisions to ensure that individuals have appropriate qualifications prior to completing these reviews. A list of individuals qualified to perform 50.59 evaluations is maintained for each site.

While SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document, as these 50.69 LSS SSCs are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule. The exempted regulations do not include 10 CFR 50.59. Therefore, changes to SSCs considered LSS per 10 CFR 50.69 remain subject to the review requirements of 10 CFR 50.59.

17.3.4.3 Record Retention

The list of typical operational phase records is in Section 17.3.2.15, Records.

17.3.4.4 Audit Types and Frequencies

These are addressed in Section 17.3.3.3.3, Internal Audit Program.

17.3.4.5 On-Site Review Committee

This is addressed in Section 17.3.3.2, Independent Review.

17.3.4.6 Reportable Event Action

Procedures are established to assure events are reviewed and notifications and reports are made as required by Regulations including, but not limited to, 10 CFR Part 21, 10 CFR 50.72, and 10 CFR 50.73.

These procedures require for significant incidents occurring during operation where a safety limit is exceeded, or which could otherwise be related to the nuclear safety of the station, the Site executive is notified, the event is investigated, and a report prepared. These reports:

a) Contain a summary description of the circumstances and information relating to the subject incident.
b) Contain an evaluation of the effects of the incident.
c) Describe corrective action taken or recommended as a result of the incident.
d) Describe, analyze and evaluate any significant nuclear safety related implications of the incident.

SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document. These 50.69 LSS SSCs are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21, 10 CFR 50.72, 10 CFR 50.73 and other regulations as noted in the rule.

17.3.4.7 Independent Safety Engineering Group Functions

Independent Safety Engineering Group (ISEG) was addressed on a Site Specific basis for certain plants. See Site specific Attachments for additional requirements as follows:

- Attachment A, Brunswick Specific QAPD, Not Addressed.
- Attachment B, Harris Specific QAPD, Section B17.3.4.4, Independent Safety Engineering Group.
- Attachment C, Robinson Specific QAPD, Not Addressed
- Attachment D, Catawba, McGuire, and Oconee Specific QAPD, Section D17.3.4.7, Independent Safety Engineering Group

Attachment A, Brunswick Specific QAPD

Brunswick has received NRC approval to implement 10 CFR 50.69, Risk-informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors. SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of the QAPD as they are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule.

10CFR 50.69, provides alternative approaches for establishing the requirements for treatment of SSCs using a risk informed method of categorization according to safety significance. As part of implementing 10 CFR 50.69, engineering will establish a collection of program elements to monitor and / or maintain SSC critical attributes ensuring reasonable confidence in the continued capability and reliability of the design basis functions. These elements include, inspection and testing, corrective actions, feedback and process adjustments, performance monitoring, program documentation, and reporting, as applicable to meet 10CFR 50.69(d), (e), (f), and (g). DEC implements the requirements of the QAPD commensurate with the safety classification of the SSCs, as described in applicable licensing and design documents, and implementing procedures.

Information presented in this attachment is specific to Brunswick and was contained in the UFSAR prior to Amendment 41.

Where a section contains no descriptive information beyond that in the generic text in the body of the document, a statement is made to that effect and no content is included. See A17.3.1.2, Organization for example.

A17. BNP SPECIFIC QUALITY ASSURANCE

A17.1 BNP QA DURING DESIGN AND CONSTRUCTION

See Brunswick UFSAR Chapter 17 for historic information from the description of the QA Program for design and construction.

A17.2 OPERATIONAL QA

Deleted

(NOTE: In April 1995, NRC approved the reformatting of the description of the Brunswick QA Program to follow Standard Revision Plan Section 17.3, replacing the content of 17.2.)

A17.3 BNP QUALITY ASSURANCE PROGRAM (QAP) DESCRIPTION

INTRODUCTION

This content is not addressed in SRP Section 17.3; therefore, the Brunswick description of the QA Program did not include this section.

DEFINITIONS

There are no Brunswick specific definitions.

EXPLANATION OF "QUALITY ASSURANCE"

There is no Brunswick specific content.

QA STANDARDS AND GUIDES

Table A17-1 and A17-2 address QAP conformance to the referenced regulatory and program guidance in NUREG-0800 Section 17.3.

The content of Table A17-1 was transferred from Table 1-6 of the Brunswick UFSAR. Changes to the content of Table A17-1 are controlled in accordance with 10 CFR 50.54(a). Subsequent changes to the QAP are incorporated in this document as identified in Section 17.3.1.7.

Table A17-2 addresses additional Regulatory Guides that relate to implementation of the QAP but the implementation is site specific and controlled with the Brunswick UFSAR in accordance with 10 CFR 50.59.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards

Generic Exception:

Table A17-1 addresses the Brunswick Nuclear Plant (BNP) conformance of the Quality Assurance Program to certain NRC Regulatory Guides. In so doing, specific editions of industry standards are identified for compliance with exceptions and alternatives. Those identified standards include references to other industry standards for activities including, but not limited to; design, fabrication, inspection, and testing. Those included reference industry standards are considered to be guidance documents for details of how activities may be accomplished. The actual standard to be used in such cases is controlled by each station's current licensing and design bases.

Regulatory Guide 1.28, Quality Assurance Program Requirements (Design and Construction) (Safety Guide 28 June 1972) (Rev. 0)
ANSI Standard N45.2-1971, Quality Assurance Requirements for Nuclear Power Plants
This guide, and the standard it endorses, have been superseded for operations activities by Regulatory Guide 1.33 and ANSI N18.7-1976, which it endorses. The Operational Quality Assurance Program complies with Regulatory Guide 1.33 and ANSI N18.7-1976 as stipulated in Appendix A to that Program; therefore, Regulatory Guide 1.28 (Safety Guide 28) and ANSI N45.2-1971, which it endorses, are not considered necessary and are not included as part of the program.

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment (Safety Guide 30, Revision 0, August 1972)
ANSI Standard N45.2.4-1972 (IEEE-336-1971), Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations
BNP 1 and 2 comply with the provisions of Regulatory Guide 1.30, August 1972, as indicated below:

The installation, inspection, and testing of nuclear power plant instrumentation and electrical equipment at BNP will be in accordance with the applicable requirements of ANSI N45.2.4-1972 with the following exceptions:

1. Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in Brunswick commitment to Regulatory Guide 1.74.
2. Section 1.5 titled Reference Documents: Brunswick's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.
3. Section 2.5 titled Measuring and Test Equipment: Brunswick will implement the applicable portions of this Section as follows:

    The status of portable items of measuring and test equipment and reference standards shall be identified by use of status cards, computer schedules, or tags for the date recalibration is due. These items are in a calibration program which requires recalibration on a specified frequency or, in certain cases, prior to use.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment (Safety Guide 30, Revision 0, August 1972)

ANSI Standard N45.2.4-1972 (IEEE-336-1971), Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations

BNP 1 and 2 comply with the provisions of Regulatory Guide 1.30, August 1972, as indicated below:

Instrumentation and electrical equipment in the categories listed below shall be in a calibration program. This program provides, by the use of status cards, computer schedules, or tags, for the date that recalibration is due and indicates the status of calibration. The identity of person(s) performing the calibration is provided on the calibration documents.

a. Instruments installed as listed in the BNP Technical Specifications
b. Installed instrumentation used to verify BNP Technical Specification parameters
c. Installed safety-related instruments and electrical equipment that provide an active function during operation or during shutdown; i.e., not a device being designated safety-related solely because the instrument is an integral part of a pressure retaining boundary.

4. Section 7 titled Data Analysis and Evaluation states in part, "Procedures shall be established for processing inspection and test data and their analysis and evaluation." At BNP 1 and 2, (data processing procedures per se have not been developed; instead, test data are recorded, processed, and analyzed in accordance with procedures and instructions in appropriate functional areas; e.g., maintenance, startup.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation) (Safety Guide 33 November 1972)

ANSI Standard N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants

BNP 1 and 2 comply with the provisions of Regulatory Guide 1.33, November 1972, and the requirements and recommendations for administrative controls described in ANSI N18.7-1976 except as stated below:

1. Section 1 “Scope,” recommends that this standard applies to activities other than those associated with safety related equipment, activities, and procedures. SSCs categorized as Low Safety Significant in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule. As such, the scope of activities can be adjusted in station procedures as allowed by the rule. Procedures provide guidance for specific process changes as part of 10 CFR 50.69 implementation.
2. The requirements of Section 4.3 Independent Review Program are replaced by Section 17.3.3.2, Independent Review. This exception uses NRC Safety Evaluation dated January 13, 2005 to Nuclear Management Company (ADAMS ML050210276).
3. Deleted - see exception 1.
4. Section 4.5 - Written audit reports are not formally reviewed as part of the Independent Review function.
5. Section 4.5 - The CNO will assure that an independent assessment of the overall Nuclear Oversight Program is conducted at least once every 24 months. See Section 17.3.3.3.6, Independent Audit of QA Functions.
6. Section 4.5, Audit Program - ANSI N18.7-1976/ANS-3.2, Section 4.5 is implemented with the following clarification: The audits of selected aspects of operational phase activities as

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

identified in Section 17.3.3.3.3, Internal Audit Program, are scheduled based on plant performance and importance to safety but at a frequency not to exceed twenty-four months with extensions as allowed in Section 17.3.3.3.7, Audit Frequency Extensions.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation) (Safety Guide 33 November 1972)
ANSI Standard N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants
BNP 1 and 2 comply with the provisions of Regulatory Guide 1.33, November 1972, and the requirements and recommendations for administrative controls described in ANSI N18.7-1976 except as stated below:

7. Section 5.2.2 titled Procedure Adherence: Temporary changes to approved procedures and proposed tests or experiments may be made provided; a) the intent of the original procedure, proposed test or experiment is not altered; b) the change is approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator License on the unit affected; and c) the change is documented and, if appropriate, reviewed and approved for incorporation in the next revision of the procedure within 14 days of implementation of the temporary change.
8. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, November 1972, shall be established, implemented, and maintained as specified in the BNP 1 and 2 BNP Technical Specifications.
9. Section 5.2.7 - BNP will comply with requirements of the first sentence of the second paragraph and provides the following clarification:
   a. "Documented Instructions" is defined as any credible information (e.g., vendor manuals, vendor recommendations, engineering direction, etc.) Used for work planning/execution which is reviewed and approved prior to use in accordance with approved procedures.
10. Section 5.2.13, titled Procurement Document Control: When purchasing commercial grade calibration services from certain accredited calibration laboratories, the procurement documents are not required to impose a quality assurance program consistent with ANSI N45.2-1971. Alternate requirements described in Tables 17-1 and A17-1 for Regulatory Guide 1.123 may be implemented in lieu of imposing a quality assurance program consistent with ANSI N45.2-1971. When purchasing nuclear safety related material, equipment and services, the supplier is required to the meet applicable criteria of 10 CFR 50, Appendix B and 10 CFR 21– with the exception that SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document. These 50.69 LSS SSCs are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule. Procedures provide guidance for specific process changes as part of 10 CFR 50.69 implementation.
11. Section 5.2.15 titled <u>Review, Approval and Control of Procedures,</u> states that, "Plant procedures shall be reviewed by an individual knowledgeable in the area affected by the procedure no less frequently than every two years to determine if changes are necessary. A revision to a procedure constitutes a procedure review." In lieu of this commitment, Duke Energy addresses programmatic controls in Section 17.3.2.14 to continually identify procedure revisions which may be needed to ensure that procedures are appropriate for the circumstance and are maintained current.
12. Section 5.2.17, second to the last sentence in the last paragraph, "Deviations, their cause, and any…," to be consistent with Section 5.2.11 and 10CFR 50, Appendix B, the cause of the deviation will be determined for only significant conditions adverse to safety.
13. Section 5.3.5(4) last sentence - BNP interprets the review requirements for "Supporting Maintenance Documents" which have not been incorporated in a procedure, be performed

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

in an equivalent manner as described in approved procedures.

14. Section 5.3.9.1, titled Emergency Procedure Format and Content: Emergency procedures shall be in the format as committed to in NUREG-0737, TMI Action Plan.
15. ANSI N18.7-1976, Section 5.2.16. See Section A17.3.2.9 for clarification.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation) (Safety Guide 33 November 1972)
ANSI Standard N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants
BNP 1 and 2 comply with the provisions of Regulatory Guide 1.33, November 1972, and the requirements and recommendations for administrative controls described in ANSI N18.7-1976 except as stated below:
16. Section 5.3.10, first paragraph - The requirement "Test and inspection results shall be documented...," will be implemented as follows: As an alternative to the records required for inspections outlined in Section 5.3.10, BNP shall provide the following as the method to document results of inspections. The results of inspections will be documented in appropriate records and those records shall, as a minimum, identify a) through f) below: a) Item inspected b) Date of inspection c) Inspector d) Type of observation e) Results or acceptability f) Reference to information on action taken in connection with non-conformances.

Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants (March 1973)
ANSI Standard N45.2.1-1973, Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants
Those areas of the QA Program applicable to onsite cleaning of materials and components, cleanliness control, and pre-operation cleaning and layup of BNP 1 and 2 fluid systems, will be in accordance with ANSI N45.2.1-1973, with the following exceptions:
1. At BNP 1 and 2, a classification system similar to ANSI N45.2.1-1973 has been developed and is fully implemented for cleaning of fluid systems. 2. Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in BNP's commitment to Regulatory Guide 1.74. 3. Section 1.5 titled Referenced Documents: BNP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging Shipping Receiving Storage and Handling of Items for Water-Cooled Nuclear Power Plants (March 1973)
ANSI Standard N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants
Packaging, shipping, receiving, storage, and handling of BNP items are in accordance with applicable requirements of ANSI N45.2.2-1972 with the following specific exceptions:
1. Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in BNP's commitment to Regulatory Guide 1.74.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

2. Section 1.5 titled Referenced Documents: BNP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging Shipping Receiving Storage and Handling of Items for Water-Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants

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Packaging, shipping, receiving, storage, and handling of BNP items are in accordance with applicable requirements of ANSI N45.2.2-1972 with the following specific exceptions:

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3. Section 2.7 titled Classification of Items and Section 6.1.2 titled Levels of Storage:
   a. Special electronic equipment and instrumentation received as assembled panels will be stored as recommended by the manufacturer and/or based on engineering evaluation to prevent damage, deterioration, or contamination, but not necessarily in a Level A storage area.
   b. Chemicals used at BNP 1 and 2 are stored at the point of use and/or in warehouse areas that satisfy the requirement of Level B storage. These storage areas have been evaluated and determined to be adequate for the limitations established by the manufacturer.
   c. Special nuclear materials are stored in areas specifically designed for such storage.
4. Section 6.4.2, Care of Items: The following alternates are provided for indicated subparts:
   a. Space heaters in electrical equipment shall be energized unless a documented engineering evaluation determines that such space heaters are not required.
   b. Rotating electrical equipment, commensurate to safety or reliability, shall be given insulation resistance tests on a schedule basis, unless a documented evaluation determines that such tests are not required.
   c. Rotating equipment, commensurate to safety or reliability, shall be evaluated for shaft rotation requirements. The degree of turn shall be established so that the parts receive a coating of lubrication where applicable, and so that the shaft does not come to rest in a previous position. (90 deg. and 450 deg. rotations are examples.)
   d. Other maintenance requirements specified by the manufacturer’s instructions shall be evaluated to determine applicability during storage of the item.
5. Section 7.3.4 - BNP intends to comply with the requirements of this Section with the following clarification: Test loads equal to or greater than the original crane rating shall not pass over locations where special nuclear material is stored or where reactor system components or high cost equipment are located.
6. Section 6.2.4, Storage of Food and Associated Items: The sentence is replaced with the following: "The use or storage of food, drinks, and salt tablet dispensers in any storage area shall be controlled and shall be limited to designated areas where such use or storage is not deleterious to stored items."

Regulatory Guide 1.39, Housekeeping Requirements for Water-Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.3-1973, Housekeeping, During the Construction Phase of Nuclear Power Plants

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The applicable operational phase requirements of N45.2.3-1973 are followed at BNP within the context of the established QA Program with the following specific exception -- the zone designations of Section 2.1 of N45.2.3 and the requirements associated with each zone are

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

considered impractical for implementation, as stated, at BNP during the operations phase. Instead, procedures or instruction for housekeeping activities, which include the applicable requirements outlined in Section 2.1 of N45.2.3, and which take into account radiation control considerations, security considerations, and cleanliness requirements, are developed on a case by case basis for work to be performed.

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel (September 1980)
ANSI Standard N45.2.6-1978, Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants"
BNP 1 and 2 comply with NRC Regulatory Guide 1.58, September 1980, which endorses ANSI N45.2.6-1978, with the following exceptions:

1. Section 1.2 titled Applicability: BNP elects not to apply the requirements of this guide to those personnel who are involved in the daily operations of surveillance, maintenance, and certain technical and support services whose qualifications are controlled by the BNP Technical Specifications or are controlled by other QA Program commitment requirements. Only personnel in the following listed categories will be required to meet ANSI N45.2.6-1978 requirements:
   a. Nondestructive examination (NDE) personnel
   b. QC inspection personnel
   c. Receipt Inspection personnel
2. The fourth paragraph of Section 1.2 requires that the Standard be imposed on personnel other than BNP employees. The applicability of the Standard to suppliers and contractors will be documented and applied, as appropriate, in the procurement documents for such suppliers and contractors or in interface agreements for Duke Energy non-nuclear organizations providing services identified in Section 17.3.1.2.3.
3. Section 1.4 titled Definitions: Definitions in this Standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in BNP's commitment to Regulatory Guide 1.74.
4. Section 2.5 titled Physical: BNP will implement the requirements of this Section with the stipulation that, where no special physical characteristics are required, none will be specified. The converse is also true: if no special physical requirements are stipulated by BNP, none are considered necessary. BNP employees receive an initial physical examination to assure satisfactory physical condition; however, only the following listed personnel will receive an annual examination:
   a. NDE personnel
   b. QC inspection personnel
   c. Receipt inspection personnel

   This annual examination shall consist of the near visual acuity using the standard Jaeger's type chart or equivalent test.

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel (September 1980)
ANSI Standard N45.2.6-1978, Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants"
BNP 1 and 2 comply with NRC Regulatory Guide 1.58, September 1980, which endorses ANSI N45.2.6-1978, with the following exceptions:

5. Section 3 titled Qualifications: Only personnel performing NDE (such as LP, MT, UT, and RT) are required to be grouped in levels of capability and certified as such. QC inspection personnel will be certified for inspection, review, and evaluation of inspection data, and

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

reporting of inspection and test results.

6. Section 3.5 titled Education & Experience Recommendations: BNP will certify individual inspectors through training and experience to requirements appropriate to the specific assignment; however, except for NDE, personnel are not required to be classified by levels of capability. Inspection personnel may be qualified based on pre-established experience, education, on-the-job training, written examinations and proficiency tests associated with the specific activity. Proficiency tests are given to personnel performing independent QC inspections and documented acceptance criteria are developed to determine if individuals are properly trained and qualified. Certificates of qualification delineate the functions personnel are qualified to perform. Qualification records are maintained and performance evaluations conducted at least once every three years. If organizations elect to utilize qualifications by levels for non-NDE inspections, Level I inspectors receive a minimum of 4 months experience as Level I before being certified as Level II, in lieu of one year experience recommended by ANSI N45.2.6 Section 3.5.2(1). Organizations identify in their procedures if they qualify their inspectors by Level or by task qualifications. Inspectors are only assigned functions for which they have been qualified.

Regulatory Guide 1.64, Quality Assurance Requirements for the Design of Nuclear Power Plants (October 1973)
ANSI Standard N45.2.11-1974, Quality Assurance Requirements for the Design of Nuclear Power Plants
Those areas of the QA Program for BNP 1 and 2 applicable to design or modification of the plant are in accordance with the applicable guidance of ANSI N45.2.11-1974, with the following exception:
1. Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in the BNP commitment to Regulatory Guide 1.74.

Regulatory Guide 1.74, Quality Assurance Terms and Definitions (February 1974)
ANSI Standard N45.2.1.0-1973, Quality Assurance Terms and Definitions
Comply with the provisions of Regulatory Guide 1.74, February, 1974.

Regulatory Guide 1.88, Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records (August 1974)
ANSI Standard N45.2.9-1974, Collection, Storage, and Maintenance of QA Records
The requirements for collection, storage, and maintenance of QA records at BNP will be in accordance with ANSI N45.2.9-1974 and 17.3.2.15, with the following specific exceptions:

See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.

1. The document control facility at the BNP shall comply with the requirement of Regulatory Guide 1.88, October, 1976, Regulatory Position C.2 in that the facility has been specifically designed to protect the contents from fire in accordance with NFPA 232-1975, with the following exceptions/alternatives/comments:
   a. Records are classified as Class 1 - Vital Records in accordance with NFPA 232-1975, Chapter 5, Section 5222; however, the records that meet this classification include those determined to be QA records as defined in ANSI N45.2.9-1974, Section 1.4.
   b. The facility is constructed in accordance with NFPA 232-1975 requirements for a fire-resistive file room as defined in NFPA 232-1975, Chapter 3. The walls were designed

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

and constructed equivalent to a four-hour barrier. The doors are four-hour rated vault doors. Penetrations for electrical service and ventilation are sealed to a rating of 3 hours to protect the vault from a fire originating outside the vault.

c. Due to the construction of the facility and other safety measures described herein, the statement in NFPA 232-1975, Chapter 3, Section 3022(d), "Class 1 . . . records should not be subjected to these possibilities of destruction by fire" is deemed to be inappropriate.
d. The facility is protected by a Halon fire extinguishing system, automatic door closures, and fire detection system.
e. The floor of the file room is six inches higher than the floor areas outside the file room.
f. The walls are reinforced concrete, ten inches thick.
g. The exterior walls are totally enclosed and insulated from the outside environment and elements.
h. The facility is constructed independently from the building.
i. NFPA 232-1975, Chapter 3, Sections 332 and 333 describe methods for heating and ventilation.
   The facility will have penetrations in the wall for the purposes of heating and ventilation. The facility is equipped with a Heating, Ventilating and Air Conditioning system external to the file room with automatic closing dampers.
j. 120 VAC wall outlets are provided in the file room for emergency lighting and janitorial needs. These outlets may be de-energized from a disconnect box installed on the outer wall of the records storage facility. The lighting may be disconnected outside the room and is equipped with a red pilot light.
k. BNP QA records not stored in the facility described above may be retained at off-site locations which meet the requirements (with approved exceptions as necessary) of Section 5.6, ANSI 45.2.9-1974.

2. Section 1.4, Definitions: The phrase "when the document has been completed" is clarified to mean when the document has received the final review performed by the organizational element responsible for generating or collecting the records. In the case of a record package made up of several individual documents, the package will be considered to be the document for the purpose of determining when the record is complete.
3. Section 3.2.1, Generation of Quality Assurance Records: The phrase "completely filled out" is clarified to mean that sufficient information is recorded to fulfill the intended purpose of the record.

Regulatory Guide 1.88, Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records (August 1974)
ANSI Standard N45.2.9-1974, Collection, Storage, and Maintenance of QA Records
The requirements for collection, storage, and maintenance of QA records at BNP will be in accordance with ANSI N45.2.9-1974 and 17.3.2.15, with the following specific exceptions:

4. Section 4.2, Timeliness: BNP's contractual agreement with its contractors and suppliers will constitute fulfillment of the requirements of this paragraph.
5. Section 5.4, Preservation: The following clarification is substituted for the current subsection 5.4.2: "Records shall not be stored loosely. They shall be secured for storage in file cabinets or on shelving in containers." The following clarification is substituted for the current subsection 5.4.3: "Appropriate provisions shall be made for special processed records (such as radiographs, photographs, negatives, microfilm and magnetic media) to prevent or minimize damage for excessive light, stacking, electromagnetic fields, temperature and humidity, etc. Manufacturer's recommendations will be considered as appropriate."
6. Section 5.6, Facility: This paragraph provides no distinction between temporary and permanent facilities. To cover temporary storage, the following clarification is added: "Complete records may be stored in one-hour fire rated file cabinets until transmitted for

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

permanent storage. In general, records shall not be maintained in temporary storage by the generating organization for more than 90 days after completion. Any exceptions to this requirement must be justified, evaluated and approved by the records management organization and documented. A list of exceptions shall be maintained and available for NRC review. Exceptions may include records needed on a continuing basis for an extended period of time at the location of the work group responsible for generating the records and records which are cumulative in nature and could best be turned over for storage for a designated period of time."

The records management organization will store records in one-hour rated file cabinets while the records are being processed for permanent storage.

7. See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.

Regulatory Guide 1.94, Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants (Rev. 1, April 1976)
ANSI Standard N45.2.5-1974, Supplementary Quality Assurance Requirements for Installation Inspections and Testing of Structural Steel During the Contract Phase of Nuclear Power Plants
Regulatory Guide 1.94, Revision 1, April 1976 endorses ANSI N45.2.5-1974. BNP 1 and 2 do not commit to Regulatory Guide 1.94 but do endorse parts of ANSI N45.2.5-1974 as described below.
The original specification requirements, applicable guidance contained in ANSI N45.2.5-1974, or acceptable alternatives based on an engineering evaluation will be utilized in the event future structural work is to be performed which falls under the established requirements of the BNP QA Program.

Regulatory Guide 1.116, QA Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems (June 1976)
ANSI Standard N45.2.8-1975, Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems for the Construction Phase of Nuclear Power Plants
Regulatory Guide 1.116, June 1976, endorses ANSI N45.2.8-1975. BNP 1 and 2 does not commit to Regulatory Guide 1.116 but does endorse parts of ANSI N45.2.8-1975 as described below.

Within the context of the established QA Program, the applicable guidance contained in ANSI N45.2.8-1975 will be utilized in relation to mechanical maintenance or modification with the following exceptions:

1. Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in BNP's commitment to Regulatory Guide 1.74.
2. Section 1.5 titled Referenced Documents: BNP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.
3. Section 2.8 titled Measuring and Test Equipment: BNP will implement the applicable portions of this Section as follows:
    a. The status of portable items of measuring and test equipment and reference standards shall be identified by use of status cards, computer schedules, or tags for the date recalibration is due. These items are in a calibration program which requires recalibration on a specified frequency or, in certain cases, prior to use.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

b. Instrumentation and electrical equipment in the categories listed below shall be in a calibration program. This program provides, by the use of status cards, computer schedules, or tags, for the date that recalibration is due and indicates the status of calibration. The identity of person(s) performing the calibration is provided on the calibration documents.

   1) Instruments installed as listed in the BNP Technical Specifications

   2) Installed instrumentation used to verify BNP Technical Specification parameters

   3) Installed safety-related instruments and electrical equipment that provide an active function during operation or during shutdown; i.e., instead of being designated safety-related solely because the instrument is an integral part of a pressure retaining boundary,

4. Section 6 titled Data Analysis and Evaluation states in part, "Procedures shall be established for processing inspection and test data and their analysis and evaluation."

   At BNP 1 and 2, data processing procedures per se have not been developed; instead, test data are recorded, processed, and analyzed in accordance with procedures and instructions in appropriate functional areas; e.g., maintenance, startup.

Regulatory Guide 1.123, "Quality Assurance Requirement for Control or Procurement of Items and Services for Nuclear Power Plants"
ANSI Standard N45.2.13, "Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants" (Draft 2, Rev. 4, April 1974)

Regulatory Guide 1.123, "Quality Assurance Requirement for Control or Procurement of Items and Services for Nuclear Power Plants"
ANSI Standard N45.2.13, "Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants" (Draft 2, Rev. 4, April 1974)
BNP does not commit to Regulatory Guide 1.123; however, the applicable guidance contained in ANSI N45.2.13 (Draft 2, Revision 4, April 1974) and ANSI N18.7-1976, will be utilized in relation to procurement of items and services performed under the established requirements of the QA Program.
See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and Services including, purchasing commercial-grade calibration services from calibration laboratories.

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants (January 1979)
ANSI Standard N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants
BNP will follow the requirements and recommendations of Regulatory Guide 1.144 and ANSI Standard N45,2.12, with the following clarifications:

1. BNP will follow the requirements and recommendations of Regulatory Guide 1.144, paragraphs C.1, C.2, C.3.a.2, C.3.b, and C.4. BNP's position on paragraph C.3.a.1 is as follows:

   Audits of operational phase activities, as outlined in Section 17.3.3.3 shall be performed at the frequencies stated in exception 5 for RG 1.33 in Table A17-1.

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.

2. (Deleted)
3. BNP will comply with the last paragraph of Section 4.4 of ANSI N45.2.12 concerning issuing audit reports, with the following clarification: "Audit reports shall be issued within thirty working days after the last day of the audit. The last day of the audit shall be considered to be the day of the post-audit conference. If a post-audit conference is not held because it was deemed unnecessary, the last day of the audit shall be considered to be the date the post-audit conference was deemed unnecessary as documented in the audit report."
4. ANSI N45.2.12 Section 4.3.1, Preaudit Conference: BNP will comply with the requirement of this paragraph by inserting the word "Normally" at the beginning of the first sentence. This clarification is required because, in the case of certain unannounced audits or audits of a particular operation or work activity, a preaudit conference might interfere with the spontaneity of the operation or activity being audited. In other cases, persons who should be present at a preaudit conference may not always be available. Such lack of availability should not be an impediment to beginning an audit. Even in the above examples, which are not intended to be all inclusive, the material set forth in Section 4.3.1 will normally be covered during the course of the audit.

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants (January 1979)

ANSI Standard N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants

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BNP will follow the requirements and recommendations of Regulatory Guide 1.144 and ANSI Standard N45,2.12, with the following clarifications:

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5. ANSI N45.2.12 Section 4.3.3, Post Audit Conference: BNP will substitute and comply with the following paragraphs:
   For all external audits, a post audit conference shall be held with management of the audited organization to present audit findings and clarify misunderstandings. Where no adverse findings exist, this conference may be waived by management of the audited organization. Such waiver shall be documented in the audit report. For all internal audits, unless unusual operating or maintenance conditions preclude attendance by appropriate management, an audit exit shall be held with management of the audited organization. If there are no adverse findings, management of the audited organization may waive the audit exit. Such waiver shall be documented in the audit report.
6. ANSI N45.2.12 Section 4.4, Reporting:
   a. This paragraph requires that the audit report be signed by the audit team leader which is not always the most expeditious route for the audit report to be issued as soon as possible. BNP will comply with Section 4.4 as clarified to read:
      An audit report shall be signed by the audit team leader or the leader's supervisor in the absence of the audit team leader. In cases where the audit report is not signed by the audit team leader due to the leader's absence, the record copy of the report must be signed by the audit team leader upon return. The report shall not require the audit team leader's review/concurrence/signature if the audit team leader is no longer employed by BNP at the time audit report is issued. The audit report shall provide:
   b. BNP will comply with Subsection 4.4.3 clarified to read: "Supervisory level personnel with whom significant discussions were held during the course of preaudit (where conducted), audit, and post audit (where conducted) activities.
   c. Subsection 4.4.6 requires audit reports to include recommendations for corrective

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

actions. BNP may choose not to comply with this requirement. Instead, BNP audit reports are required to document findings.

Regulatory Guide 1.146, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants (Rev. 0 August 1980)
ANSI Standard N45.2.23-1978, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants
BNP 1 and 2 comply with NRC Regulatory Guide 1.146, Revision 0, which endorses ANSI N45.2.23-1978, with the following exceptions:

1. Section 1.4 titled Definitions: Definitions in this Standard which are not included in ANSI N45.2.10 will be used; "Audit" which is included in ANSI N45.2.10 will be used as clarified in BNP's commitment to Regulatory Guide 1.74.
2. Section 2.2 titled Qualification of Auditors: Subsection 2.2.1 references an ANSI B45.2 which will be assumed to be N45.2. BNP will comply with an alternate subsection 2.2.1 which reads:
   Orientation to provide a working knowledge and understanding of the BNP Quality Assurance Program, including the Regulatory Guides and ANSI standards included in the Program, and BNP procedures for performing audits and reporting results.

Regulatory Guide 1.146, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants (Rev. 0 August 1980)
ANSI Standard N45.2.23-1978, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants
BNP 1 and 2 comply with NRC Regulatory Guide 1.146, Revision 0, which endorses ANSI N45.2.23-1978, with the following exceptions:

3. (Deleted)
4. Section 4.1 titled Organizational Responsibility: BNP will comply with this Section with the substitution of the following sentence in place of the last sentence in the Section:

   Management or the Audit Team Leader shall, prior to commencing the audit, assign personnel who collectively have experience or training commensurate with the scope, complexity, or special nature of the activities to be audited.
5. Section 5.3 titled Updating of Lead Auditors' Records: BNP will substitute the following sentence for this Section:

   Records for each Lead Auditor shall be maintained and updated during the annual management assessment as defined in Section 3.2 (as clarified).
6. Section 5.4 titled Record Retention: BNP will substitute the following sentence for this Section:
   Qualification records shall be retained as required by the BNP Quality Assurance Program.
7. ANSI N45.2.23-1978, Section 2.3.4 titled Audit Participation: BNP will substitute the following for this Section:

   Prospective Lead Auditors shall demonstrate the ability to effectively implement the audit process and effectively lead an audit team. This process is described in written procedures which provide for evaluation and documentation of the results of this demonstration. In addition, the prospective Lead Auditor shall have participated in at least two Nuclear Oversight audits within the year preceding the individual's effective date of qualification. Upon successful demonstration of the ability to effectively implement the audit process and

Table A17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

effectively lead audits, and having met the other provisions of Section 2.3 of ANSI/ASME N45.2.23-1978, the individual may be certified as being qualified to lead audits.

Table A17-2. Site Specific Response to Regulatory Guides and Industry Standards

Table A17-2 identifies additional Regulatory Guides addressing subjects related to implementation of the QAP but the implementation is site specific and controlled with the UFSAR in accordance with 10 CFR 50.59.

Regulatory Guide 1.8, Personnel Selection and Training

Personnel selection and training is site specific.

Brunswick addresses conformance with Regulatory Guide 1.8 (SAFETY GUIDE 8, MARCH 1971) in UFSAR Chapter 1 Table 1-6.

Each member of the facility staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions, except for:

a. The manager of the radiation control function, who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975;
b. The shift technical advisor, who shall have a bachelor's degree or equivalent in a scientific or engineering discipline with specific training in plant design and response and analysis of the plant during transients and accidents; and
c. The operations manager, who shall meet or exceed the above requirements except that Technical Specification 5.2.2.f shall specify the requirements regarding holding an SRO license.

Regulatory Guide 1.26, Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants

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Quality group classifications and standards trace to the original design and construction of the nuclear power plant and therefore are site specific.

Brunswick does not address Regulatory Guide 1.26 in UFSAR Chapter 1 Table 1-6. Quality group classifications are addressed in UFSAR Chapter 3.

Regulatory Guide 1.29, Seismic Design Classification

Seismic design classification trace to the original design and construction of the nuclear power plant and therefore is site specific.

Brunswick addresses conformance with Regulatory Guide 1.29 in UFSAR Chapter 1 Table 1-6.

Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel

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Nonmetallic thermal insulation for austenitic stainless steel trace to the original design and construction of the nuclear power plant and therefore is site specific.

Brunswick does not address conformance with Regulatory Guide 1.36 in UFSAR Chapter 1 Table 1-6. Thermal insulation for austenitic stainless steel is addressed in UFSAR Section 5.2.

Regulatory Guide 1.54, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants

Quality assurance requirements for protective coatings applied to water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Brunswick addresses conformance with Regulatory Guide 1.54 in UFSAR Chapter 1 Table 1-6.

Table A17-2. Site Specific Response to Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.143, Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants

Design guidance for radioactive waste management systems, structures, and components installed in light-water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Brunswick does not address conformance with Regulatory Guide 1.143 in UFSAR Chapter 1 Table 1-6. Design guidance for radioactive waste management systems, structures, and components is addressed in UFSAR Chapter 11.

Regulatory Guide 1.155, Station Blackout

Addressing Station Blackout is site specific.

Brunswick addresses conformance with Regulatory Guide 1.155 in UFSAR Chapter 1 Table 1-6.

Regulatory Guide 4.15, Quality Assurance for Radiological Monitoring Programs (Normal Operations) – Effluent Streams and the Environment

Quality assurance for radiological monitoring program (normal operations) – effluent streams and the environment is site specific.

Brunswick does not address conformance to Regulatory Guide 4.15 in UFSAR Chapter 1 Table 1-6. The radiological monitoring program is addressed in UFSAR Chapter 11.

A17.3.1 MANAGEMENT

A17.3.1.1 Methodology

There are no Brunswick specific amplifications for this section.

A17.3.1.2 Organization

There are no Brunswick specific amplifications for this section.

A17.3.1.3 Responsibility

There are no Brunswick specific amplifications for this section.

A17.3.1.4 Authority

The program and procedures require that the authority and duties of persons and organizations performing activities affecting quality functions be clearly established and delineated in writing and that these individuals and organizations have sufficient authority and organizational freedom to:

1. Identify quality, nuclear safety, and performance problems.
2. Order unsatisfactory work to be stopped and control further processing, delivery, or installation of nonconforming material.
3. Initiate, recommend, or provide solutions for conditions adverse to quality.
4. Verify implementation of solutions.

A17.3.1.5 Personnel Training and Qualification

There are no Brunswick specific amplifications for this section.

A17.3.1.6 Corrective Action

The program requires that an evaluation of adverse conditions such as conditions adverse to quality, nonconformances, failures, malfunctions, deficiencies, deviations, and defective material and equipment is conducted to determine need for corrective action.

Conditions adverse to quality are identified through inspections, assessments, tests, checks, and review of documents.

The program requires corrective action to be initiated to preclude recurrence of significant conditions adverse to quality.

Procedures require follow-up reviews, verifications, inspections, etc., to be conducted to verify proper implementation of corrective action and to close out the corrective action documentation.

The program outlines the methodology for resolution of disputes involving quality and nuclear safety issues arising from a difference of opinion between identifying personnel and other groups.

Significant conditions adverse to quality are reported to appropriate management for review and evaluation.

Periodic review and evaluation of adverse trends are performed by management.

A17.3.1.7 Regulatory Commitments

Written procedures shall be established, implemented, and maintained to ensure implementation of the Process Control Program.

A17.3.2 PERFORMANCE/VERIFICATION

A17.3.2.1 Methodology

There are no Brunswick specific amplifications for this section.

A17.3.2.2 Design Control

There are no Brunswick specific amplifications for this section.

A17.3.2.3 Design Verification

There are no Brunswick specific amplifications for this section.

A17.3.2.4 Procurement Control

Potential contractors and suppliers are evaluated prior to award of a procurement contract when needed to assure the contractor's or supplier's capability to comply with applicable technical and quality requirements.

Procurement documents, such as purchase specifications, contain or reference the following:

1. Technical, administrative, regulatory, and reporting requirements, including material and component identification requirements, drawings, specifications, codes and industrial standards, test and inspection requirements, and special process instructions.
2. Identification of the documentation to be prepared, maintained, or submitted (as applicable) to BNP for review and approval. These documents may include, as necessary, inspection and test records, qualification records, or code required documentation.
3. Identification of those records to be retained, controlled, and maintained by the supplier, and those delivered to the purchaser prior to use or installation of the hardware.

Procurement documents require suppliers to operate in accordance with QA programs which are compatible with the applicable requirements of the QA Program and procedures where their services are utilized in support of plant activities.

A17.3.2.5 Procurement Verification

There are no Brunswick specific amplifications for this section.

A17.3.2.6 Identification and Control of Items

Procedures require that materials, parts, and components be identified and controlled to prevent the use of incorrect or defective items. These procedures also require that identification of items be maintained either on the item in a manner that does not affect the function or quality of the item, or on records traceable to the item.

Procedures implementing these requirements provide for the following:

1. Verification that items received at the plant are properly identified and can be traced to the appropriate documentation, such as drawings, specifications, purchase orders, manufacturing and inspection documents, nonconformance reports, or material test reports.
2. Verification of item identification consistent with the BNP inventory control system and traceable to documentation which identifies the proper uses or applications of the item.

A17.3.2.7 Handling, Storage, and Shipping

Provisions are established to control the shelf life and storage of chemicals, reagents, lubricants, and other consumable materials.

A17.3.2.8 Test Control

Test procedures incorporate or reference the following, as required:

1. Instructions and prerequisites for performing the test,
2. Use of proper test equipment,
3. Mandatory inspection hold points,
4. Acceptance criteria

Test results are documented, evaluated, and their acceptability determined by a qualified, responsible individual or group.

When the acceptance criteria are not met, affected areas are to be retested or evaluated, as appropriate.

A17.3.2.9 Measuring and Test Equipment Control

Portable measuring and test equipment are calibrated by standards at least four times as accurate as the portable measuring and test equipment, unless limited by the state of the art.

Special tools such as torque wrenches, calipers, and micrometers are calibrated to be at least as accurate as the application(s) for which it is used, using standards which are at least as accurate as the special tool being calibrated.

Installed measuring and test instruments are calibrated by instruments at least as accurate as the installed, unless limited by the state of the art.

Reference and transfer standards are traceable to nationally recognized standards; or where national standards do not exist, provisions are established to document the basis for the calibration.

A17.3.2.10 Inspection Test and Operating Status

These procedures include the application, removal, and verification of inspection and welding stamps, or other status indicators as appropriate.

Altering the sequence of required tests, inspections, and safety-related operations can only be accomplished by methods outlined in procedures.

A17.3.2.11 Special Process Control

There are no Brunswick specific amplifications for this section.

A17.3.2.12 Inspection

There are no Brunswick specific amplifications for this section.

A17.3.2.13 Corrective Action

The primary goal of the BNP corrective action program is to improve overall plant operations and performance by identifying and correcting root causes of equipment and human performance problems.

Procedures define requirements for a corrective action program that charges personnel working at or supporting the nuclear plants with the responsibility to identify adverse conditions (including conditions adverse to quality).

Procedures include requirements for verification of the acceptability of the rework/repair of items by re-inspection and/or testing in accordance with the original inspection or test requirements or by an accepted alternative inspection and testing method.

Conditions that require rework/repairs are identified through the use of maintenance work request forms.

A17.3.2.14 Control of Documents

Changes to documents are reviewed and approved by the same organization that performed the original review and approval or by other designated qualified responsible organizations.

A17.3.2.15 Records

The structure in which single copy records are maintained is designed to prevent destruction, deterioration or theft. This structure ensures protection against destruction by fire, flooding, theft and deterioration by the environmental conditions of temperature and humidity.

A17.3.2.16 Record Retention

A list of typical operational phase QA Records is included in 17.3.2.15.

A17.3.3 ASSESSMENT

A17.3.3.1 Methodology

There are no Brunswick specific amplifications for this section.

A17.3.3.2 Independent Review

There are no Brunswick specific amplifications for this section.

A17.3.3.3 Independent Assessment

There are no Brunswick specific amplifications for this section.

A17.3.3.3.1 Organization

There are no Brunswick specific amplifications for this section.

A17.3.3.3.2 Internal Assessment Process

There are no Brunswick specific amplifications for this section.

A17.3.3.3.3 Internal Audit Program

A17.3.3.3.3.1 Other Reviews Prescribed by the Code of Federal Regulations

There are no Brunswick specific amplifications for this section.

A17.3.3.3.3.2 Independent Audit of Fire Protection Program

There are no Brunswick specific amplifications for this section.

A17.3.3.3.4 Results

There are no Brunswick specific amplifications for this section.

A17.3.3.3.5 Supplier Oversight

There are no Brunswick specific amplifications for this section.

A17.3.3.3.6 Independent Audit of QA Functions

There are no Brunswick specific amplifications for this section.

A17.3.3.3.7 Audit Frequency Extensions

There are no Brunswick specific amplifications for this section.

A17.3.4 REVIEW AND AUDIT

The topics in this section were added to the BNP UFSAR description of the QA Program to relocate certain administrative controls from Technical Specifications. Those relocated administrative controls, indicated by section heading, are either contained below or referenced to the current location.

A17.3.4.1 Procedures, Tests, and Experiments

1. The procedures established, implemented, and maintained for the Quality Assurance Program for effluent and environmental monitoring use the guidance in Regulatory Guide 1.21, Revision 1, June 1974 and Regulatory Guide 4.1, Revision 1, April 1975.
2. See Section 17.3.2.14 for required reviews for changes to procedures, tests, and experiments.

A17.3.4.2 Modifications

See Section 17.3.2.2, Design Control for reviews required for modifications.

A17.3.4.3 Operating License/BNP Technical Specifications

1. Operating License/BNP Technical Specification changes shall be processed in accordance with 10CFR 50.90.
2. Operating License/BNP Technical Specification change requests shall be reviewed by

the On-Site Review Committee in accordance with Section 17.3.3.2.

3. Changes to the 61BTH Independent Spent Fuel Storage Installation (ISFSI) BNP Technical Specifications and License are processed by Transnuclear, Inc., and will only be reviewed by the On-Site Review Committee if a plant-specific safety issue is identified.

A17.3.4.4 10CFR 50.59 Evaluations and Independent Review Control

See Section 17.3.4.2, 10 CFR 50.59 Reviews.

A17.3.4.5 Nuclear Reviewers

Technical reviewer qualifications are addressed in Section 17.3.4.1, Technical Reviews and 10 CFR 50.59 evaluator qualifications are addressed in Section 17.3.4.2, 10 CFR 50.59 Reviews.

A17.3.4.6 Plant Nuclear Safety Committee

See Section 17.3.3.2, Independent Review.

Attachment B, Harris Specific QAPD

Harris has received NRC approval to implement 10 CFR 50.69, Risk-informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors. SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of the QAPD as they are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule.

10CFR 50.69, provides alternative approaches for establishing the requirements for treatment of SSCs using a risk informed method of categorization according to safety significance. As part of implementing 10 CFR 50.69, engineering will establish a collection of program elements to monitor and / or maintain SSC critical attributes ensuring reasonable confidence in the continued capability and reliability of the design basis functions. These elements include, inspection and testing, corrective actions, feedback and process adjustments, performance monitoring, program documentation, and reporting, as applicable to meet 10CFR 50.69(d), (e), (f), and (g). DEC implements the requirements of the QAPD commensurate with the safety classification of the SSCs, as described in applicable licensing and design documents, and implementing procedures.

Information presented in this attachment is specific to Harris and was contained in the UFSAR prior to Amendment 41.

Where a section contains no descriptive information beyond that in the generic text in the body of the document, a statement is made to that effect and no content is included. See B17.3.1.2, Organization for example.

B17. QUALITY ASSURANCE

B17.1 QA DURING DESIGN AND CONSTRUCTION

See Harris UFSAR Chapter 17 for historic information from the description of the QA Program for design and construction.

B17.2 OPERATIONAL QA

Deleted

(NOTE: In April 1995, NRC approved the reformatting of the description of the Harris QA Program to follow Standard Revision Plan Section 17.3, replacing the content of 17.2.)

B17.3 HNP QUALITY ASSURANCE PROGRAM (QAP) DESCRIPTION

INTRODUCTION

This content is not addressed in SRP Section 17.3; therefore, the Harris description of the QA Program did not include this section.

DEFINITIONS

Harris specific definitions are found in Table B17.1 addressing conformance with Regulatory Guide 1.74, Quality Assurance Terms and Definitions.

EXPLANATION OF "QUALITY ASSURANCE"

There is no Harris specific content.

QA STANDARDS AND GUIDES

Table B17-1 and B17-2 address QAP conformance to the referenced regulatory and program guidance in NUREG-0800 Section 17.3.

The content of Table B17-1 was transferred from Section 1.8 of the Harris UFSAR. Changes to the content of Table B17-1 are controlled in accordance with 10 CFR 50.54(a). Subsequent changes to the QAP are incorporated in this document as identified in Section 17.3.1.7.

Table B17-2 addresses additional Regulatory Guides that relate to implementation of the QAP but the implementation is site specific and controlled with the Harris UFSAR in accordance with 10 CFR 50.59.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards

Generic Exception:

Table B17-1 addresses the Harris Nuclear Plant (HNP) Conformance of the Quality Assurance Program to certain NRC Regulatory Guides. In so doing, specific editions of industry standards are identified for compliance with exceptions and alternatives. Those identified standards include references to other industry standards for activities including, but not limited to; design, fabrication, inspection, and testing. Those included reference industry standards are considered to be guidance documents for details of how activities may be accomplished. The actual standard to be used in such cases is controlled by each station's current licensing and design bases.

Regulatory Guide 1.28, Quality Assurance Program Requirements (Design and Construction) (Rev 0)
ANSI N45.2-1971, Quality Assurance Program Requirements for Nuclear Power Plants
For those activities performed under operating license, HNP shall comply with the requirements of Regulatory Guide 1.33 as specified in the position on Regulatory Guide 1.33. Regulatory Guide 1.28 is not considered necessary and is not included as part of the operational QA program.
Regulatory Guide 1.30, Quality Assurance Requirements for the Installation and Testing of Instrumentation and Electric Equipment (Rev. 0)
HNP complies with the requirements of ANSI N45.2.4-1972), Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations, as it is endorsed by Regulatory Guide 1.30 with the following clarifications:

1. Section 2.1, planning: requirements, as determined by responsible plant management, will be incorporated into procedures.
2. Sections 2.2 and 2.3; prerequisites, procedures, and instructions: these controls will be implemented as determined by responsible plant management in approved procedures.
3. Section 2.4, results, will be implemented as set forth in 17.3.2.12 and by compliance with Regulatory Guide 1.33.
4. Section 2.5, measuring and test equipment, will be implemented as set forth in 17.3.2.9 in lieu of the requirements set forth in this paragraph.
5. Section 3, preconstruction verification: "approved instructions" are interpreted to include vendor manuals.
6. Section 4, installation, will be implemented by inclusion of requirements in modification or maintenance procedures, where such procedures are used. Standard HNP practices require that appropriate care be exercised whether a procedure is required or not.
7. Section 5.1, inspections, including subsections 5.1.1, 5.1.2, and the first sentence in 5.1.3, will be implemented as set forth in 17.3.2.12. The remaining sentence in 5.1.3 is covered in equivalent detail by HNP's commitment to Regulatory Guide 1.33, Section 5.2.6; the requirements as set forth in that commitment will be implemented in lieu of the requirements stated here.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation and Testing of Instrumentation and Electric Equipment (Rev. 0)

HNP complies with the requirements of ANSI N45.2.4-1972), Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations, as it is endorsed by Regulatory Guide 1.30 with the following clarifications:

8. Section 5.2, tests, including subsections 5.2.1 through 5.2.3, will be implemented as set forth in 17.3.2.8. The test program will consider the elements outlined in this paragraph when developing test requirements for inclusion in maintenance and modification procedures. In some cases, testing requirements may be met by post-installation surveillance testing in lieu of a special post-installation test.
9. Section 6, post-construction verification, is not generally considered applicable at operating facilities because of the scope of the work and the relatively short interval between installation and operation.
10. Section 6.2.1 titled equipment tests: the last paragraph of this section deals with tagging and labeling. HNP will comply with an alternate last paragraph which reads: "Each safety-related component of process instrumentation is identified with a unique number. This number is utilized in instrument maintenance records so that current calibration status, including data such as the date of the calibration and identity of person that performed the calibration, can be readily determined. Such information may also be contained on tags or labels which may be attached to installed instrumentation."
11. Section 7, data analysis and evaluation, will be implemented as stated with adding the clarifying phrase "when used" at the beginning of that paragraph. The plant shall have procedures, to the extent determined by responsible plant management, for the performance of analyzing test data, but these procedures are not referred to as data processing procedures.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Rev. 2) (Operation)

HNP complies with this guide, which endorses ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants, with the following clarifications:

1. Section 1,"Scope", recommends that this standard applies to activities other than those associated with safety related equipment, activities, and procedures. ANSI N18.7-1976 has not fully taken into account the requirements of regulations other than 10CFR 50. Conflicts may exist between ANSI N18.7-1976 and those other regulations, such as OSHA, 10CFR 19, 20, 21, 30, 40, 70, 71, 73, and ASME. Therefore, HNP shall apply ANSI N18.7-1976 only to those plant features addressed in Section 3.2 of the HNP UFSAR that are classified as safety-related and under the control of the QA program.
   - (A) SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document. These 50.69 LSS SSCs are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule.
   - (B) Procedures provide guidance for specific process changes as part of 10 CFR 50.69 implementation.
2. Written audit reports are not formally reviewed as part of the independent review function.
3. The CNO will assure that an independent assessment of the overall nuclear oversight program is conducted at least once every 24 months. See Section 17.3.3.3.6 Independent Audit of QA Functions.
4. Section 5.2.6, Equipment Control: HNP will comply with the "independent verification"

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

requirements based on the definition of this phrase as given under the commitment to Regulatory Guide 1.74.

Since HNP sometimes uses descriptive names to designate equipment, the sixth paragraph, second sentence is replaced with: "Suitable means include identification numbers or other descriptions which are traceable to records of the status of inspections and tests.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Rev. 2) (Operation)

HNP complies with this guide, which endorses ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants, with the following clarifications:

The first sentence in the seventh paragraph will be complied with after clarifying "operating personnel" to mean trained employees assigned to, or under the control of, Duke Energy management at an operating nuclear facility.

5. Section 5.2.7, Maintenance and Modification: since some emergency situations could arise which preclude preplanning of all activities, HNP will comply with an alternate to the first sentence in the second paragraph which reads:
   "Except in emergency or abnormal operating conditions where immediate actions are required to protect the health and safety of the public, to protect equipment or personnel, or to prevent the deterioration of plant conditions to a possible unsafe or unstable level, maintenance or modification of equipment shall be preplanned and performed in accordance with written procedures. Where written procedures would be required and are not used, the activities that were accomplished shall be documented after the fact and receive the same degree of review as if they had been preplanned." where procedures are not available, documented instructions may be used to perform maintenance and modification activities. "Documented instructions" are defined as any credible information (e.g., vendor manuals, vendor recommendations, engineering direction etc.) used during work planning/execution which is reviewed and approved prior to use in accordance with approved procedures.
   Section 5.2.7.1, Maintenance Programs: HNP will comply with the requirements of the first sentence of the fifth paragraph. This clarification is needed since it is not always possible to promptly determine the cause of the malfunction. HNP will initiate proceedings to determine the cause, and will make such determination promptly where practical. Determination of the term "promptly" and the term "practical" will be the responsibility of plant management and shall be based on the effect of the condition on the immediate health and safety of the public.
6. Section 5.2.8, Surveillance Testing and Inspection Schedule: In lieu of a "master surveillance schedule," the following requirement shall be complied with: "surveillance testing schedule(s) shall be established reflecting the status of all planned in-plant surveillance tests and inspections."
7. Section 5.2.9, Plant Security and Visitor Control, requires certain procedures and controls. In order to ensure that a conflict between 10CFR 73 and Regulatory Guide 1.17 and ANSI N18.17 does not exist, HNP shall not follow Section 5.2.9. An NRC approved security plan was implemented prior to fuel loading.
8. Section 5.2.11, Corrective Action, requires certain activities to be performed. In order to avoid conflict between requirements, HNP shall follow the requirements in Sections 17.3.1.6 and 17.3.2.13, in lieu of Section 5.2.11.
9. Section 5.2.13.1, Procurement Document Control: When purchasing commercial-grade calibration services from certain accredited calibration laboratories, the procurement documents are not required to impose a quality assurance program consistent with ANSI N45.2-1971. Alternate requirements described in this table for Regulatory Guide 1.123 may be implemented in lieu of imposing a quality assurance program consistent with ANSI N45.2-1971. When purchasing nuclear safety related material, equipment and services, the

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

supplier is required to the meet applicable criteria of 10 CFR 50, Appendix B and 10 CFR 21– with the exception that SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document. These 50.69 LSS SSCs are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule. Procedures provide guidance for specific process changes as part of 10 CFR 50.69 implementation.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Rev. 2) (Operation)

HNP complies with this guide, which endorses ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants, with the following clarifications:

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10. Section 5.2.15, Review, Approval and Control of Procedures: The third sentence in paragraph three is interpreted to mean: "Applicable procedures shall be reviewed following an accident, an unexpected transient or a significant operator error. Applicable procedures shall also be reviewed following an equipment malfunction which results in a reportable event."

    Section 5.2.15 titled Review, Approval and Control of Procedures, states that, "Plant procedures shall be reviewed by an individual knowledgeable in the area affected by the procedure no less frequently than every two years to determine if changes are necessary. A revision to a procedure constitutes a procedure review." In lieu of this commitment, Duke Energy addresses programmatic controls in Section 17.3.2.14 to continually identify procedure revisions which may be needed to ensure that procedures are appropriate for the circumstance and are maintained current.
11. Section 5.2.16, Measuring and Test Equipment - In order to properly address this paragraph, HNP submits the following discussion of M&TE:

    IEEE Standard 498-1975 defines measuring and test equipment (M&TE) as follows: Devices or systems used to calibrate, measure, gauge, test, inspect, or control in order to acquire research, development, test, or operational data to determine compliance with design, specifications, or other technical requirements. M&TE does not include permanently installed operating equipment or test equipment used for preliminary checks where accuracy is not required; for example, circuit checking multimeters.

    Note: M&TE does not include rules, tape measures, levels, and other devices if normal commercial practices provide adequate accuracy.

    There is a key distinction between installed process instruments and measuring and test equipment. A piece of measuring and test equipment may be used to calibrate a number of plant instruments. Thus, a calibration error could affect a wide variety of plant equipment. Process instruments, on the other hand, perform a single function and may be used to operate equipment, verify operability of equipment, or perform a single monitoring or trip function. In the case of measuring and test equipment, the key concern when a device is out of calibration is to identify other instruments to which this accuracy has been transferred and, secondly, to prevent recurrence. In the case of process instruments, the key emphasis is to prevent recurrence of the out-of-calibration condition.

    In ANSI N18.7-1976 (and other documents), the distinction between measuring and test equipment and process instruments is not well defined.

    The requirements in the second and third paragraphs in Section 5.2.16 will be applied to measuring and test equipment and those in the first and third paragraphs applied to process instruments with the exception that process instrumentation shall be "suitably marked or tracked to indicate calibration status" versus "suitably marked to indicate calibration status." in addition, a review of out-of-calibration process instruments will be made to determine if action is required to prevent recurrence. Such action may include modification, procedural

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

revision, or corrective maintenance. Section 17.3.2.9 provides additional requirements for control of M&TE.

12. Section 5.2.17, Inspections: As a general clarification, when inspections are not contained in a separate inspection report, inspection requirements will be integrated into appropriate procedures or other documents with the procedure or document serving as the record. Records of inspections will be identifiable and retrievable.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Rev. 2) (Operation)

HNP complies with this guide, which endorses ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants, with the following clarifications:

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13. Section 5.2.17, second to the last sentence in the last paragraph, "Deviations, their cause, and any . . .", to be consistent with Section 5.2.11, the cause of the condition will be determined for only significant conditions adverse to safety.
14. Section 5.3.5(4), HNP interprets the review requirements for "supporting maintenance documents" which have not been incorporated in a procedure, be performed in an equivalent manner as described in approved procedures.
15. Section 5.3.6, Radiation Control Procedures, Discusses certain control programs. As previously stated, Section 1, scope, of ANSI N18.7-1976 references those activities involved with being safety-related.
    The radiation protection program is not considered to be in this category but rather a program required to comply with 10CFR 19, 20, 30, 70, 71, and 100. Therefore, HNP shall develop its radiation protection program as stated in Section 12.5 of the HNP UFSAR.
16. Section 5.3.9.3, Emergency Procedures: As directed by the NRC, HNP will follow a format for emergency procedures in accordance with 10CFR 50, Appendix E.
17. Exception to Paragraph C.3 of Regulatory Guide 1.33 and ANSI N18.7-1976 Section 4.3: Independent Review Program requirements are replaced by Section 17.3.3.2, Independent Review. This exception uses NRC Safety Evaluation dated January 13, 2005 to Nuclear Management Company (ADAMS ML050210276).
18. Regulatory position C.4 modifies the audit frequencies in Section 4.5 of ANSI N18.7. Duke Energy takes exception to this regulatory position. The audits of selected aspects of operational phase activities as identified in Section 17.3.3.3.3, Internal Audit Program, are scheduled based on plant performance and importance to safety but at a frequency not to exceed twenty-four months with extensions as allowed in Section 17.3.3.3.7, Audit Frequency Extensions.
19. Paragraph C.5.d of the Regulatory Guide 1.33 will be implemented by adding the clarifying phrase "Where practicable" in front of the fourth sentence of the fifth paragraph. The Regulatory Guide's changing of the two uses of the word "should" in this sentence to "shall" unnecessarily restricts HNP's options on repair or replacement parts. It is not always practicable to test parts prior to use. Modification review in accordance with the provisions of 10CFR 50.59 will be conducted and documented.
    The words "where practical" will be determined by responsible plant management and the results documented.
20. Paragraph C.5.e of Regulatory Guide 1.33 will be implemented subject to the same clarifications made for ANSI N45.2.2.
21. Paragraph C.5.f of Regulatory Guide 1.33 will be implemented with the substitution of the word "practical" for the word "possible" in the last sentence.
22. Paragraph C.5.g of Regulatory Guide 1.33 will be implemented with the addition of the modifier "normally" after each of the verbs (should) which the regulatory guide converts to "shall". It is HNP's intent to fully comply with the requirements of this paragraph, and any conditions which do not fully comply will be documented and approved by the plant staff. In

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

these cases, the reason for the exception shall be retained for the same period of time as the affected preoperational tests.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Rev. 2) (Operation)
HNP complies with this guide, which endorses ANSI N18.7-1976, Administrative Controls and Quality Assurance for the Operational Phase of Nuclear Power Plants, with the following clarifications:

23. Section 5.2.2, Procedure Adherence describes that for temporary changes to procedures that one of the approvers shall be the supervisor in charge of the shift and hold a senior reactor operator license. To avoid overloading the supervisor in charge of the shift with administrative tasks, any member of operation's management with a senior reactor operator license will be allowed to approve temporary changes to procedures. The change is documented and, if appropriate, reviewed and approved for incorporation in the next revision of the procedure within 14 days of implementation of the temporary change.
24. Section 5.3.10 of ANSI N18.7-1976/ANS-3.2, the last sentence in the first paragraph requires "test and inspection results, shall be documented and evaluated..." also, the last sentence in the second paragraph requires "the test and inspection procedures shall require recording the date, identification of those performing the test or inspection, as-found condition, corrective actions performed, if any, and as-left condition." as an alternative to the records required for inspections outlined in Section 5.3.10, HNP shall provide the following as the method to document results of inspections:
    the results of inspections will be documented in appropriate records and those records shall, as a minimum, identify (A) through (H) below:
    (A) authorized individual approving results.
    (B) date of inspection.
    (C) inspector/data recorder.
    (D) item inspected.
    (E) M&TE used.
    (F) reference to information on action taken in connection with non-conformances.
    (G) results or acceptability.
    (H) type of observation.

Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants (Rev. 0)
HNP shall comply with the requirements of ANSI N45.2.1-1973, Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.37-March 1973, with the following clarifications:

1. Section 2.5, Test Equipment, outlines control of inspection and test equipment. HNP has addressed its position relative to measuring & test equipment (M&TE) in 17.3.2.9.
2. Section 5, Installation Cleaning: The recommendation that local rusting on corrosion resistant alloys be removed by mechanical methods is interpreted to mean that local rusting may be removed mechanically, but the use of other removal means is not precluded provided other cleaning methods are not considered detrimental as determined by responsible plant management.
3. The guide and standard are applicable to those areas of the quality assurance program addressing on-site cleaning of materials and components, cleanness control, preoperation cleaning and layup of fluid systems.
4. With regard to paragraph C.3 of Regulatory Guide 1.37: Chromates or other additives, normally in the system water, will not necessarily be added to the flush water.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants (Rev. 0)

HNP shall comply with the requirements of ANSI N45.2.1-1973, Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.37-March 1973, with the following clarifications:

5. With regard to paragraph C.4 of Regulatory Guide 1.37: Expendable materials, such as inks and related products; temperature indicating sticks; tapes; gummed labels; wrapping materials; water soluble dam materials; lubricants, NDT penetrant materials and couplants, desiccants, which contact stainless steel or nickel alloy surfaces shall be of commercial quality. Levels for halogens, sulfur, chlorides, low melting point metal, etc., for use on stainless steel and nickel alloy surfaces will be as determined by responsible technical group to limit or preclude intergranular cracking and stress corrosion cracking.

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Rev. 2)

HNP shall comply with the requirements of ANSI N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.38 with the following clarifications:

1. Section 2.1, Planning: (first sentence) the specific items to be governed by the standard shall be identified. However, the standard is part of the HNP QA program and it will, therefore, be applied to those structures, systems, and components which are included in that program.
2. Section 2.3 - Results - The full requirements of this paragraph shall apply to the inspections and tests that are performed to determine the acceptability of product quality.
3. Section 2.4 - those personnel that perform inspection, examination, and testing activities for verification and acceptance/rejection purposes shall be qualified in accordance with Regulatory Guide 1.58.
4. Section 2.5 - Measuring and Test Equipment (2.5.2) - That equipment which measures quality of the permanent plant items shall be under the calibration and control program; whereas the equipment used to measure secondary conditions, such as warehouse temperature, humidity, etc., will be maintained in good working order and checked for proper functioning when accuracy is in doubt, but not maintained under the calibration and control program. Traceability to calibration records will be provided when it is impractical (because of size, configuration, or application) to physically mark calibration information on the item. Note: M&TE does not include rulers, tape measures, levels, and other devices if normal commercial practices provide adequate accuracy.
5. Section 2.7, Classification of Items: HNP may choose not to explicitly use the four level classification system. However, the specific requirements of the standard that are appropriate to each class will be applied unless justified and documented.
6. Section 2.7.1(3) requires special nuclear material (fuel) and sources to be classified as Level A. HNP shall store new/used nuclear fuel and radioactive sources in storage locations as described in the Chapters 9 and 12 of the UFSAR. Radioactive sources used by HP personnel shall be stored and controlled in accordance with HP practices and procedures.
7. Section 3.2 - Levels of Packaging - Packaging for shipment off-site will be equal to or exceed the original packaging by the vendor, as required to assure the quality of the item is not degraded as a result of shipping or handling.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Rev. 2)

HNP shall comply with the requirements of ANSI N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.38 with the following clarifications:

8. Section 3.4, Methods of Preservation: (first sentence) HNP will comply with these requirements subject to the clarification that the term "deleterious corrosion" means corrosion which cannot be subsequently removed and which adversely affects form, fit, or function.
9. Section 3.6 - Barrier and Wrap Materials and Desiccants - The use of clear plastic in warehouses will be minimized. The guide rule is that the clear plastic shall be used only where periodic visual inspection is necessary.
   Plastic wrap on items supplied in accordance with a vendor's approved QA/QC program will be accepted and stored without rewrapping.
10. Section 3.7, Containers, Crating and Skids: In lieu of the requirements of this paragraph, HNP will use means as determined by responsible plant technical personnel needed to provide adequate protection of the items in storage.
11. Section 4 - Shipping - Requirements of Section 4, Shipping, primarily applies to the vendor. Plant functions with regard to return shipments will meet or exceed the methods of the vendor for the item or approved alternatives.
12. Section 5.2.1, Shipping Damage Inspection: Warehouse personnel will normally visually scrutinize incoming shipments for damage of the types listed in this paragraph; this activity is not necessarily performed prior to unloading. Since required items receive the item inspection of Section 5.2.2, separate documentation of the shipping damage inspection is not necessary. Release of the transport agent after unloading and the signing for the receipt of the shipment may be all of the action taken to document completion of the shipping damage inspection. Any nonconformances noted will be documented and dispositioned as required by 17.3.2.13. The person performing the visual scrutiny during unloading is not considered to be performing an inspection function as defined under Regulatory Guide 1.74; therefore, while he will be trained and qualified to perform this function, he may not necessarily be certified (N45.2.6) as an inspector.
13. Section 5.2.2, Item Inspection: The need and extent for inspection of items will be determined by responsible plant technical personnel. Receiving inspections shall be performed in an area designated for receipt of material and shall normally be performed in the receiving building. The receiving building and the areas designated will provide adequate protection for the material, but may not comply with all of the specific requirements contained in Section 6 of this standard. Material that is suspected of being compromised during the receiving process shall be evaluated by responsible technical personnel, as determined by plant management.
14. Section 5.2.2(1) - Identification and Marking - Item inspection will include inspection for identification and marking required by the purchase order documents. Marking that is not quality related or which provides no traceability will not be inspected.
15. Section 5.3.1 - Acceptable - Item acceptance status will be indicated by application of tags, stickers, ribbons, or signs. Storage areas are not designated as accept areas except for bulk items.

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Rev. 2)

HNP shall comply with the requirements of ANSI N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants, as it is endorsed by Regulatory Guide

16. Section 6.1.1 - Scope - The levels and methods of storage for items between the time of removal from the prescribed storage until placement in the installed location may be relaxed as determined by responsible plant management for short periods of time, according to the sensitivity of the item being handled and the elements of contact anticipated during this interval. Where relaxation of storage requirements of this standard are deemed appropriate, the item, conditions, precautions and follow-up inspection for assurance that quality of the item has been maintained will be documented.
17. Section 6.1.2, Levels of Storage: Subpart (2) is replaced with the following:
    (2) Level B items shall be stored within a fire-resistant, weather-tight, and well ventilated building or equivalent enclosure. This building shall be situated and constructed so that it will not normally be subject to flooding; the floor shall be paved or equal, and well drained. If any water comes in contact with stored equipment, such equipment will be labeled or tagged nonconforming, and then the nonconformance document will be processed and evaluated. Items shall be placed on pallets, shoring, or shelves to permit air circulation. The building shall be provided with heating and temperature control or its equivalent to reduce condensation and corrosion. Minimum temperature shall be 40°F and maximum temperature shall be 140°F or less if so stipulated by a manufacturer.
18. Section 6.2.1, Access to Storage Areas: Items which fall within the level d classification of the standard will be stored in areas which may be posted to limit access, but other positive controls such as fencing or guards will not normally be provided.
19. Section 6.2.4, Storage of Food and Associated Items: The sentence is replaced with the following: "The use or storage of food, drinks, and salt tablet dispensers in any storage area shall be controlled and shall be limited to designated areas where such use or storage is not deleterious to stored items."
20. Section 6.2.5, Measures to Prevent Entrance of Animals: The sentence is replaced with the following: "Warehouse personnel shall be alert to detect evidence of rodents or small animals in indoor storage areas.
    Consideration will be given when setting up the system to provide reasonable assurance that rodents or other small animals will not be present. If any such evidence is detected, a survey or inspection will be utilized to determine the extent of the damage; exterminators or other appropriate measures shall be used to control these animals to minimize possible contamination and mechanical damage to stored material."
21. Section 6.3.3, Storage of Hazardous Material: The sentence is replaced with the following: "Hazardous chemicals, paints, solvents, and other materials of a like nature shall be stored in approved cabinets or containers which are not in close proximity to installed safety systems required for safe shutdown."
22. Section 6.4.2, Care of Items: The following alternates are provided for indicated subparts:
    (5) "Space heaters in electrical equipment shall be energized unless a documented engineering evaluation determines that such space heaters are not required."
    (6) "Large (greater than or equal to 50 hp) rotating electrical equipment shall be given insulation resistance tests on a scheduled basis unless a documented engineering evaluation determines that such tests are not required."

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Rev. 2)

HNP shall comply with the requirements of ANSI N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.38 with the following clarifications:

(7) "Prior to being placed in storage, rotating equipment weighing over approximately 50 pounds shall be evaluated by engineering personnel to determine if shaft rotation in

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

storage is required; the results of the evaluation shall be documented. If rotation is required, it shall be performed at specified intervals, and documented.

The degree of turn shall be established so that the parts receive a coating of lubrication where applicable, and so that the shaft does not come to rest in the position prior to rotation. (90 deg. and 450 deg. rotations are examples.) For long shafts or heavy equipment subject to undesirable bowing, shaft orientation after rotation shall be specified and obtained."

(8) Other maintenance requirements specified by the manufacturer's instructions shall be evaluated by responsible plant personnel to determine applicability during storage of the item.

23. Section 6.5, Removal of Items from Storage: HNP does not consider the last sentence of this paragraph to be applicable to the operations phase due to the relatively short period of time between installation and use. The first sentence of the paragraph is replaced with: "HNP will develop, issue, and implement a procedure(s) which cover(s) the removal of items from storage. The procedure(s) will assure that the inspection status of all material issued is known, controlled, and appropriately dispositioned."
    When items are released and waiting at a location prior to installation, responsible plant management in accordance with plant procedures will determine and document the extent of inspection and storage requirements.
24. Section 6.6, Storage Records: HNP will comply with the requirements of this section with the clarification that, for record purposes, personnel access to storage areas will not be recorded. Unloading or pick-up of material shall not be considered "access," nor shall inspection by NRC or other regulatory agents, nor shall tours by non-HNP employees who are accompanied by HNP employees.
25. Section 7.3 - Hoisting Equipment - The load chart for each crane includes the model number for that crane. This load chart is considered to be "certification" by the manufacturer for that crane as required by Section 7.3.1. Likewise, forklifts are considered certified by the manufacturer's literature giving maximum capacity as required by Section 7.3.2.
    Section 7.3, Hoisting Equipment: Rerating of hoisting equipment will be considered only when absolutely necessary. Prior to performing any lift above the load rating, the equipment manufacturer will be contacted for his approval and direction. The manufacturer will be requested to supply a document granting approval for a limited number of lifts at the new rating and any restrictions involved, such as modifications to be made to the equipment, the number of lifts to be made at the new rating, and the test lift load. At all times, the codes governing rerating of hoisting the equipment will be complied with.
    If rerating of hoisting equipment is necessary and HNP cannot or does not contact the equipment manufacturer as described above, the test weight used in temporarily rerating hoisting equipment for special lifts will be at least equal to 110 percent of the lift weight. A dynamic load test over the full range of the lift using a weight at least equal to the lift weight will be performed.

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (Rev. 2)

HNP shall comply with the requirements of ANSI N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.38 with the following clarifications:

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26. Section 7.4 - Inspection of Equipment and Rigging - Nondestructive examinations will be performed by QC personnel qualified in accordance with Regulatory Guide 1.58 (except as amended by safety analysis report position). Operators will be trained in the operation and maintenance inspections of their assigned equipment.
27. Appendix A.3.5.1 - Caps and Plugs; A.3.5.2, Tapes and Adhesives; and A.3.6.3, Desiccants

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

- Plugs, caps, tapes, adhesives, desiccants, markers and other temporary items will be of commercial quality. Levels for halogens, sulfur, chlorides, low melting point metal, etc., for use on stainless steel and nickel alloy surfaces will be as determined by the responsible technical group to limit or preclude intergranular cracking and stress corrosion cracking.

Regulatory Guide 1.39, Housekeeping Requirements for Water Cooled Nuclear Power Plants (Rev. 2)
HNP complies with the requirements of ANSI N45.2.3-1973, Housekeeping, During the Construction Phase of Nuclear Power Plants, as endorsed by Regulatory Guide 1.39, September 1977, with the following clarifications for:
1. Section 2.1, Planning: The zone designations provided in the standard will be used as a guide in developing plant procedures; however, plant areas will not necessarily be divided into zones I through V. Equivalent controls will be maintained as prescribed in approved procedures. 2. Section 3.5, Surveillance, Inspection, and Examinations: Subsection (1) is not applicable during normal operations but will be implemented if large items are to be moved or handled.

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination and Testing Personnel (Rev. 1)
HNP shall comply with NRC Regulatory Guide 1.58, Revision 1, which endorses ANSI N45.2.6-1978, Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants, with the following clarifications:
1. With regard to Section 1.2 of ANSI N45.2.6-1978 titled <u>Applicability</u>: HNP elects not to apply the requirements of this guide to those personnel who are involved in the daily operations of surveillance, maintenance, and certain technical and support services whose qualifications are controlled by 17.3 or are controlled by other QA program commitment requirements. Only personnel in the following listed categories will be required to meet ANSI N45.2.6-1978 requirements: (1) nondestructive examination (NDE) personnel (2) QC inspection personnel, and (3) receipt inspection personnel. 2. The fourth paragraph of Section 1.2 requires that the standard be imposed on personnel other than HNP employees. The applicability of the standard to suppliers and contractors will be documented and applied as specified in the procurement documents for each supplier and contractor or in interface agreements for Duke Energy non-nuclear organizations providing services identified in Section 17.3.1.2.3.

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination and Testing Personnel (Rev. 1)
HNP shall comply with NRC Regulatory Guide 1.58, Revision 1, which endorses ANSI N45.2.6-1978, Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants, with the following clarifications:
3. With regard to Section 2.5 of ANSI N45.2.6-1978 titled <u>Physical</u>: HNP will implement the requirements of this section with the stipulation that, where no special physical characteristics are required, none will be specified. The converse is also true: if no special physical requirements are stipulated by HNP, none are considered necessary. HNP employees receive an initial physical examination to assure satisfactory physical condition; however, only the following listed personnel will receive an annual examination: (1) NDE personnel (2) QC inspection personnel, and (3) receipt inspection personnel. This annual examination shall consist of the near visual acuity using the standard Jaeger's type chart or equivalent test.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

4. With regard to Section 3 of ANSI N45.2.6-1978 titled Qualifications: Only personnel performing NDE (such as LP, MT, UT, and RT) are required to be grouped in levels of capability and certified for inspection, review, and evaluation of inspection data, and reporting of inspection and test results. Inspection personnel are qualified based on pre-established experience, education, on-the-job training, written examinations and proficiency tests associated with the specific activity. Proficiency tests are given to personnel performing independent QC inspections and documented acceptance criteria are developed to determine if individuals are properly trained and qualified. Certificates of qualification delineate the functions personnel are qualified to perform. Qualification records are maintained and performance evaluations conducted at least once every three years. If organizations elect to utilize qualifications by levels for non-NDE inspections, Level I inspectors receive a minimum of 4 months experience as Level I before being certified as Level II, in lieu of one year experience recommended by ANSI N45.2.6 Section 3.5.2(1). Organizations identify in their procedures if they qualify their inspectors by Level or by task qualifications. Inspectors are only assigned functions for which they have been qualified.
5. With regard to Section 3.5 of ANSI N45.2.6-1978 titled Education & Experience Recommendations: HNP will certify individual inspectors through training and experience to requirements appropriate to the specific assignment; however, except for NDE, personnel are not required to be classified by levels of capability. The training experience requirements will be directed toward qualifying personnel for specific inspection and testing operations.

Regulatory Guide 1.64, Quality Assurance Requirements for the Design of Nuclear Power Plants (Rev. 2)
HNP shall comply with NRC Regulatory Guide 1.64, Rev. 2, which endorses ANSI standard N45.2.11-1974, Quality Assurance Requirements for the Design of Nuclear Power Plants, with the following clarification:
Regulatory Guide 1.64, Paragraph C.2(1): For the exceptional circumstance in which the designer's immediate supervisor is the only technically qualified individual available, this review can be conducted by the supervisor, provided that: i) the other provisions of the regulatory guide are satisfied, ii) the justification is individually documented and approved in advance by the supervisor's management, and iii) quality assurance audits cover frequency and effectiveness of the use of supervisors as design verifiers to guard against abuse.
Regulatory Guide 1.74, Quality Assurance Terms and Definitions (Rev. 0)
Regulatory Guide 1.74 endorses ANSI N45.2.10-1973, Quality Assurance Terms and Definitions. The HNP project complies with this guide as described below:
HNP complies with the requirements of this guide with the following clarifications:

1. HNP reserves the right to define additional words or phrases which are not included in this standard. Such additional definitions will be documented in appropriate procedures, manuals, etc.
2. In addition to the standard's definition of "inspection," HNP will use the following: "Inspection (when used to refer to activities that are not performed by quality organization personnel) - examining, viewing closely, scrutinizing, looking over or otherwise checking activities. Personnel performing these functions are not necessarily certified to ANSI N45.2.6."

   When HNP intends for inspection to be performed in accordance with the QA program by personnel certified as required by that program and for activities defined by "Inspection" in ANSI N45.2.10, appropriate references to the plant quality organization which will perform the activity and/or to quality procedures to be used for performing the

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

activity will be made. If such references are not made, inspections are considered under the additional definition given above.

3. In addition to the standard's definition of "procurement documents," HNP will utilize the definitions given in ANSI N45.2.13 and in Regulatory Guide1.74. The compound definition, procurement documents-contractually binding documents that identify and define the requirements which items or services must meet in order to be considered acceptable by the purchaser. They include documents which authorize the seller to perform services or supply equipment, material or facilities on behalf of the purchaser (e.g. contracts, letters of intent, work orders, purchase orders, or proposals and their acceptance, drawings, specifications, or instructions which define requirements for purchase).
4. "Quality assurance program requirements" (not defined in ANSI N45.2.10, but used and defined differently in ANSI N45.2.13) - those individual requirements of the QA program which, when invoked in total or in part, establish the requirements to the quality assurance program for the activity being controlled. Although not specifically used in the operational QA program, ANSI N45.2 may be imposed upon HNP's suppliers.
5. "Independent Verification" - Verification that required actions have been completed by an individual other than the person who performed the operation or activity being verified. Such verification will not require confirmation of the identical action when other indications provide assurance or indication that the prescribed activity is in fact complete. Examples include, but are not limited to: verification of a breaker opening by observing remote breaker indication lights; verification of a set point (made with a voltmeter or ammeter for example) by observing the actuation of status or indicating lights are the required panel-meter indicated value; verification that a valve has been positioned by observing the starting or stopping of flow on meter indications or by remote valve position indicating lights.
6. "Audit" (will be a modification of the word - to allow the use of subjective evidence if available - as defined in Section 1.4 of ANSI N45.2.12-1977 and Section 1.4.3 of ANSI N45.2.23-1978 as opposed to the definition given in ANSI N45.2.10-1973) - A documented activity performed in accordance with written procedures or checklists to verify, by examination and evaluation of objective evidence where available, that applicable elements of the quality assurance program have been developed, documented, and effectively implemented in accordance with specified requirements. An audit should not be confused with surveillance or inspection for the sole purpose of control or product acceptance.

Regulatory Guide 1.88, Collection, Storage and Maintenance of Nuclear Power Plant Quality Assurance Records (Rev. 2)

HNP shall comply with NRC Regulatory Guide 1.88, Rev. 2, which endorses ANSI N45.2.9-1974, Collection, Storage, and Maintenance of QA Records, with the following clarifications:

See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.

1. Appendix A of ANSI N45.2.9 is not considered to be a mandatory list. This list will be used as a guideline for classifying those documents that need to be maintained as QA records. Whether a particular type of document needs to be classified as a QA record and its appropriate retention period is determined in accordance with records management procedures.
2. Section 1.4, Definitions: The phrase "When the document has been completed" is clarified to mean when the document has received the final review performed by the organizational element responsible for generating or collecting the records. In the case of a record package (plant change request, equipment qualification, etc.) made up of several individual documents, the package will be considered to be the document for the purpose of determining when the document is complete.
3. Section 3.2.1, Generation of Quality Assurance Records: The phrase "Completely filled out"

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

is clarified to mean that sufficient information is recorded to fulfill the intended purpose of the record.

4. Section 3.2.2, Index: The storage location will be delineated in procedures in lieu of in the index. The specific location of a record "within a storage area" is delineated by a computerized indexing system plus a storage area labeling system which provides information by record type and storage medium.
5. Section 4.2, Timeliness: HNP 's contractual agreement with its contractors and suppliers will constitute fulfillment of the requirements of this paragraph.
6. Section 5.4, Preservation: The following clarification is substituted for the current Subsection 5.4.2: "Records shall not be stored loosely. They shall be secured for storage in file cabinets or on shelving in containers." the following clarification is substituted for the current Subsection 5.4.3: "appropriate provisions shall be made for special processed records (such as radiographs, photographs, negatives, microfilm, and magnetic media) to prevent or minimize damage from excessive light, stacking, electromagnetic fields, temperature and humidity, etc. Manufacturer's recommendations will be considered as appropriate."
7. Section 5.5, Safekeeping: Routine general office and nuclear site security systems and access controls are provided. No special security systems are required to be established for record storage areas.
8. Section 5.6, Facility: This paragraph provides no distinction between temporary and permanent facilities. To cover temporary storage, the following clarification is added: "complete records may be stored in one-hour fire rated file cabinets until transmitted for permanent storage. In general, records shall not be maintained in temporary storage for more than ninety days after completion.
   Any exceptions to this requirement must be justified, evaluated and approved by the supervisor document services or designee and documented. A list of exceptions shall be maintained and available for NRC review. Exceptions may include records needed on a continuing basis for an extended period of time at the location of the work group responsible for generating the records and records which are cumulative in nature and could best be turned over for storage for a designated period of time."

Regulatory Guide 1.88, Collection, Storage and Maintenance of Nuclear Power Plant Quality Assurance Records (Rev. 2)

HNP shall comply with NRC Regulatory Guide 1.88, Rev. 2, which endorses ANSI N45.2.9-1974, Collection, Storage, and Maintenance of QA Records, with the following clarifications:

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9. Section 5.6, subparagraph 3, is clarified to require a two-hour minimum fire rating to be consistent with the 1979 version of the standard and NRC Criteria for Record Storage Facilities (Guidance - ANSI N45.2.9, Section 5.6) issued 7/1/80.
10. Section 5.6, subparagraph 9, is clarified to read: "No pipes or penetrations except those providing fire protection, lighting, temperature/humidity control or communications are to be located within the facility. All such penetrations shall be sealed or dampened to comply with a minimum two-hour fire protection rating."
11. Additional clarification for QA records is provided in Section 17.3.2.15.
12. See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.
13. See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.

Regulatory Guide 1.94, Quality Assurance Requirements for Installation, Inspection and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants (Rev. 1)

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

HNP complies with the requirements and guidance of ANSI N45.2.5-1974, Supplementary Quality Assurance Requirements for Installation Inspections and Testing of Structural Steel During the Contract Phase of Nuclear Power Plants, as it is referenced in Regulatory Guide 1.94, Rev. 1, with the following clarifications:

A) Section 2.1, Planning: Requirements, as determined by responsible plant management, will be incorporated into procedures.
B) Section 2.3, Results, Will be implemented as set forth in Sections 17.3.2.12, 17.3.2.8, and 17.3.2.15 and Regulatory Guide 1.33.
C) Section 2.5 of ANSI N45.2.5, Measuring & Test Equipment, Requires certain controls over this type of equipment. The equipment listed shall be included in the calibration control program; however, the basis and control of measuring and test equipment is that stated in Section 17.3.2.9.
D) The cement test frequency for standard physical and chemical properties is in accordance with ASTM C 183, on the basis of one test per daily production at the cement plant, reference ANSI N45.2.5, Table B. Table B also lists a test frequency for ASTM C 235 which has been discontinued by ASTM. HNP plans to discontinue testing in accordance with ASTM C 235. Acceptance of aggregates for durability/hardness will be in accordance with ASTM C 131 OR C 535, Los Angeles Abrasion Test.
E) Gradation - In addition to the gradations listed in ASTM C-33, an aggregate designated 78-M (State of North Carolina designation) is used in special areas such as around major penetrations or in reinforcing steel congested areas, with the approval of the engineers. This aggregate meets all other qualifications of ASTM C-33, with the exception of gradation analyses. The results during preliminary concrete mix design have been satisfactory and in accordance with the requirements of ASME Section III, Division 2/ACI-359 code.
F) Section 5.4, High Strength Bolting: Bolting connection points will be visually inspected in accordance with ANSI N45.2.5-1974 except that bolt length will be checked to ensure bolts are long enough as indicated by the point of the bolts being flush with or outside the face of the nuts in accordance with ANSI N45.2.5-1978.

Regulatory Guide 1.116, Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems, (Rev. 0-R)

HNP complies with the requirements of ANSI N45.2.8-1975, Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems for the Construction Phase of Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.116, Revision O-R, June 1976, with the following clarifications:

1. Section 2.1, Planning: Requirements, as determined by responsible plant management, will be incorporated into procedures.
2. Section 2.3, results, will be implemented as set forth in Section 17.3.2.12 and by compliance with RG 1.33.
3. Section 2.8, Measuring and Test Equipment - HNP has addressed this requirement for the operational phase of the plant in Section 17.3.2.9.
4. Section 2.9, Prerequisites, References requirements of other standards. HNP has addressed applicable standards in the appropriate sections of the HNP UFSAR in lieu of the requirements of this paragraph. The extent to which this paragraph applies will be determined by responsible plant management based on end use and complexity of the item.
5. Section 3.3, Processes and Procedures: "Approved instructions" are interpreted to include vendor manuals.
6. Section 4.6, Care of Items: This will be done as outlined in the position on Regulatory Guide 1.38.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

7. Section 5, including subsections 5.1 through 5.4, Installed Systems, Inspections and Tests: Responsible plant management will determine the extent to which the elements in this paragraph are applied when developing test requirements for inclusion in modification procedures. In some cases, testing requirements may be met by post-installation surveillance testing in lieu of a special post-installation test.

Regulatory Guide 1.123, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, (Rev. 1)

HNP shall comply with the requirements of ANSI N45.2.13-1976, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.123 with the following clarifications:

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1. Section 1.2.2, Purchaser's Responsibilities: Item C is one of the options which may be used by HNP to assure quality; however, any of the options given in 10CFR50, Appendix B, Criterion VII as implemented by 17.3 may also be used. Evaluation of supplier's QA program will be conducted as determined depending on complexity and end use of item.
2. Section 3.1, Procurement Document Preparation, Review and Control Change: The changed document may not always be as reviewed by the originator; however, at least an equivalent level shall review and approve any changes.
3. Sections 3.2.3, 3.2.4, and 3.2.6 - HNP does not consider that these paragraphs or vendor qualifications apply for the procurement of off-the-shelf items. Off-the-shelf items (which include original as well as spare and replacements) are Commercial Grade Items which are defined in 10CFR 21.

   Special quality verification requirements shall be determined, as necessary, by responsible technical group to assure acceptability of the item. The responsible technical organization will review purchase requisitions of items classified as "commercial grade" to assure proper application of the 10CFR 21 criteria.

Regulatory Guide 1.123, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, (Rev. 1)

HNP shall comply with the requirements of ANSI N45.2.13-1976, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.123 with the following clarifications:

   See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.

4. Section 3.3 requires procurement documents to be reviewed prior to bid or award of contract. The documented review of procurement documents is provided through review of the procurement specification and purchase requisition by the responsible technical organization prior to bid or award of contract.
5. Section 3.4, Procurement Document Control: HNP will meet the requirements of 17.3 in lieu of the requirements specified in this paragraph.
6. Section 4.2, Selection Measures, Outlines certain methods acceptable for the selection of suppliers. HNP's history of using similar methods has proven adequate in the procurement of items; therefore, HNP wishes to replace paragraphs (a), (b), and (c) with the following selection methods:
   1) The supplier's quality assurance capabilities as determined by a direct survey of his facilities and personnel, and the implementation of his quality assurance program.
   2) Evaluating the supplier's history of providing a product which performs satisfactorily in actual use. One or more of the following information shall be evaluated:

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

(i) Experience of users of identical or similar products of the same prospective supplier.

(ii) HNP's records that have been accumulated in connection with previous procurement actions and product operating experience. Historical data should be representative of the supplier's current capability. If there has been no recent experience with the supplier, or if he is a new supplier, the prospective supplier shall be requested to submit information on a similar item or service for evidence of his current capabilities.

(iii) Evaluating the supplier's current quality records supported by documented qualitative and quantitative information which can be objectively evaluated.
This would include review and evaluation of the supplier's quality assurance program manual and procedures, as appropriate, to ensure that the applicable requirements of 10CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants" are met.

(iv) Verification that the supplier holds an active certificate of authorization from the ASME to supply or manufacture materials or the item(s) described in the purchase requisition. A supplier may be considered acceptable, without a survey, to supply off-the-shelf items. An inspection shall be performed to assure that the correct item was received and no damage exists.
Verification that the supplier is listed in the current NUPIC (Nuclear Procurement Issues Committee) database. However, the audit report which formed the basis for listing the supplier in the NUPIC database must be obtained and reviewed for applicability to the procurement. All deficiencies which could degrade the procured item must be resolved prior to the procurement. This review shall be documented and, together with the audit report, be retained.

3) See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.

Regulatory Guide 1.123, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, (Rev. 1)

HNP shall comply with the requirements of ANSI N45.2.13-1976, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.123 with the following clarifications:

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7. Sections 5.2 and 5.3 shall be applied to the extent determined by responsible plant management based on complexity of the item and its end use. It is not intended that these paragraphs be applied to spares or replacement parts that do not change original design intent.
8. Section 6.1, General, Outlines methods for monitoring and evaluating supplier performance. HNP wishes to replace paragraphs (a), (b), (c), (d), and (e) with the following methods for monitoring and evaluating supplier performance:
   A. Reviewing documents generated or processed during activities fulfilling procurement requirements.
   B. Reviewing LER'S.
   C. Periodic audits.
   D. Annual evaluations.
   E. Those controls specified 17.3.
9. Section 6.4, Control of Changes in Items or Services: Since ANSI N45.2 does not apply to the operational phase, equivalent controls outlined in ANSI N18.7-1976 will be used in lieu of the requirements of ANSI N45.2, Section 7.
10. Section 7.4, Measuring and Test Equipment, outlines certain measures to be taken. HNP for the operating phase has addressed the topic of measuring and test equipment in 17.3.2.9 in lieu of the requirements in this paragraph.

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

11. Section 8 provides guidance for purchaser review and disposition of vendor nonconformances. HNP, as purchaser, requires as a minimum deviations to procurement documents and previously approved supplier documents that cannot be brought into conformance prior to shipment of the material to be submitted to dep for approval. Such deviations, when approved by purchaser, are required to be submitted along with shipment of the material. Additionally, Section 8.2, disposition: the third sentence of item b is revised to read:

    Nonconformances to the contractual procurement requirements or purchaser approved documents which consist of one or more of the following shall be submitted to the purchaser for approval of the recommended disposition prior to shipment, when the nonconformance could adversely affect the end use of a *module or shippable component relative to safety, interchangeability, operability, reliability, integrity, or maintainability:

    A. Technical or material requirement is violated;
    B. Requirement in supplier documents, which have been approved by the purchaser, is violated;
    C. Nonconformance cannot be corrected by continuation of the original manufacturing process or by rework; and/or
    D. The item does not conform to the original requirement, even though the item can be restored to a condition such that the capability of the item to function is unimpaired.

        A module is any assembly of interconnected components which constitute an identifiable device, instrument, or piece of equipment. A module can be disconnected, removed as a unit, and replaced with a spare. It has definable performance characteristics which permit it to be tested as a unit. A module could be a card or other subassembly of a larger device, provided it meets the requirements of this definition.

Regulatory Guide 1.123, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, (Rev. 1)

HNP shall comply with the requirements of ANSI N45.2.13-1976, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants, as it is endorsed by Regulatory Guide 1.123 with the following clarifications:

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12. Regulatory Position C.3 indicates that purchaser should verify the implementation of the supplier's corrective action systems when such a system is required, but this verification need not be included as part of the purchaser's corrective action measures.

    HNP interprets this statement to mean that once corrective action has been verified by purchaser on nonconforming vendor items, the items can be released for use in its intended application.

    The cause and action to preclude recurrence of deficiencies is the responsibility of the vendor, and independent verification of such vendor action by purchaser or vendor notification of such action to purchaser, is not required on the basis that the vendor's QA program has been accepted by the purchaser. The QA program provides for determining cause and action to preclude recurrence on significant deficiencies, and purchaser audits are conducted to ensure vendor's compliance with his accepted QA program commitments. In addition, HNP will provide overview of those causes and corrective action activities associated with items of high volume and which are considered significant to safety in cases where vendor's recent performance has appeared marginal.
13. Section 10.2 paragraph a: HNP will comply with this paragraph to the extent that for non-code items, certificates of compliance will be traceable only to the purchase order and not to the specific item.

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants (Rev. 0)

HNP shall comply with requirements of Regulatory Guide 1.144, January 1979, which endorses ANSI N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants, with the following clarifications.

1. C.3.(B)(2): The concepts of when audits are required, i.e., annually, triennially, will be complied with; however, such audits would only be required of the vendor if the vendor is involved with an active contract/procurement document. This concept is as discussed in Sections 3.5.3.1 and 3.5.3.2 of ANSI N45.2.12-1977.
   See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.
2. Section 2.3, Training: The training of HNP audit personnel will be accomplished as described in HNP's position on Regulatory Guide 1.146.
3. Section 2.4, Maintenance of Proficiency: The maintenance of proficiency of HNP audit personnel will be accomplished as described in HNP's position on Regulatory Guide 1.146.
4. Section 3.2.2 indicates that objective evidence is to be examined and evaluated. HNP believes that the use of subjective evidence is also an important element of the audit program. See Section 4.3.2 clarifications below.
5. Section 3.3, Essential Elements of the Audit System; HNP will comply with subsection 3.3.5 as it was originally written (subsection 3.2.5) in ANSI N45.2.12, Draft 3, Revision 4:

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants (Rev. 0)

HNP shall comply with requirements of Regulatory Guide 1.144, January 1979, which endorses ANSI N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants, with the following clarifications.

   "Provisions for reporting on the effectiveness of the quality assurance program to the responsible management." For the audited organization, effectiveness is reported as required in Section 17.3.3.3 and by audit procedures. Other than audit reports, HNP may not directly report on the effectiveness of the quality assurance programs to the audited organization, when such organizations are outside of Duke Energy.
   Subsection 3.3.7 requires verification of effective corrective action on a "timely basis". Timely basis is interpreted to mean within the period of time that is accepted by the organization. Each finding requires a response and a corrective action completion date. These dates are subject to revision and must be escalated to higher authority when there is a disagreement between the audited and the auditing organization on what constitutes "timely corrective action."
6. Section 4.3.1, Preaudit Conference: HNP will comply with the requirement of this paragraph by inserting the word "normally" at the beginning of the first sentence. This clarification is required because, in the case of certain unannounced audits or audits of a particular operation or work activity, a preaudit conference might interfere with the spontaneity of the operation or activity being audited. In other cases, persons who should be present at a preaudit conference may not always be available. Such lack of availability should not be an impediment to beginning an audit. Even in the above examples, which are not intended to be all inclusive, the material set forth in Section 4.3.1 will normally be covered during the course of the audit.
7. Section 4.3.2, Audit/Assessment Process:
   A. Subsection 4.3.2.2 could be interpreted to limit auditors to the review of only objective

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

evidence. Sometimes objective evidence may not be available; therefore, HNP will comply with an alternate sentence which reads: "When available, objective evidence shall be examined for compliance with quality assurance program requirements. If subjective evidence is used (e.g., personnel interviews, direct observations by the auditor), then the audit report or checklist must indicate how the evidence is obtained."

B. Subsection 4.3.2.4 is modified as follows to take into account the fact that some nonconformances are virtually "obvious" with regards to the needed corrective action. As a result of this, HNP proposes the following alternate words: "When a nonconformance or quality assurance program deficiency is identified as a result of an audit, unless the apparent cause, extent, and corrective action is readily evident, further investigations shall be conducted by the audited organization in an effort to identify the cause and effect and to determine the extent of the corrective action required."

C. Subsection 4.3.2.5 contains a statement "acknowledged by a member of the audited organization." This is clarified to mean that "A member of the audited organization has been informed to the findings. Agreement or disagreement with a finding may be expressed in the response from the audited organization."

D. Subsection 4.3.2.6 is modified as follows to account for the fact that immediate notification is not always possible: "Conditions requiring immediate corrective action (i.e., those which are so severe that any delay would be undesirable) shall be reported as immediately as practical to management of the audited organization."

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants (Rev. 0)

HNP shall comply with requirements of Regulatory Guide 1.144, January 1979, which endorses ANSI N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants, with the following clarifications.

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8. Section 4.3.3, Post Audit Conference: HNP will substitute and comply with the following paragraphs: "For all external audits, a postaudit conference shall be held with management of the audited organization to present audit findings and clarify misunderstandings. Where no adverse findings exist, this conference may be waived by management of the audited organization. Such waiver shall be documented in the audit report. For all internal audits unless unusual operating or maintenance conditions preclude attendance by appropriate management, an audit debrief shall be held with management of the audited organization. If there are no adverse findings, management of the audited organization may waive the audit debrief. Such waiver shall be documented in the audit report."
9. Section 4.4, Reporting:
   A. This paragraph requires that the audit report shall be signed by the audit team leader which is not always the most expeditious route for the audit report to be issued as soon as practical. HNP will comply with Section 4.4 as clarified by the following words: "An audit report, which shall be signed by the unit team leader, or his supervisor in the absence of the audit team leader shall provide:" in cases where the audit report is not signed by the lead auditor due to his absence, the record copy of the report must be signed by the lead auditor upon his return. The report shall not require the lead auditor's review/concurrence/signature if the lead auditor is no longer employed by HNP at the time audit report is issued.
   B. HNP will comply with subsection 4.4.3 clarified to read: "Supervisory level personnel with whom significant discussions were held during the course of preaudit (where conducted), audit, and postaudit (where conducted) activities.
   C. Audit reports may not necessarily contain an evaluation statement regarding the effectiveness of the quality assurance program elements which were audited, as required by subsection 4.4.4, but they will provide an effectiveness summary of the

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

audited areas."

D. Section 4.4.6 - Nuclear Oversight section management will determine the need for audit reports to include recommendations for corrective actions.

E. HNP will comply with the last paragraph of Section 4.4 of ANSI N45.2.12 concerning issuing audit reports with the following clarification: "Audit reports shall be issued within thirty working days after the last day of the audit. The last day of an audit shall be considered to be the day of the post-audit conference. If a post-audit conference is not held because it was deemed unnecessary, the last day of the audit shall be considered to be the date the post-audit conference was deemed unnecessary as documented in the audit report."

10. Section 4.5.1, By Audited Organization: HNP will comply with the following clarification of this paragraph:

Regulatory Guide 1.144, Auditing of Quality Assurance Programs for Nuclear Power Plants (Rev. 0)

HNP shall comply with requirements of Regulatory Guide 1.144, January 1979, which endorses ANSI N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants, with the following clarifications.

"Management of the audited organization or activity shall review and investigate all adverse audit findings, as necessary, (cause, etc.) to determine and schedule appropriate corrective action including action to prevent recurrence. They shall respond, in writing, within thirty days after the date of receipt of the audit report. The response shall clearly state the corrective action taken or planned to prevent recurrence and the results of the investigation if conducted. In the event that corrective action is not completed by the time the response is submitted, the audited organization's response shall include a scheduled date for completion of planned corrective action. A follow-up response shall be provided stating the corrective action was completed.

If corrective actions are verified as satisfactorily completed by the quality organization prior to the scheduled completion date or when completion of corrective action can be verified during a follow-up audit, no follow-up response is required. The audited organization shall take appropriate action to assure that corrective action is accomplished as scheduled."

11. Section 5 - audit checklists are not considered QA records. HNP believes that actual audit reports provide sufficient detail to substantiate the results of the audit, and the checklist is maintained as an audit "tool" versus a QA record. Additionally, the audit checklist need only document objective evidence examined to support the audit findings.

Regulatory Guide 1.146, Qualification of QA Program Audit Personnel for Nuclear Power Plants (Rev. 0, 8/80)

HNP shall comply with requirements of Regulatory Guide 1.146, August 1980, which endorses ANSI N45.2.23-1978, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants with the following clarifications.

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1. Section 2.2, Qualification of Auditors: subsection 2.2.1 references an "ANSI B45.2" (presumed to be N45.2); therefore, HNP will comply with an alternate subsection 2.2.1 which reads:
   "Orientation to provide working knowledge and understanding of the HNP QA program, including the ANSI standards and Regulatory Guides included in the program, and Duke Energy's procedures for implementing audits and reporting results."
2. Section 4.1, Organization Responsibility: HNP will comply with this paragraph with the substitution of the following sentence in place of the last sentence in the paragraph.
   "NOS management or the audit team leader shall, prior to commencing the audit, assign

Table B17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

personnel who collectively have experience or training commensurate with the scope, complexity, or special nature of the activities to be audited."

3. Section 5.3, Updating of Lead Auditor's Records: HNP will substitute the following sentence for this paragraph:
   "Records for each lead auditor shall be maintained and updated during the period of the annual management assessment. This annual management assessment shall be as defined in the clarification for Section 3.2 noted above."
4. ANSI N45.2.23, Section 2.3.4 states, "The prospective lead auditor shall have participated in a minimum of five (5) quality assurance audits within a period of time not to exceed three (3) years prior to the date of qualification, one audit of which shall be a nuclear quality assurance audit within the year prior to qualification."

Regulatory Guide 1.146, Qualification of QA Program Audit Personnel for Nuclear Power Plants (Rev. 0, 8/80)

HNP shall comply with requirements of Regulatory Guide 1.146, August 1980, which endorses ANSI N45.2.23-1978, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants with the following clarifications.

HNP substitutes the following instead of the cited sentence of ANSI N45.2.23, Section 2.3.4: "Prospective lead auditors shall demonstrate the ability to effectively implement the audit process and effectively lead an audit team. This process is described in written procedures that provide for evaluation and documentation of the results of this demonstration. In addition, the prospective lead auditor shall have participated in at least two nuclear quality assurance audits within the year preceding the individual's effective date of qualification. Upon successful demonstration of the ability to effectively implement the audit process and effectively lead audits, and having met the other provisions of Section 2.3 of ANSI N45.2.23-1978, the individual may be certified as being qualified to lead audits."

Table B17-2. Site Specific Response to Regulatory Guides and Industry Standards

Table B17-2 identifies additional Regulatory Guides addressing subjects related to implementation of the QAP but the implementation is site specific and controlled with the UFSAR in accordance with 10 CFR 50.59.

Regulatory Guide 1.8, Personnel Selection and Training

Personnel selection and training is site specific.

> Harris addresses conformance with Regulatory Guide 1.8 in UFSAR Chapter 1 Section 8.
>
> A retraining and replacement training program for the unit staff shall be maintained and shall meet or exceed the requirements and recommendations of the September 1979 draft of ANS 3.1, with the exceptions and alternatives noted in Section 1.8 (Personnel Selection and Training) of the FSAR. The initial and requalification training for licensed personnel is through an accredited program based on the systematic approach to training, as allowed by 10 CFR 55.31, 10 CFR 55.59, and Generic Letter 87-07.

Regulatory Guide 1.26, Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants

Quality group classifications and standards trace to the original design and construction of the nuclear power plant and therefore are site specific.

> Harris addresses conformance with Regulatory Guide 1.26 in UFSAR Chapter 1 Section 8.

Regulatory Guide 1.29, Seismic Design Classification

Seismic design classification trace to the original design and construction of the nuclear power plant and therefore is site specific.

> Harris addresses conformance with Regulatory Guide 1.29 in UFSAR Chapter 1 Section 8.

Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel

Nonmetallic thermal insulation for austenitic stainless steel trace to the original design and construction of the nuclear power plant and therefore is site specific.

> Harris addresses conformance with Regulatory Guide 1.36 in UFSAR Chapter 1 Section 8.

Regulatory Guide 1.54, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants

Quality assurance requirements for protective coatings applied to water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Harris addresses conformance with Regulatory Guide 1.54 in UFSAR Chapter 1 Section 8.

Table B17-2. Site Specific Response to Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.143, Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants
Design guidance for radioactive waste management systems, structures, and components installed in light-water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific. Harris addresses conformance with Regulatory Guide 1.143 in UFSAR Chapter 1 Section 8.

Regulatory Guide 1.155, Station Blackout
Addressing Station Blackout is site specific. Harris addresses conformance with Regulatory Guide 1.155 in UFSAR Chapter 1 Section 8.

Regulatory Guide 4.15, Quality Assurance for Radiological Monitoring Programs (Normal Operations) – Effluent Streams and the Environment
Quality assurance for radiological monitoring program (normal operations) – effluent streams and the environment is site specific. Harris does not address conformance to Regulatory Guide 4.15 in UFSAR Chapter 1 Section 8. The radiological monitoring program is addressed in UFSAR Chapter 11.

B17.3.1 MANAGEMENT

B17.3.1.1 Methodology

There are no Harris specific amplifications for this section.

B17.3.1.2 Organization

There are no Harris specific amplifications for this section.

B17.3.1.3 Responsibility

There are no Harris specific amplifications for this section.

B17.3.1.4 Authority

The program and procedures require that the authority and duties of persons and organizations performing activities affecting quality be clearly established and delineated in writing and that these individuals and organizations have sufficient authority and organizational freedom to:

1. Identify quality, nuclear safety, and performance problems.
2. Order unsatisfactory work to be stopped and control further processing, delivery, or installation of nonconforming material.
3. Initiate, recommend, or provide solutions for conditions adverse to quality.
4. Verify implementation of solutions.

B17.3.1.5 Personnel Training and Qualification

There are no Harris specific amplifications for this section.

B17.3.1.6 Corrective Action

The program requires that an evaluation of adverse conditions such as conditions adverse to quality, nonconformances, failures, malfunctions, deficiencies, deviations, and defective material and equipment is conducted to determine need for corrective action. Conditions adverse to quality are identified through inspections, assessments, tests, checks, and review of documents.

The program requires corrective action to be initiated to preclude recurrence of significant conditions adverse to quality.

For significant conditions adverse to quality, procedures require follow-up reviews, verifications, inspections, etc., to be conducted to verify proper implementation of corrective action and to close out the corrective action documentation.

The program outlines the methodology for resolution of disputes involving quality and nuclear safety issues arising from a difference of opinion between identifying personnel and other groups.

Significant conditions adverse to quality are reported to appropriate management for review and evaluation.

Periodic review and evaluation of adverse trends are performed by management.

B17.3.1.7 Regulatory Commitments

There are no Harris specific amplifications for this section.

B17.3.2 PERFORMANCE/VERIFICATION

B17.3.2.1 Methodology

There are no Harris specific amplifications for this section.

B17.3.2.2 Design Control

Controls are applied to the development, content and use of computer codes to ensure (1) the codes are developed, documented, verified and certified for use per approved procedures; (2) the codes are properly controlled to preclude use of outdated or obsolete codes; (3) that proper instructions concerning the use of the codes are provided; and (4) adequate QA provisions are implemented for the procurement of computer codes.

B17.3.2.3 Design Verification

There are no Harris specific amplifications for this section.

B17.3.2.4 Procurement Control

Potential contractors and suppliers are evaluated prior to award of a procurement contract when needed to assure the contractor's or supplier's capability to comply with applicable technical and quality requirements.

Procurement documents, such as purchase specifications, contain or reference the following:

1. Technical, administrative, regulatory, and reporting requirements, including material and component identification requirements, drawings, specifications, codes and industrial standards, test and inspection requirements, and special process instructions.
2. Identification of the documentation to be prepared, maintained, or submitted (as applicable) to HNP for review and approval. These documents may include, as necessary, inspection and test records, qualification records, or code required documentation.
3. Identification of those records to be retained, controlled, and maintained by the supplier, and those delivered to the purchaser prior to use or installation of the hardware.

Procurement documents require suppliers to operate in accordance with QA programs which are compatible with the applicable requirements of the HNP QA Program and procedures where their services are utilized in support of plant activities.

B17.3.2.5 Procurement Verification

There are no Harris specific amplifications for this section.

B17.3.2.6 Identification and Control of Items

Procedures require that materials, parts, and components be identified and controlled to prevent the use of incorrect or defective items.

These procedures also require that identification of items be maintained either on the item in a manner that does not affect the function or quality of the item, or on records traceable to the item.

Procedures implementing these requirements provide for the following:

1. Verification that items received at the plant are properly identified and can be traced to the appropriate documentation, such as drawings, specifications, purchase orders, manufacturing and inspection documents, nonconformance reports, or material test reports.
2. Verification of item identification consistent with the HNP inventory control system and traceable to documentation which identifies the proper uses or applications of the item.
3. Verification of correct identification of material, parts and components prior to fabrication, assembly installation or use, and results documented.

B17.3.2.7 Handling, Storage, and Shipping

Provisions are established to control the shelf life and storage of chemicals, reagents, lubricants, and other consumable materials.

B17.3.2.8 Test Control

Test procedures incorporate or reference the following, as required:

1. Instructions and prerequisites for performing the test.
2. Use of proper test equipment.
3. Mandatory inspection hold points.
4. Acceptance criteria.

Test results are documented, evaluated, and their acceptability determined by a qualified, responsible individual or group.

When the acceptance criteria is not met, affected areas are to be retested or evaluated, as appropriate.

B17.3.2.9 Measuring and Test Equipment Control

Portable measuring and test equipment is calibrated by standards which are at least four times as accurate as the portable measuring and test equipment, unless limited by the state of the art. In cases where the accuracy is not achievable or is limited by the state of the art, an engineering evaluation or other appropriate justification is performed and documented to justify acceptability of the M&TE in question. The evaluation is reviewed in accordance with approved procedures.

Calibration of installed plant devices shall be against M&TE having sufficient accuracy, greater than the device being calibrated, to assure that the system containing the device is within the specified system tolerance. The basis for determining the "greater than accuracy" shall be documented.

Reference and transfer standards are traceable to nationally recognized standards; or where national standards do not exist, provisions are established to document the basis for the calibration.

B17.3.2.10 Inspection, Test, and Operating Status

These procedures include the application, removal, and verification of inspection and welding stamps, or other status indicators as appropriate.

Altering the sequence of required tests, inspections, and other operations important to safety can only be accomplished by methods outlined in procedures.

B17.3.2.11 Special Process Control

There are no Harris specific amplifications for this section.

B17.3.2.12 Inspection

There are no Harris specific amplifications for this section.

B17.3.2.13 Corrective Action

The primary goal of the corrective action program is to improve overall plant operations and performance by identifying and correcting root causes of equipment and human performance problems.

Procedures define requirements for a corrective action program that charges personnel working at or supporting the nuclear plants with the responsibility to identify adverse conditions (including conditions adverse to quality).

Procedures include requirements for verification of the acceptability of the rework/repair of items by reinspection and/or testing in accordance with the original inspection or test requirements or by an accepted alternative inspection and testing method.

Conditions that require rework/repairs are identified through the use of maintenance work request forms.

B17.3.2.14 Control of Documents

Changes to documents are reviewed and approved by the same organization that performed the original review and approval or by other designated qualified responsible organizations.

B17.3.2.15 Records

The structure in which single copy records are maintained is designed to prevent destruction, deterioration, or theft. This structure ensures protection against destruction by fire, flooding, theft, and deterioration by the environmental conditions of temperature and humidity.

B17.3.3 ASSESSMENT

B17.3.3.1 Methodology

There are no Harris specific amplifications for this section.

B17.3.3.2 Independent Review

There are no Harris specific amplifications for this section.

B17.3.3.3 Independent Assessment

There are no Harris specific amplifications for this section.

B17.3.3.3.1 Organization

There are no Harris specific amplifications for this section.

B17.3.3.3.2 Internal Assessment Process

There are no Harris specific amplifications for this section.

B17.3.3.3.3. Internal Audit Program

B17.3.3.3.3.1 Other Reviews Prescribed by the Code of Federal Regulations

There are no Harris specific amplifications for this section.

B17.3.3.3.3.2 Independent Audit of Fire Protection Program

There are no Harris specific amplifications for this section.

B17.3.3.3.4 Results

There are no Harris specific amplifications for this section.

B17.3.3.3.5 Supplier Oversight

There are no Harris specific amplifications for this section.

B17.3.3.3.6 Independent Audit of QA Functions

There are no Harris specific amplifications for this section.

B17.3.3.3.7 Audit Frequency Extensions

There are no Harris specific amplifications for this section.

B17.3.4 ADMINISTRATIVE CONTROLS

This section was added to the HNP UFSAR description of the QA Program to relocate certain administrative controls from HNP Technical Specifications. Those relocated administrative controls, indicated by section heading, are either contained below or referenced to the current location.

Review and Audit

B17.3.4.1 10CFR50.59 and technical reviews

See Sections 17.3.4.1, Technical Review and 17.3.4.2, 10 CFR 50.59 Reviews.

B17.3.4.2 Plant Nuclear Safety Committee (PNSC)

See Section 17.3.3.2, Independent Review.

B17.3.4.3 HNP Independent Review Program

See Section 17.3.3.2, Independent Review.

B17.3.4.4 Independent Safety Engineering Group

B17.3.4.4.1 Organization

The Independent Safety Engineering Group (ISEG) functions of improving licensee safety performance and ability to respond to accidents by providing onsite technical support and continuous evaluation and feedback of lessons learned from operating experience are performed by a combination of different groups through the performance of their normal activities.

B17.3.4.4.2 Activities

Key ISEG activities are outlined below with the groups that currently perform these activities:

1. Examination of Unit Operating Characteristics:
    - HNP has an established Corrective Action Program that includes processes for the identification, classification, trending and correcting of conditions adverse to quality.
    - NOS performs independent monitoring and audit of activities as defined in Section 17.3.3.3.
    - HNP has implemented a Maintenance Rule Program that provides reasonable assurance that structures, systems, trains, and components are capable of fulfilling their intended safety significant functions.
    - Harris Engineering Section has implemented a program that provides for the systematic trending of system and component performance to determine the effectiveness of system/component maintenance
    - A corporate Probabilistic Safety Assessment Unit has been established with the mission of maintaining and updating plant specific risk models and risk based tools that are used to provide risk insights and tools to: support on-line maintenance and outage risk assessments; support the Maintenance Rule Program; evaluate proposed plant changes for risk impact; monitor the risk effectiveness of plant on-line maintenance activities; and support other regulatory activities.
2. Examination of NRC Issuances, Industry Advisories, and Licensee Event Reports and other Sources of Unit Design Information which May Indicate Areas of Improving Unit Safety:
    - Duke Energy has implemented an Operating Experience (OE) Program that provides for the receipt, processing, status reporting, screening, reviewing, evaluating, and taking preventive/corrective actions in response to OE information.
    - The Nuclear Oversight organization independently evaluates the use of OE in the conduct of audits.
    - The On-Site Review Committee reviews License Event Reports developed pursuant to 10CFR50.73 as part of the Independent Review in Section 17.3.3.2.
3. Review of Plant Operations, Modifications, Maintenance, and Surveillances to Verify Independently that these Activities are Performed Safely and Correctly and that Human Errors are Reduced as Much as Practical:
    - NOS audits in Section 17.3.3.3 and the Independent Review Program in Section 17.3.3.2accomplish this function.

B17.3.4.5 Outside agency inspection and audit program

See Section 17.3.3.3.3.2, Independent Audit of Fire Protection Program.

B17.3.4.6 Procedure Review Requirements

See Section 17.3.2.14 for required reviews for changes to procedures, tests, and experiments.

B17.3.4.7 Record Retention

A list of typical operational phase QA Records is included in Section 17.3.2.15.

Attachment C, Robinson Specific QAPD

Robinson has received NRC approval to implement 10 CFR 50.69, Risk-informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors. SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of the QAPD as they are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule.

10CFR 50.69, provides alternative approaches for establishing the requirements for treatment of SSCs using a risk informed method of categorization according to safety significance. As part of implementing 10 CFR 50.69, engineering will establish a collection of program elements to monitor and / or maintain SSC critical attributes ensuring reasonable confidence continued capability and reliability of the design basis functions. These elements include, inspection and testing, corrective actions, feedback and process adjustments, performance monitoring, program documentation, and reporting, as applicable to meet 10CFR 50.69(d), (e), (f), and (g). DEC implements the requirements of the QAPD commensurate with the safety classification of the SSCs, as described in applicable licensing and design documents, and implementing procedures.

Information presented in this attachment is specific to Robinson and was contained in the UFSAR prior to Amendment 41.

Where a section contains no descriptive information beyond that in the generic text in the body of the document, a statement is made to that effect and no content is included. See C17.3.1.2, Organization for example.

C17. QUALITY ASSURANCE

C17.1 QA DURING DESIGN AND CONSTRUCTION

See Robinson UFSAR Chapter 17 for historic information from the description of the QA Program for design and construction.

C17.2 OPERATIONAL QA

Deleted

(NOTE: In April 1995, NRC approved the reformatting of the description of the Robinson QA Program to follow Standard Revision Plan Section 17.3, replacing the content of 17.2.)

C17.3 QUALITY ASSURANCE PROGRAM (QAP) DESCRIPTION

INTRODUCTION

This content is not addressed in SRP Section 17.3; therefore, the Robinson description of the QA Program did not include this section.

DEFINITIONS

There are no Robinson specific definitions.

EXPLANATION OF "QUALITY ASSURANCE"

There is no Robinson specific content.

QA STANDARDS AND GUIDES

Table C17-1 and C17-2 address QAP conformance to the referenced regulatory and program guidance in NUREG-0800 Section 17.3.

The content of Table C17-1 was transferred from Section 1.8 of the Robinson UFSAR. Changes to the content of Table C17-1 are controlled in accordance with 10 CFR 50.54(a). Subsequent changes to the QAP are incorporated in this document as identified in Section 17.3.1.7.

Table C17-2 addresses additional Regulatory Guides that relate to implementation of the QAP but the implementation is site specific and controlled with the Robinson UFSAR in accordance with 10 CFR 50.59.

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards

Generic Exception:

Table C17-1 addresses the Robinson Nuclear Plant (RNP) conformance of the Quality Assurance Program to certain NRC Regulatory Guides. In so doing, specific editions of industry standards are identified for compliance with exceptions and alternatives. Those identified standards include references to other industry standards for activities including, but not limited to; design, fabrication, inspection, and testing. Those included reference industry standards are considered to be guidance documents for details of how activities may be accomplished. The actual standard to be used in such cases is controlled by each station's current licensing and design bases.

The content of Table C17-1 was transferred from H. B. Robinson (RNP) UFSAR Section 1.8. As identified therein, Regulatory Guides (originally called Safety Guides) have been published beginning in late 1970. Since RNP was licensed for operation prior to that time, they were not addressed. Applicable QA Regulatory Guides which have been addressed during the operating phase are discussed below.

Regulatory Guide 1.28, Quality Assurance Program Requirements (Design and Construction) (Rev. 0)
ANSI Standard N45.2-1971, Quality Assurance Requirements for Nuclear Power Plants
This guide and the standard it endorses have been superseded for operations activities by Regulatory Guide 1.33 and ANSI N18.7-1976 which it endorses. The Operational Quality Assurance Program complies with Regulatory Guide 1.33 and ANSI N18.7-1976 as stipulated in Appendix A to that program; therefore, Regulatory Guide 1.28 (Safety Guide 28) and ANSI N45.2-1971 which it endorses are not considered necessary and are not included as part of the program.

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment (Revision 0) (August, 1972)
ANSI standard N45.2.4-1972, (IEEE-336-1971), Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations
RNP shall comply with the provisions of Regulatory Guide 1.30, August 1972 and ANSI N45.2.4-1972 with the following exceptions:
The installation, inspection, and testing of nuclear power plant instrumentation and electrical equipment at RNP will be in accordance with the applicable requirements of ANSI N45.2.4-1972 with the following exceptions:
a) Section 1.4 titled <u>Definitions:</u> Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in RNP's commitment to Regulatory Guide 1.74. b) Section 1.5 titled <u>Referenced Documents:</u> RNP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.30, Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment (Revision 0) (August, 1972)
ANSI standard N45.2.4-1972, (IEEE-336-1971), Installation, Inspection, and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations
RNP shall comply with the provisions of Regulatory Guide 1.30, August 1972 and ANSI N45.2.4-1972 with the following exceptions:

c) Section 2.5 titled Measuring and Test Equipment: RNP will implement the applicable portions of this Section as follows:
The status of portable items of measuring and test equipment and reference standard shall be identified by use of tags, stickers, labels, routing cards, computer programs, or other suitable means for the date recalibration is due or the frequency of recalibration. These items are in a calibration program which requires recalibration on a specified frequency or, in certain cases, prior to use.
Instrumentation and electrical equipment in the categories listed below shall be in a calibration program. This program provides, by the use of status cards, computer schedules, or tags, for the date that recalibration is due and indicates the status of calibration. The identity of person(s), performing calibration is provided on the calibration documents.
   1) Instruments installed as listed in the RNP Technical Specifications
   2) Installed instrumentation used to verify RNP Technical Specification parameters, and
   3) Installed safety-related instruments and electrical equipment that provide an active function during operation or during shutdown; i.e., not a device being designated safety-related solely because the instrument is an integral part of a pressure retaining boundary.

d) Section 7 titled Data Analysis and Evaluation states in part, "Procedures shall be established for processing inspection and test data and their analysis and evaluation." At RNP, data processing procedures per se have not been developed; instead, test data are recorded, processed, and analyzed in accordance with procedures and instructions in appropriate functional areas; e.g., maintenance, startup.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation) Revision 2, February 1978
ANSI Standard N18.7-1976, Administrative Controls and Quality Assurance Requirements for the Operational Phase of Nuclear Power Plants
Comply with the provisions of Regulatory Guide 1.33, Rev. 2 February 1978, and the requirements and recommendations for administrative controls described in ANSI N18.7-1976, except as stated below:

1. Section 1 “Scope,” recommends that this standard applies to activities other than those associated with safety related equipment, activities, and procedures. SSCs categorized as Low Safety Significant in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule. As such, the scope of activities can be adjusted in station procedures as allowed by the rule. Procedures provide guidance for specific process changes as part of 10 CFR 50.69 implementation.
2. Exception to Paragraph C.3 of Regulatory Guide 1.33 and ANSI N18.7-1976 Section 4.3: Independent Review Program requirements are replaced by Section 17.3.3.2, Independent Review. This exception uses NRC Safety Evaluation dated January 13, 2005 to Nuclear Management Company (ADAMS ML050210276).
3. In lieu of the audit program provisions contained in Regulatory Position C.4 of Regulatory

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Guide 1.33, audits of facility activities will be conducted in accordance with Section 17.3.3.3.3.

4. Section 4.5 - Written audit reports are not formally reviewed as part of the Independent Review function.
5. Section 4.5 - The CNO will assure that an independent assessment of the overall Nuclear Oversight program is conducted at least once every 24 months. See Section 17.3.3.3.6 Independent Audit of QA Functions.

Regulatory Guide 1.33, Quality Assurance Program Requirements (Operation) Revision 2, February 1978

ANSI Standard N18.7-1976, Administrative Controls and Quality Assurance Requirements for the Operational Phase of Nuclear Power Plants

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Comply with the provisions of Regulatory Guide 1.33, Rev. 2 February 1978, and the requirements and recommendations for administrative controls described in ANSI N18.7-1976, except as stated below:

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6. Section 4.5, Audit Program- ANSI N18.7-1976/ANS-3.2, Section 4.5 is implemented with the following clarification: The audits of selected aspects of operational phase activities as identified in Section 17.3.3.3.3, Internal Audit Program, are scheduled based on plant performance and importance to safety but at a frequency not to exceed twenty-four months with extensions as allowed in Section 17.3.3.3.7, Audit Frequency Extensions.
7. Section 5.2.16 titled <u>Measuring and Test Equipment:</u> See Section 17.3.2.9 for clarification.
8. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Rev. 2, February 1978, shall be established, implemented, and maintained as specified in the RNP Technical Specifications.
9. Section 5.2.17 titled <u>Inspections:</u> The second to the last sentence in the last paragraph, "Deviations, their cause, and any," to be consistent with Section 5.2.11 and 10CFR50, Appendix B, the cause of the deviation will be determined for only significant conditions adverse to safety.
10. Section 5.3.9.1 titled <u>Emergency Procedure Format and Content:</u> Emergency procedures shall be in the format as committed to in NUREG-0737, TMI Action Plan.
11. Section 5.2.2 titled <u>Procedure Adherence:</u> Temporary changes to approved procedures, tests, or experiments may be approved by two members of the plant staff, at least one of whom holds a Senior Reactor Operator License if such change does not change the intent of the original procedure, test, or experiment. Temporary changes shall be documented and approved as a permanent change or deleted within 21 days of receiving temporary approval.
12. Section 5.2.15 titled <u>Review, Approval and Control of Procedures,</u> states that, "Plant procedures shall be reviewed by an individual knowledgeable in the area affected by the procedure no less frequently than every two years to determine if changes are necessary. A revision to a procedure constitutes a procedure review." In lieu of this commitment, Duke Energy addresses programmatic controls in Section 17.3.2.14 to continually identify procedure revisions which may be needed to ensure that procedures are appropriate for the circumstance and are maintained current.
13. Section 5.2.13.1, Procurement Document Control: When purchasing commercial-grade calibration services from certain accredited calibration laboratories, the procurement documents are not required to impose a quality assurance program consistent with ANSI N45.2-1971. Alternate requirements described in Tables 17-1 and C17-1 for Regulatory Guide 1.123 may be implemented in lieu of imposing a quality assurance program consistent with ANSI N45.2-1971. When purchasing nuclear safety related material, equipment and services, the supplier is required to the meet applicable criteria of 10 CFR 50, Appendix B and 10 CFR 21– with the exception that SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document. These 50.69 LSS

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

SSCs are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule. Procedures provide guidance for specific process changes as part of 10 CFR 50.69 implementation.

Regulatory Guide 1.37, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.1-1973, Cleaning of Fluid Systems and Associated Components During Construction Phase of Nuclear Power Plants

Those areas of the QA Program applicable to onsite cleaning of materials and components, cleanliness control, and pre-operation cleaning and layup of RNP fluid systems, will be in accordance with ANSI N45.2.1-1973, with the following exceptions:

a) At RNP a classification system similar to ANSI N45.2.1-1973 has been developed and is fully implemented for cleaning of fluid systems.
b) Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in RNP commitment to Regulatory Guide 1.74.
c) Section 1.5 titled Referenced Documents: RNP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants

Packaging, shipping, receiving, storage, and handling of RNP items are in accordance with applicable requirements of ANSI N45.2.2-1972 with the following specific exceptions:

a) Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in RNP commitment to Regulatory Guide 1.74.
b) Section 1.5 titled Referenced Documents: RNP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.
c) Section 2.7 titled Classification of Items and Section 6.1.2 titled Levels of Storage:
    1) Special electronic equipment and instrumentation received as assembled panels will be stored as recommended by the manufacturer and/or based on engineering evaluation to prevent damage, deterioration, or contamination, but not necessarily in a Level A storage area.
    2) Chemicals used at RNP are stored at the point of use and/or in warehouse areas that satisfy the requirement of Level B storage. These storage areas have been evaluated and determined to be adequate for the limitations established by the manufacturer.
    3) Special nuclear materials are stored in areas specifically designed for such storage.
d) Section 7.3.4 - RNP intends to comply with the requirements of this section with the following clarification: Test loads equal to or greater than the original crane rating shall not pass over locations where special nuclear material is stored or where reactor system components or high cost equipment are located.
e) Section 6.4.2 of ANSI N45.2.2 - 1972, titled Care, sub-items (5), (6), and (7) are clarified as follows:
    1) Sub-item (5), space heaters in electrical equipment shall be energized, unless a documented engineering evaluation determines that such space heaters are not required.
    2) Sub-item (6). large rotating electrical equipment (i.e. greater than or equal to 50 horsepower) shall be given insulation resistance tests on a scheduled basis, unless a

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

documented engineering evaluation determines such tests are not needed.

Regulatory Guide 1.38, Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.2-1972, Packing, Shipping, Receiving, Storage, and Handling of Items for Nuclear Power Plants

Packaging, shipping, receiving, storage, and handling of RNP items are in accordance with applicable requirements of ANSI N45.2.2-1972 with the following specific exceptions:

3) Sub-item (7). prior to being placed in storage, rotating equipment weighing over approximately 50 lbs. shall be evaluated and documented by engineering personnel to determine if shaft rotation during storage is required. If rotation is required the degree of turn shall be such that the parts receive lubrication where applicable and the shaft does not come to rest in a previous position. Required rotation shall be performed at the necessary intervals and documented.

f) Section 6.2.4 of ANSI N45.2.2 - 1972, titled Storage of Food and Associated Items. The sentence is replaced with the following: "The use or storage of food, drinks, and salt tablet dispensers in any storage area shall be controlled and shall be limited to designated areas where such use or storage is not deleterious to stored items."

Regulatory Guide 1.39, Housekeeping Requirements for Water- Cooled Nuclear Power Plants (March 1973)

ANSI Standard N45.2.3-1973, Housekeeping, During the Construction Phase of Nuclear Power Plants

The applicable requirements of ANSI N45.2.3-1973 are followed at RNP within the context of the established QA Program with the following specific exception -- the zone designations of Section 2.1 of ANSI N45.2.3 and the requirements associated with each zone are considered impractical for implementation, as stated, during the operations phase. Instead, procedures or instruction for housekeeping activities, which include the applicable requirements outlined in Section 2.1 of ANSI N45.2.3 and which take into account radiation control considerations, security considerations, and cleanliness requirements are developed on a case basis for work to be performed.

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination, and Testing Personnel (September, 1980)

ANSI Standard N45.2.6-1978, Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants

RNP shall comply with NRC Regulatory Guide 1.58, September 1980 which endorses ANSI N45.2.6-1978, with the following exceptions:

1. Section 1.2 titled <u>Applicability:</u> RNP elects not to apply the requirements of this guide to those personnel who are involved in the daily operations of surveillance, maintenance, and certain technical and support services whose qualifications are controlled by the RNP Technical Specifications or are controlled by other QA Program commitment requirements. Only personnel in the following listed categories will be required to meet ANSI N45.2.6-1978 requirements:
   a. Nondestructive examination (NDE) personnel
   b. QC inspection personnel
   c. Receipt inspection personnel

Regulatory Guide 1.58, Qualification of Nuclear Power Plant Inspection, Examination, and

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)
Testing Personnel (September, 1980)

ANSI Standard N45.2.6-1978, Qualification of Inspection, Examination, and Testing Personnel for Nuclear Power Plants

RNP shall comply with NRC Regulatory Guide 1.58, September 1980 which endorses ANSI N45.2.6-1978, with the following exceptions:

2. The fourth paragraph of Section 1.2 requires that the Standard be imposed on personnel other than RNP employees. The applicability of the Standard to suppliers and contractors will be documented and applied, as appropriate, in the procurement documents for such suppliers and contractors or in interface agreements for Duke Energy non-nuclear organizations providing services identified in Section 17.3.1.2.3.
3. Section 1.4 titled <u>Definitions:</u> Definitions in this Standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in RNP commitment to Regulatory Guide 1.74.
4. Section 2.5 titled <u>Physical:</u> RNP will implement the requirements of this Section with the stipulation that, where no special physical characteristics are required, none will be specified. The converse is also true: if no special physical requirements are stipulated by RNP, none are considered necessary. RNP employees receive an initial physical examination to assure satisfactory physical condition; however, only the following listed personnel will receive an annual (± 2 months) examination:
   a. NDE personnel
   b. QC inspection personnel
   c. Receipt inspection personnel

   This annual examination shall consist of the near visual acuity using the standard Jaeger's type chart or equivalent test.
5. Section 3 titled <u>Qualifications:</u> Only personnel performing NDE (such as LP, MT, UT, & RT) are required to be grouped in levels of capability and certified as such. Personnel performing inspection will be certified for inspection, review and evaluation of inspection data, and reporting of inspection and test results.
6. Section 3.5 titled <u>Education & Experience Recommendations:</u> RNP will certify individual inspectors through training and experience to requirements appropriate to the specific assignment; however, except for NDE, personnel are not required to be classified by levels of capability. Inspection personnel may be qualified based on pre-established experience, education, on-the-job training, written examinations and proficiency tests associated with the specific activity. Proficiency tests are given to personnel performing independent QC inspections and documented acceptance criteria are developed to determine if individuals are properly trained and qualified. Certificates of qualification delineate the functions personnel are qualified to perform. Qualification records are maintained and performance evaluations conducted at least once every three years. If organizations elect to utilize qualifications by levels for non-NDE inspections, Level I inspectors receive a minimum of 4 months experience as Level I before being certified as Level II, in lieu of one year experience recommended by ANSI N45.2.6 Section 3.5.2(1). Organizations identify in their procedures if they qualify their inspectors by Level or by task qualifications. Inspectors are only assigned functions for which they have been qualified.

Regulatory Guide 1.64, Quality Assurance Requirements for the Design of Nuclear Power Plants (October 1973)

ANSI Standard N45.2.11-1974, Quality Assurance Requirements for the Design of Nuclear Power Plants

Those areas of the QA Program for RNP applicable to design or modification of the plant are in accordance with the applicable guidance of ANSI N45.2.11-1974, with the following exception:

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

a) Section 1.4 titled Definitions: Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in RNP commitment to Regulatory Guide 1.74.

Regulatory Guide 1.74, Quality Assurance Terms and Definitions (February, 1974)
ANSI Standard N45.2.10-1973, Quality Assurance Terms and Definitions
The quality assurance terms and definitions of ANSI N45.2.10-1973 and Regulatory Guide 1.74 are being complied with for use in describing and implementing the RNP QA Program.

Regulatory Guide 1.88 , Requirements for Collection, Storage, and Maintenance of Quality Assurance Records for Nuclear Power Plants
ANSI Standard N45.2.9-1979 , "Requirements for Collection, Storage, and Maintenance of Quality Assurance Records for Nuclear Power Plants"
As documented in RNP Letter to the NRC dated March 23, 1993, RNP is no longer committed to Regulatory Guide 1.88 "Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records," August 1974.

See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.

The requirements for collection, storage, and maintenance of QA records at RNP will be in accordance with ANSI N45.2.9-1979 and Section 17.3.2.15, subject to the following:

1. Section 1.5 titled Referenced Documents: RNP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.
2. Section 5.4 Item 2 "Records shall be firmly attached in binders or placed in folders or envelopes for storage in steel file cabinets or on shelving in containers." RNP complies with this requirement except for periods when records are in the receipt process.
3. Section 5.6 states: "Records shall be stored in facilities constructed and maintained in a manner which minimizes the risk of damage or destruction from the following:
   a. Natural disasters such as winds, floods, or fires.
   b. Environmental conditions such as high and low temperatures and humidity.
   c. Infestation of insects, mold, or rodents."

   Records are stored in permanent and temporary facilities as follows:
   1) One hour UL-rated fireproof file cabinets are utilized for temporary storage of hardcopy records. These file cabinets are located at work locations throughout the plant and will contain the records until the records are transmitted to the appropriate Document Control Center.
      Records being processed in Document Control Centers will be stored in fireproof cabinets when they are not being processed and until they are sent to the vault. In addition, records that are generated and authenticated electronically are afforded protection as described in N45.2.9-1979 prior to conversion to permanent storage media.

Regulatory Guide 1.88 , Requirements for Collection, Storage, and Maintenance of Quality Assurance Records for Nuclear Power Plants
ANSI Standard N45.2.9-1979 , "Requirements for Collection, Storage, and Maintenance of Quality Assurance Records for Nuclear Power Plants"
As documented in RNP Letter to the NRC dated March 23, 1993, RNP is no longer committed to Regulatory Guide 1.88 "Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records," August 1974.

   2) Permanent storage of QA records will be in the plant vault constructed to meet the

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

requirements of this ANSI standard, and via electronic means which also meet applicable provisions of this standard, in addition to those delineated below.

3) Selected records may be stored off-site by a QA Records Storage supplier provided that supplier meets the applicable sections of this ANSI standard.

4. Section 6.2 states: "Storage systems shall provide for retrieval of information in accordance with planned retrieval times based upon the record type." Retrieval of records at RNP is via a random access computer system using key words and document identification numbers, or through a manual index for records completed prior to 1982. The manual system is keyed to Plant Systems.
5. Section 7.3.3 states: "Various regulatory agencies have requirements concerning records that are within the scope of this Standard. The most stringent requirements shall be used in determining the retention period."
6. RNP will continue to adhere to the recommendations of Appendix A of ANSI N45.2.9-1974, or with the most stringent requirement with respect to records retention.

Regulatory Guide 1.94, Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants (April 1976)
ANSI Standard N45.2.5-1974, Supplementary Quality Assurance Requirements for Installation, Inspections, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants
The original specification requirements, applicable guidance contained in Regulatory Guide 1.94, or acceptable alternatives based on an engineering evaluation will be utilized in the event future structural work is to be performed which falls under the established requirements of the RNP QA Program. Future field production welding acceptance criteria will be based on NCIG-01, "Visual Weld Acceptance Criteria for Structural Welding at Nuclear Power Plants," Revision 2, dated May 7, 1985, Prepared by the Nuclear Construction Issues Group (NCIG) for structural safety-related and non-safety related pipe, conduit, cable tray, duct, and equipment supports where welding is specified to be in accordance with AWSD1.1. This will be implemented through appropriate RNP specifications.

Regulatory Guide 1.116, QA Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems (June, 1976)
ANSI Standard N45.2.8-1975, Supplementary Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems for the Construction Phase of Nuclear Power Plants
Regulatory Guide 1.116, June, 1976, endorses ANSI N45.2.8-1975. RNP does not commit to Regulatory Guide 1.116 but does endorse parts of ANSI N45.2.8-1975 as described below.
Within the context of the established QA Program, the applicable guidance contained in ANSI N45.2.8-1975 will be utilized in relation to mechanical maintenance or modification with the following exceptions:

a) Section 1.4 titled <u>Definitions:</u> Definitions in this standard which are not included in ANSI N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in RNP commitment to Regulatory Guide 1.74.
b) Section 1.5 titled <u>Referenced Documents:</u> RNP's commitment to other documents referenced in this standard shall be as stated in our commitment to that document.
c) Section 2.8 titled <u>Measuring and Test Equipment:</u> RNP will implement the applicable portions of this section as follows:
   The status of portable items of measuring and test equipment and reference standards shall

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

be identified by use of tags, stickers, labels, routing cards, computer programs, or other suitable means for the date recalibration is due or the frequency of recalibration. These items are in a calibration program which requires recalibration on a specified frequency or, in certain cases, prior to use.

Instrumentation and electrical equipment in the categories listed below shall be in a calibration program. This program provides, by the use of status cards, computer schedules, or tags, for the date that recalibration is due and indicates the status of calibration. The identity of person(s) performing the calibration is provided on the calibration documents.

1) Instruments installed as listed in the RNP Technical Specifications,
2) Installed instrumentation used to verify RNP Technical Specification parameters, and
3) Installed safety-related instruments and electrical equipment that provide an active function during operation or during shutdown; i.e., not a device being designated safety-related solely because the instrument is an integral part of a pressure retaining boundary.

d) Section 6 titled Data Analysis and Evaluation states in part, "Procedures shall be established for processing inspection and test data and their analysis and evaluation." RNP data processing procedures per se have not been developed; instead, test data are recorded, processed, and analyzed in accordance with procedures and instructions in appropriate functional areas; e.g., maintenance, startup.

Regulatory Guide 1.123, Quality Assurance Requirements for Control or Procurement of Items and Services for Nuclear Power Plants (July, 1977)
ANSI Standard N45.2.13, Quality Assurance Requirements for (Draft 2, Rev. 4, April, 1974) Control or Procurement of Items and Services for Nuclear Power Plants
RNP does not commit to Regulatory Guide 1.123; however, the applicable guidance contained in ANSI N45.2.13-1974, Draft 2, Rev. 4, and ANSI N18.7-1976 will be utilized in relation to procurement of items and services performed under the established requirements of the RNP QA Program.
See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.

Regulatory Guide 1.144, Auditing of Quality Assurance (January 1979)
ANSI Standard N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants
RNP will follow the requirements and recommendations of Regulatory Guide 1.144 and ANSI N45.2.12 with the following clarifications:

1. RNP will follow the requirements and recommendations of Regulatory Guide 1.144 paragraphs C.1, C.2, C.3.a.2, C.3.b, and C.4. Our position on paragraph C.3.a.1 is as follows:

   Audits of operational phase activities, as outlined in Section 17.3.3.3.3, shall be performed at the frequencies specified therein.

   See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.
2. RNP will comply with the last paragraph of Section 4.4 of ANSI N45.2.12 concerning issuing audit reports with the following clarification: "Audit reports shall be issued within thirty working days after the last day of the audit. The last day of an audit shall be considered to be the day of the post-audit conference. If a post-audit conference is not held because it was deemed unnecessary, the last day of the audit shall be considered to be the date the

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

post-audit conference was deemed unnecessary as documented in the audit report."

3. ANSI N45.2.12 Section 4.3. 1, Preaudit Conference: RNP will comply with the requirement of this paragraph by inserting the word "Normally" at the beginning of the first sentence. This clarification is required because, in the case of certain unannounced audits or audits of a particular operation or work activity, a preaudit conference might interfere with the spontaneity of the operation or activity being audited. In other cases, persons who should be present at a preaudit conference may not always be available. Such lack of availability should not be an impediment to beginning an audit. Even in the above examples, which are not intended to be all inclusive, the material set forth in Section 4.3.1 will normally be covered during the course of the audit.

Regulatory Guide 1.144, Auditing of Quality Assurance (January 1979)
ANSI Standard N45.2.12-1977, Requirements for Auditing of Quality Assurance Programs for Nuclear Power Plants
RNP will follow the requirements and recommendations of Regulatory Guide 1.144 and ANSI N45.2.12 with the following clarifications:

4. ANSI N45.2.12 Section 4.3.3, Post Audit Conference: RNP will substitute and comply with the following paragraphs: "For all external audits, a post audit conference shall be held with management of the audited organization to present audit findings and clarify misunderstandings.
   Where no adverse findings exist, this conference may be waived by management of the audited organization. Such waiver shall be documented in the audit report. For all internal audits, unless unusual operating or maintenance conditions preclude attendance by appropriate management, an audit exit shall be held with management of the audited organization. If there are no adverse findings, management of the audited organization may waive the audit exit. Such waiver shall be documented in the audit report."
5. ANSI N45.2.12 Section 4.4, Reporting:
   a. This paragraph requires that the audit report be signed by the audit team leader which is not always the most expeditious route for the audit report to be issued as soon as practical. RNP will comply with Section 4.4 as clarified to read:
      "An audit report shall be signed by the audit team leader or the leader's supervisor in the absence of the audit team leader. In cases where the audit report is not signed by the audit team leader due to the leader's absence, the record copy of the report must be signed by the audit team leader upon return . The report shall not require the audit team leader's review/concurrence/signature if the audit team leader is no longer employed by Duke Energy at the time audit report is issued. The audit report shall provide:"
   b. RNP will comply with subsection 4.4.3 clarified to read: "Supervisory level personnel with whom significant discussions were held during the course of preaudit (where conducted) , audit, and post audit (where conducted) activities.
   c. Subsection 4.4.6 requires audit reports to include recommendations for corrective actions. RNP may choose not to comply with this requirement. Instead, audit reports are required to document findings.

Regulatory Guide 1.146, Qualification of QA Program Audit Personnel for Nuclear Power Plants (Revision 0) (August, 1980)
ANSI Standard N45.2.23-1978, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants
RNP shall comply with NRC Regulatory Guide 1.146, Revision 0, which endorses ANSI N45.2.23-1978, with the following exceptions:

1. Section 1.4 titled <u>Definitions:</u> Definitions in this Standard which are not included in ANSI

Table C17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

N45.2.10 will be used; definitions which are included in ANSI N45.2.10 will be used as clarified in RNP commitment to Regulatory Guide 1.74.

2. Section 2.2 titled Qualification of Auditors: Subsection 2.2.1 references an ANSI B45.2, which will be assumed to be N45.2. RNP will comply with an alternate subsection 2.2.1 which reads:
   Orientation to provide a working knowledge and understanding of the QA program, including the Regulatory Guides and ANSI standards included in the program, and Duke Energy procedures for performing audits and reporting results.
3. Section 4.1 titled Organizational Responsibility: RNP will comply with this Section with the substitution of the following sentence in place of the last sentence in the Section.

Regulatory Guide 1.146, Qualification of QA Program Audit Personnel for Nuclear Power Plants (Revision 0) (August, 1980)
ANSI Standard N45.2.23-1978, Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants
RNP shall comply with NRC Regulatory Guide 1.146, Revision 0, which endorses ANSI N45.2.23-1978, with the following exceptions:

NOS Management or the Audit Team Leader shall, prior to commencing the audit, assign personnel who collectively have experience or training commensurate with the scope, complexity, or special nature of the activities to be audited.

4. Section 5.3 titled Updating of Lead Auditors' Records: RNP will substitute the following sentence for this Section:
   Records for each Lead Auditor shall be maintained and updated during the annual management assessment as defined in Section 3.2 (as clarified).
5. Section 5.4 titled Record Retention: RNP will substitute the following sentence for this section.
   Qualification records shall be retained as required by the QA Program.
6. Section 2.3.4 titled For Audits: RNP will substitute the following instead of the cited sentence. Prospective Lead Auditors shall demonstrate the ability to effectively implement the audit process and effectively lead an audit team. This process is described in written procedures, which provide for evaluation and documentation of the results of this demonstration. In addition, the prospective Lead Auditor shall have participated in at least two Nuclear Oversight audits within a one-year period preceding the individual's effective date of qualification. Upon successful demonstration of the ability to effectively implement the audit process and effectively lead audits, and having met other provisions of Section 2.3 of ANSI/ASME N45.2.23-1978, the individual may be certified to lead audits.

Table C17-2. Site Specific Response to Regulatory Guides and Industry Standards

Table C17-2 identifies additional Regulatory Guides addressing subjects related to implementation of the QAP but the implementation is site specific and controlled with the UFSAR in accordance with 10 CFR 50.59.

Regulatory Guide 1.8, Personnel Selection and Training

Personnel selection and training is site specific.

Robinson addresses conformance with Regulatory Guide 1.8 in UFSAR Chapter 1 Section 8.

Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions, except for the manager of the radiation control function, who shall meet or exceed the minimum qualifications of ANSI/ANS 3.1-1981, and the STA, who shall have a bachelor's degree or equivalent in a scientific or engineering discipline with specific training in plant design, and response and analysis of the plant for transients and accidents.

Regulatory Guide 1.26, Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants

Quality group classifications and standards trace to the original design and construction of the nuclear power plant and therefore are site specific.

Robinson does not address Regulatory Guide 1.26 in UFSAR Chapter 1 Section 8. Quality group classifications are addressed in UFSAR Chapter 3.

Regulatory Guide 1.29, Seismic Design Classification

Seismic design classification trace to the original design and construction of the nuclear power plant and therefore is site specific.

Robinson addresses conformance with Regulatory Guide 1.29 in UFSAR Chapter 1 Section 8.

Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel

Nonmetallic thermal insulation for austenitic stainless steel trace to the original design and construction of the nuclear power plant and therefore is site specific.

Robinson does not address conformance with Regulatory Guide 1.36 in UFSAR Chapter 1 Section 8. See UFSAR Chapters 5 and 6 for insulation of austenitic stainless steel.

Regulatory Guide 1.54, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants

Quality assurance requirements for protective coatings applied to water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Robinson addresses conformance with Regulatory Guide 1.54 in UFSAR Chapter 1 Section 8.

Table C17-2. Site Specific Response to Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.143, Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants

Design guidance for radioactive waste management systems, structures, and components installed in light-water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Robinson does not address conformance with Regulatory Guide 1.143 in UFSAR Chapter 1 Section 8. Design guidance for radioactive waste management systems, structures, and components is addressed in UFSAR Chapter 11.

Regulatory Guide 1.155, Station Blackout

Addressing Station Blackout is site specific.

Robinson addresses conformance with Regulatory Guide 1.155 in UFSAR Chapter 1 Section 8.

Regulatory Guide 4.15, Quality Assurance for Radiological Monitoring Programs (Normal Operations) – Effluent Streams and the Environment

Quality assurance for radiological monitoring program (normal operations) – effluent streams and the environment is site specific.

Robinson addresses Regulatory Guide 4.15 in UFSAR Chapter 1 Section 8.

C17.3.1 MANAGEMENT

C17.3.1.1 Methodology

There are no Robinson specific amplifications for this section.

C17.3.1.2 Organization

There are no Robinson specific amplifications for this section.

C17.3.1.3 Responsibility

There are no Robinson specific amplifications for this section.

C17.3.1.4 Authority

The program and procedures require that the authority and duties of persons and organizations performing activities affecting quality functions be clearly established and delineated in writing and that these individuals and organizations have sufficient authority and organizational freedom to:

1. Identify quality, nuclear safety, and performance problems.
2. Order unsatisfactory work to be stopped and control further processing, delivery, or installation of nonconforming material.
3. Initiate, recommend, or provide solutions for conditions adverse to quality.
4. Verify implementation of solutions.

C17.3.1.5 Personnel Training and Qualification

There are no Robinson specific amplifications for this section.

C17.3.1.6 Corrective Action

The program requires that an evaluation of adverse conditions such as conditions adverse to quality, nonconformances, failures, malfunctions, deficiencies, deviations, and defective material and equipment is conducted to determine need for corrective action.

Conditions adverse to quality are identified through inspections, assessments, tests, checks, and review of documents.

The program requires corrective action to be initiated to preclude recurrence of significant conditions adverse to quality.

Procedures require follow-up reviews, verifications, inspections, etc., to be conducted to verify proper implementation of corrective action and to close out the corrective action documentation.

The program outlines the methodology for resolution of disputes involving quality and nuclear safety issues arising from a difference of opinion between identifying personnel and other groups.

Significant conditions adverse to quality are reported to appropriate management for review and evaluation.

Periodic review and evaluation of adverse trends are performed by management.

C17.3.1.7 Regulatory Commitments

There are no Robinson specific amplifications for this section.

C17.3.2 PERFORMANCE/VERIFICATION

C17.3.2.1 Methodology

There are no Robinson specific amplifications for this section.

C17.3.2.2 Design Control

There are no Robinson specific amplifications for this section.

C17.3.2.3 Design Verification

There are no Robinson specific amplifications for this section.

C17.3.2.4 Procurement Control

Potential contractors and suppliers are evaluated prior to award of a procurement contract when needed to assure the contractor's or supplier's capability to comply with applicable technical and quality requirements.

Procurement documents, such as purchase specifications, contain or reference the following:

1. Technical, administrative, regulatory, and reporting requirements, including material and component identification requirements, drawings, specifications, codes and industrial standards, test and inspection requirements, and special process instructions.
2. Identification of the documentation to be prepared, maintained, or submitted (as applicable) to RNP for review and approval. These documents may include, as necessary, inspection and test records, qualification records, or code required documentation
3. Identification of those records to be retained, controlled, and maintained by the supplier, and those delivered to the purchaser prior to use or installation of the hardware.

Procurement documents require suppliers to operate in accordance with QA programs which are compatible with the applicable requirements of RNP's QA Program and procedures where their services are utilized in support of plant activities.

C17.3.2.5 Procurement Verification

There are no Robinson specific amplifications for this section.

C17.3.2.6 Identification and Control of Items

Procedures require that materials, parts, and components be identified and controlled to prevent the use of incorrect or defective items. These procedures also require that identification of items be maintained either on the item in a manner that does not affect the function or quality of the item, or on records traceable to the item.

Procedures implementing these requirements provide for the following:

1. Verification that items received at the plant are properly identified and can be traced to the appropriate documentation, such as drawings, specifications, purchase orders, manufacturing and inspection documents, nonconformance reports, or material test

reports.

2. Verification of item identification consistent with the RNP inventory control system and traceable to documentation which identifies the proper uses or applications of the item.

C17.3.2.7 Handling, Storage, and Shipping

Provisions are established to control the shelf life and storage of chemicals, reagents, lubricants, and other consumable materials.

C17.3.2.8 Test Control

Test procedures incorporate or reference the following, as required:

1. Instructions and prerequisites for performing the test,
2. Use of proper test equipment,
3. Mandatory inspection hold points,
4. Acceptance criteria

Test results are documented, evaluated, and their acceptability determined by a qualified, responsible individual or group.

When the acceptance criteria is not met, affected areas are to be retested or evaluated, as appropriate.

C17.3.2.9 Measuring and Test Equipment Control

Portable measuring and test equipment are calibrated by standards at least four times as accurate as the portable measuring and test equipment, unless limited by the state of the art.

Special tools such as torque wrenches, calipers, and micrometers are calibrated to be at least as accurate as the application(s) for which it is used, using standards which are at least as accurate as the special tool being calibrated.

Installed measuring and test instruments are calibrated by instruments at least as accurate as the installed, unless limited by the state of the art.

Reference and transfer standards are traceable to nationally recognized standards; or where national standards do not exist, provisions are established to document the basis for the calibration.

C17.3.2.10 Inspection, Test, and Operating Status

These procedures include the application, removal, and verification of inspection and welding stamps, or other status indicators as appropriate.

Altering the sequence of required tests, inspections, and safety-related operations can only be accomplished by methods outlined in procedures.

C17.3.2.11 Special Process Control

There are no Robinson specific amplifications for this section.

C17.3.2.12 Inspection

There are no Robinson specific amplifications for this section.

C17.3.2.13 Corrective Action

The primary goal of the RNP corrective action program is to improve overall plant operations and performance by identifying and correcting root causes of equipment and human performance problems.

Procedures define requirements for a corrective action program that charges personnel working at or supporting the nuclear plants with the responsibility to identify adverse conditions (including conditions adverse to quality).

Procedures include requirements for verification of the acceptability of the rework/repair of items by reinspection and/or testing in accordance with the original inspection or test requirements or by an accepted alternative inspection and testing method.

Conditions that require rework/repairs are identified through the use of maintenance work request forms.

C17.3.2.14 Control of Documents

Changes to documents are reviewed and approved by the same organization that performed the original review and approval or by other designated qualified responsible organizations.

C17.3.2.15 Records

The structures in which certain records are maintained are designed to prevent destruction, deterioration, or theft. These structures ensure protection against destruction by fire, flooding, theft, and deterioration by the environmental conditions of temperature and humidity.

C17.3.3 ASSESSMENT

C17.3.3.1 Methodology

There are no Robinson specific amplifications for this section.

C17.3.3.2 Independent Review

There are no Robinson specific amplifications for this section.

C17.3.3.3 Independent Assessment

There are no Robinson specific amplifications for this section.

C17.3.3.3.1 Organization

There are no Robinson specific amplifications for this section.

C17.3.3.3.2 Internal Assessment process

There are no Robinson specific amplifications for this section.

C17.3.3.3.3 Internal Audit Program

C17.3.3.3.3.1 Other Reviews Prescribed by the Code of Federal Regulations

There are no Robinson specific amplifications for this section.

C17.3.3.3.3.2 Independent Audit of Fire Protection Program

There are no Robinson specific amplifications for this section.

C17.3.3.3.4 Results

There are no Robinson specific amplifications for this section.

C17.3.3.3.5 Supplier Oversight

There are no Robinson specific amplifications for this section.

C17.3.3.3.6 Independent Audit of QA Functions

There are no Robinson specific amplifications for this section.

C17.3.3.3.7 Audit Frequency Extensions

There are no Robinson specific amplifications for this section.

C17.3.4 REVIEW AND AUDIT

The topics in this section were added to the RNP UFSAR description of the QA Program to relocate certain administrative controls from Technical Specifications. Those relocated administrative controls, indicated by section heading, are either contained below or referenced to the current location.

C17.3.4.1 Procedures, Tests, and Experiments

1. The procedures established, implemented, and maintained for the Quality Assurance Program for effluent and environmental monitoring use guidance from Regulatory Guide 4.15. RNP is not committed to specific guidance within Regulatory Guide 4.15 or to a specific revision to the Regulatory Guide.
2. 10 CFR 50.59 reviews are addressed in Section 17.3.4.2.

C17.3.4.2 Modifications

Requirements for modifications are addressed in Section 17.3.2.2, Design Control.

C17.3.4.3 RNP Technical Specifications and License Changes

Each proposed RNP Technical Specification or Operating License change for the 10CFR 50 license and 7P-ISFSI license is reviewed per Section 17.3.3.2 and submitted to the NRC for approval. The 24P ISFSI RNP Technical Specifications and License are processed by Transnuclear, Inc., and will only be reviewed by the On-Site Review Committee if a plant specific safety issue is identified.

C17.3.4.4 Review of RNP Technical Specifications Violations

Addressed in Section 17.3.4.6, Reportable Event Action.

C17.3.4.5 10CFR 50.59 Review Qualification

10 CFR 50.59 review qualification is addressed in Section 17.3.4.2, 10 CFR 50.59 Reviews.

C17.3.4.6 Plant Nuclear Safety Committee (PNSC)

Requirements for the on-site review committee are addressed in Section 17.3.3.2, Independent Review.

C17.3.4.7 Independent Review Program

The Nuclear Oversight Section Independent Review Program, has been replaced by Section 17.3.3.2, Independent Review.

C17.3.4.8. (Deleted)

There was no content in Robinson UFSAR Section 17.3 Appendix A, QA Program Relocated Technical Specifications Requirements, Section 1.8.

C17.3.4.9. Outside Agency Inspection and Audit Program

See Section 17.3.3.3.3.2, Independent Audit of Fire Protection Program.

C17.3.4.10. Reportable Event Action

See Section 17.3.4.6, Reportable Event Action.

C17.3.4.11. Safety Limit Violation

Requirements for safety limit violations are addressed in 17.3.4.6.

C17.3.4.12. Record Retention

A list of typical operational phase QA Records is included in 17.3.2.15.

Attachment D, Catawba, McGuire, and Oconee Specific QAPD

The term 'Duke Energy Carolinas' as used in this document means Catawba, McGuire, and Oconee Nuclear Plants. If content is specific to a single nuclear plant, that nuclear plant will be identified by name. See Table D17-2 addressing Regulatory Guide 1.8 for example.

Information presented in this attachment was contained in the Duke Energy Carolinas Topical Report Quality Assurance Program prior to Amendment 41.

Where a section contains no descriptive information beyond that in the generic text in the body of the document, a statement is made to that effect and no content is included. See D17.3.1.2, Organization for example.

D17. QUALITY ASSURANCE

D17.1 QA DURING DESIGN AND CONSTRUCTION

Deleted

D17.2 OPERATIONAL QA

Deleted

(NOTE: In August 1992, Amendment 15 of the Duke Energy Carolinas Topical Report reformatted the description of the QA Program to follow Standard Revision Plan Section 17.3, replacing the content of 17.1 and 17.2.)

D17.3 QUALITY ASSURANCE PROGRAM (QAP) DESCRIPTION

INTRODUCTION

As discussed herein, the Quality Assurance Program (QAP) includes the description contained in this document and the procedures providing implementation of the requirements of this document, including the requirements of industry standards to the degree identified in Table 17-1. This Topical Report describes the QAP for those systems, components, items, and services which have been determined to be nuclear safety related. The QAP provides a method of applying graded controls to certain non-nuclear safety related systems, components, items, and services (such as fire protection and radioactive waste structures, systems, and components) through implementing documents.

Duke Energy Carolinas may use QA Conditions as a method for identifying applicability of the QAP, where implementing documents define a Quality Assurance (QA) "Condition" for each level of QA required. These will be designated as "QA Condition______". The quality of systems, components, items, and services within the scope of QA Conditions is assured through implementing documents commensurate with the system's, component's, item's, or service's importance to safety.

In this approach, QA Condition 1 identifies those systems and their attendant components, items, and services which have been determined to be nuclear safety related. These systems are detailed in the Safety Analysis Report applicable to each nuclear station. The Topical Report applies in its entirety to systems, components, items, and services identified as QA Condition 1.

QA Condition 5 covers those systems, components, items, and services which are important to the mitigation of design basis and other selected events as defined in applicable procedures and directives. QA Condition 5 only applies to Oconee Nuclear Station.

QA Conditions 2, 3, 4, and others are defined in implementing documents. These address SSCs and related functions important to the management and containment of liquid, gaseous, and solid radioactive waste, important to fire protection, seismic interaction, etc.

QA Condition 3 includes those fire protection features (systems, components, items, and services) which are credited in addressing 10 CFR 50.48.

Quality assurance program requirements for Oconee, McGuire, and Catawba dry cask storage activities are performed in accordance with applicable 10CFR72.212 reports for each site which invoke the NRC approved 10CFR50 Appendix B QAP as described in this Topical Report.

DEFINITIONS

There are no Duke Energy Carolinas specific definitions.

EXPLANATION OF "QUALITY ASSURANCE"

There is no Duke Energy Carolinas specific content.

QA STANDARDS AND GUIDES

Table D17-1 and D17-2 address Catawba, McGuire, and Oconee conformance to the referenced regulatory and program guidance in NUREG-0800 Section 17.3.

Changes to the content of Table D17-1 are controlled in accordance with 10 CFR 50.54(a). Subsequent changes to the QAP are incorporated in this document as identified in Section 17.3.1.7.

Table D17-2 addresses additional Regulatory Guides that relate to implementation of the QAP but the implementation is site specific and controlled with each site's UFSAR.

Table D17-1. Conformance with QA Regulatory Guides and Industry Standards

Generic Exception:

Table D17-1 addresses Duke Energy Carolinas Conformance of the Quality Assurance Program to certain NRC Regulatory Guides. In so doing, specific editions of industry standards are identified for compliance with exceptions and alternatives. Those identified standards include references to other industry standards for activities including, but not limited to; design, fabrication, inspection, and testing. Those included reference industry standards are considered to be guidance documents for details of how activities may be accomplished. The actual standard to be used in such cases is controlled by each station's current licensing and design bases.

Regulatory Guide 1.28, Rev (2), Feb. 1979 – Quality Assurance Program Requirements (Design and Construction)
Duke Energy Carolinas conforms to Regulatory Guide 1.28 Rev (2) and ANSI N45.2-1977 with the clarifications and exceptions noted below.
Exception to ANSI N45.2 Section 5. Duke Energy Carolinas procurement documents shall require suppliers to provide a quality assurance program consistent with the pertinent requirements of 10 CFR Part 50 Appendix B instead of ANSI N45.2-1977. Alternate requirements for purchase of Commercial Grade Items are described in this table addressing compliance for Regulatory Guide 1.123.

Regulatory Guide 1.30, Rev 0, Quality Assurance Requirements for the Installation, Inspection and Testing of Instrumentation and Electric Equipment
Duke Energy Carolinas conforms to Regulatory Guide 1.30 Rev 0 and ANSI N45.2.4-1972 with the following Clarifications and Exceptions:
Conforms with no exceptions.

Regulatory Guide 1.33, Rev 2, Quality Assurance Program Requirements (Operation)
Duke Energy Carolinas conforms to Regulatory Guide 1.33 Rev 2 and ANSI N18.7-1976/ANS-3.2 with the following Clarifications and Exceptions:
Regulatory position C.4 modifies the audit frequencies in Section 4.5 of ANSI N18.7. Duke Energy Carolinas takes exception to this regulatory position. The audits of selected aspects of operational phase activities as identified in Section 17.3.3.3.3, Internal Audit Program, are performance based. The schedule is based on plant performance and importance to safety but at a frequency not to exceed twenty-four months with extensions as allowed in Section 17.3.3.3.7, Audit Frequency Extensions.
Regulatory Guide 1.33, Rev 2, Quality Assurance Program Requirements (Operation)
Duke Energy Carolinas conforms to Regulatory Guide 1.33 Rev 2 and ANSI N18.7-1976/ANS-3.2 with the following Clarifications and Exceptions:
Exception to ANSI N18.7-1976, Section 5.2.15, Review, Approval and Control of Procedures,

Table D17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

which states in part that, "Plant procedures shall be reviewed by an individual knowledgeable in the area affected by the procedure no less frequently than every two years to determine if changes are necessary. A revision to a procedure constitutes a procedure review." In lieu of this paragraph, Duke Energy addresses programmatic controls in Section 17.3.2.14 to continually identify procedure revisions which may be needed to ensure that procedures are appropriate for the circumstance and are maintained current.

Exception to ANSI N18.7-1976, Section 5.2.13.1, Procurement Document Control: When purchasing commercial-grade calibration services from certain accredited calibration laboratories, the procurement documents are not required to impose a QAP consistent with ANSI N45.2-1977. Alternate requirements described in the QA Topical Report for Regulatory Guide 1.123 may be implemented in lieu of imposing a QAP consistent with ANSI N45.2-1977. When purchasing nuclear safety related material, equipment and services, the supplier is required to the meet applicable criteria of 10 CFR 50, Appendix B and 10 CFR 21– with the exception that SSCs categorized as Safety-Related, Low Safety Significant (RISC-3) in accordance with 10CFR50.69 and the site license are no longer subject to the requirements of this document. These 50.69 LSS SSCs are no longer subject to the requirements of 10 CFR 50 Appendix B, 10 CFR Part 21 and other regulations as noted in the rule. Procedures provide guidance for specific process changes as part of 10 CFR 50.69 implementation.

Exception to Paragraph C.3 of Regulatory Guide 1.33 and ANSI N18.7-1976 Section 4.3: Independent Review Program requirements are replaced by Section 17.3.3.2, Independent Review. This exception uses NRC Safety Evaluation dated January 13, 2005 to Nuclear Management Company (ADAMS ML050210276).

Section 5.2.2 titled Procedure Adherence first paragraph addresses temporary change to procedures, which is clarified as follows: Temporary changes to procedures, tests, or experiments may be made provided; a) such change does not change the intent of the original procedure, test, or experiment; b) the change is approved by two members of the plant management staff, at least one of whom holds a Senior Reactor Operator License on the unit affected; and c) the change is documented and approved as a permanent change or deleted within 14 days of implementation.

Regulatory Guide 1.37, Rev 0, Quality Assurance Requirements for Cleaning of Fluid Systems and Associated Components of Water-Cooled Nuclear Power Plants
Duke Energy Carolinas conforms to Regulatory Guide 1.37 Rev 0 and ANSI N45.2.1-1973 with the following clarifications and exceptions:
Conforms with no exceptions.

Regulatory Guide 1.38, Rev 2, May 1977 – Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage and Handling of Items for Water-Cooled Nuclear Power Plants
Duke Energy Carolinas conforms to Regulatory Guide 1.38 Rev 2 and ANSI N45.2.2-1972 with the following Clarifications and Exceptions:
Container markings shall be marked on at least one side (A.3.9(1)) and shall be applied with waterproof ink or paint in characters of a legible size, and caps and plugs for pipe and fittings are required unless specified by Engineering, and off-site inspection, examination, and testing is monitored by personnel qualified to ANSI N45.2.12 in lieu of ANSI N45.2.6.

Regulatory Guide 1.38, Rev 2, May 1977 – Quality Assurance Requirements for Packaging, Shipping, Receiving, Storage and Handling of Items for Water-Cooled Nuclear Power Plants
Duke Energy Carolinas conforms to Regulatory Guide 1.38 Rev 2 and ANSI N45.2.2-1972 with the following Clarifications and Exceptions:
Section 6.2.4 of ANSI N45.2.2 - 1972, titled Storage of Food and Associated Items. The sentence is replaced with the following: "The use or storage of food, drinks, and salt tablet dispensers in any storage area shall be controlled and shall be limited to designated areas where such use or storage is not deleterious to stored items."

Regulatory Guide 1.39, Rev (2), Sept. 1977 – Housekeeping Requirements for Water-Cooled Nuclear Power Plants
Duke Energy Carolinas conforms to Regulatory Guide 1.39 Rev 2 and ANSI N45.2.3-1973 with the following clarifications and exceptions:
Personnel accountability for personnel entering housekeeping zones I, II, and III without materials shall be maintained by housekeeping logs or alternate methods such as radiation work permits, confined space permits, work requests or other accepted methods capable of assuring personnel accountability.

Regulatory Guide 1.58, Rev (1), Sept. 1980 – Qualification of Nuclear Power Plant Inspection, Examination and Testing Personnel
Duke Energy Carolinas conforms Regulatory Guide 1.58 Rev 1 and ANSI N45.2.6-1978 with the following Clarifications and Exceptions:
Duke Energy Carolinas nondestructive examination (NDE) personnel will meet the qualification requirements of SNT TC-1A and ANSI/SNT-CP-189 as governed by the applicable ASME Section XI requirement or other code requirement consistent with the conditions identified in 10 CFR 50.55a. Operational/functional testing personnel will meet the requirements of ANSI N18.1 or ANS 3.1 rather than ANSI N45.2.6. This reflects Regulatory Position C.1. With regard to Section 3 of ANSI N45.2.6-1978 titled <u>Qualifications</u>: Only personnel performing NDE (such as LP, MT, UT, and RT) are required to be grouped in levels of capability and certified for inspection, review, and evaluation of inspection data, and reporting of inspection and test results. In lieu of qualification by Levels, inspection personnel may be qualified based on pre-established experience, education, on-the-job training, written examinations and proficiency tests associated with the specific activity. Proficiency tests are given to personnel performing independent QC inspections and documented acceptance criteria are developed to determine if individuals are properly trained and qualified. Certificates of qualification delineate the functions personnel are qualified to perform. Qualification records are maintained and performance evaluations conducted at least once every three years. If organizations elect to utilize qualifications by levels, Level I inspectors receive a minimum of 4 months experience as Level I before being certified as Level II, in lieu of one year experience recommended by ANSI N45.2.6 Section 3.5.2(1). Organizations identify in their procedures if they qualify their inspectors by Level or by task qualifications. Inspectors are only assigned functions for which they have been qualified.

Table D17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

Regulatory Guide 1.64, Rev (2), June 1976 – Quality Assurance Requirements for the Design of Nuclear Power Plants

Duke Energy Carolinas conforms to Regulatory Guide 1.64, Rev. 2 and ANSI Standard N45.2.11-1974 with the following Clarifications and Exceptions:

The use of the originator's immediate supervisor for design verification shall be restricted to special situations where the immediate supervisor is the only individual capable of performing the verification. Advance justification for such use shall be documented and signed by the supervisor's management. And the frequency and effectiveness of the supervisor's use as design verifier are independently verified to guard against abuse. The supervisor will not be the design verifier on work for which he is the actual performer / originator.

Regulatory Guide 1.74, Rev (0), Feb. 1974 – Quality Assurance Terms and Definitions

Duke Energy Carolinas conforms to Regulatory Guide 1.74, Rev 0 and ANSI N45.2.10-1973 with the following Clarifications and Exceptions:

The quality assurance terms and definitions contained in ANSI N45.2.10-1973 are generally used in describing and implementing the quality assurance program described in this QAPD except where terms are explicitly defined in this document.

Regulatory Guide 1.88, Rev (2), Oct. 1976 - Collection, Storage, and Maintenance of Nuclear Power Plant Quality Assurance Records

Duke Energy Carolinas conforms to Regulatory Guide 1.88, Rev. 2 and ANSI N45.2.9-1974 with the following Clarifications and Exceptions:

The records storage facilities have a minimum 3-hour rating. A qualified Fire Protection Engineer (meeting Professional Member grade qualifications of the SFPE) will evaluate record storage areas (including satellite files) to assure records are adequately protected from damage.

The Duke Energy Carolinas program for storage of records on microfilm, dual storage or in electronic format meets the preservation requirement for the retention of QA Records.

See standard exception in Table 17-1 Regulatory Guide 1.88 for the appropriate controls on quality in the management of electronic records.

Regulatory Guide 1.94, Rev (1), Apr. 1976 – Quality Assurance Requirements for Installation, Inspection, and Testing of Structural Concrete and Structural Steel During the Construction Phase of Nuclear Power Plants

Duke Energy Carolinas conforms to Regulatory Guide 1.94. Rev. 1 and ANSI N45.2.5-1974 with the following Clarifications and Exceptions:

The length of bolts shall be flush with the outside face of the nut.
Section 5.5 requires inspection of structural steel welding to be performed in accordance with the provisions of Section 6 of the AWS D1.1. Visual Weld Acceptance Criteria (VWAC) for Structural Welding at Nuclear Power Plants, NCIG-01, Revision 2, prepared by the Nuclear Construction Issues Group (NCIG) and accepted by the NRC in their letter to the NCIG dated June 26, 1985 may be used as an alternative to AWSD1.1 for non ASME Code structural weld inspections. (July 31, 2000 J M Farley SER)

Regulatory Guide 1.116, Rev (0-R), June 1976, (Reissued May 1977) – Quality Assurance Requirements for Installation, Inspection, and Testing of Mechanical Equipment and Systems
Duke Energy Carolinas conforms to Regulatory Guide 1.116 Rev (0-R) and ANSI N45.2.8-1975 with the following Clarifications and Exceptions:
Conforms

Regulatory Guide 1.123, Rev (1), July 1977 – Quality Assurance Requirements for Control of Procurement of Items and Services for Nuclear Power Plants
Duke Energy Carolinas conforms to Regulatory Guide 1.123 and ANSI N45.2.13-1976 with the following clarifications and exceptions:
Section 3.2, "Content of the Procurement Documents," Subsection 3.2.3, "QAP Requirement," Duke Energy Carolinas takes the following exception: See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.

Regulatory Guide 1.144, Rev (1), Sept. 1980 - Auditing of Quality Assurance Programs for Nuclear Power Plants
Duke Energy Carolinas conforms to Regulatory Guide 1.144, Rev 1 and ANSI N45.2.12-1977 with the following clarifications or exceptions:
Section 4.4.6. In lieu of making recommendations for correcting program deficiencies we will identify the deficiencies to the audited organization. For external audits, the results of the audit will be provided to the audited organization in lieu of the audit report. Also, the re-evaluation may be extended to 15 months and the triennial period as specified in Regulatory Position c.3.b.(2) may be extended as described in Section 17.3.3.3.7, Audit Frequency Extensions. Additionally, the Duke Energy Carolinas QAP meets regulatory position C.3.b of this regulatory guide, as clarified by NRC Information Notice 86-21, Supplement 2. Internal Technical Audits shall require a response describing corrective action and implementation schedule as requested by the audit report but not to exceed sixty days of receipt of the audit report. See standard exceptions in Table 17-1 for Regulatory Guide 1.123 for the procurement of Commercial Grade Items and services including, purchasing commercial-grade calibration services from calibration laboratories.

Regulatory Guide 1.146, Rev (0), Aug. 1980 – Qualification of Quality Assurance Program Audit Personnel for Nuclear Power Plants
Duke Energy Carolinas conforms to Regulatory Guide 1.146 Rev 0 and ANSI N45.2.23-1978 with the following clarifications and Exceptions:
In lieu of prospective lead auditors participating in a minimum of five QA audits within a period of three years prior to date of certification, prospective lead auditors shall demonstrate their ability to effectively lead an audit team and shall have participated in at least one nuclear QA audit within one year preceding the individual's effective date of qualification. Upon successful demonstration of the ability to lead audits, and having met the other provisions of ANSI N45.2.23-1978, the individual may be certified as being qualified to lead audits. This process is described in approved procedures which require documentation of the evaluation and

Table D17-1. Conformance with QA Regulatory Guides and Industry Standards (Continued)

demonstration of results.

Regulatory Guide 1.152 Criteria for Programmable Digital Computer System Software in Safety-Related Systems of Nuclear Power Plants
Conformance to Regulatory Guide 1.152 was not addressed during the licensing of the operating Duke Energy Carolinas Nuclear plants.
Regulatory Guide 7.10, Establishing Quality Assurance Programs for Packaging Used in the Transport of Radioactive Material
Duke Energy Carolinas does not conform to Regulatory Guide 7.10. This QAPD is used to satisfy applicable Quality Assurance requirements for packaging and transportation of radioactive material.
Generic Letter 89-02, Actions to Improve the Detection of Counterfeit and Fraudulently Marketed Products
See Table 17-1.

Table D17-2. Site Specific Response to Regulatory Guides and Industry Standards

Table D17-2 identifies additional Regulatory Guides addressing subjects related to implementation of the QAP but the implementation is site specific and controlled with each site's UFSAR in accordance with 10 CFR 50.59.

Regulatory Guide 1.8, Personnel Selection and Training

Personnel selection and training is site specific.

Catawba addresses conformance with Regulatory Guide 1.8 in UFSAR Chapter 1 Section 7.

McGuire addresses conformance with Regulatory Guide 1.8 in UFSAR Chapter 1 Table 1-4.

Oconee does not address conformance with Regulatory Guide 1.8. Personnel selection and training is addressed in UFSAR Chapter 13.

At Catawba and McGuire, each member of the unit staff shall meet or exceed the minimum qualifications of ANSI-N18.1-1971 for comparable positions, except:

1. The Radiation Protection Manager, who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975.

2. The education and experience eligibility requirements for licensed operators shall meet or exceed the guidelines outlined by the National Academy for Nuclear Training (NANT), which have been found acceptable by the Nuclear Regulatory Commission (NRC) for meeting 10 CFR 55.31 and have been incorporated into applicable station training procedures.

For the purposes of 10 CFR 55.4, a licensed Senior Reactor Operator (SRO) and a licensed Reactor Operator (RO) are those individuals who, in addition to meeting the requirements of TS 5.3.1, perform the functions described in 10CFR 50.54(m).

At Oconee, each member of the unit staff shall meet or exceed the minimum qualifications described in Section 4 of ANSI/ANS-3.1-1978, "Selection and Training of Nuclear Power Plant Personnel" except:

1. The Operations Manager shall have a minimum of eight years of responsible nuclear or fossil station experience, of which a minimum of three years shall be nuclear station experience. A maximum of two years of the remaining five years of experience may be fulfilled by academic training, or related technical training, on a one-for-one time basis.

2. The Assistant Operations Manager - Shift shall have a minimum of eight years of responsible nuclear or fossil station experience, of which a minimum of three years shall be nuclear station experience. A maximum of two years of the remaining five years of experience may be fulfilled by academic training, or related technical training on a one-for-one time basis.

3. The education and experience eligibility requirements for licensed operators shall meet or exceed the guidelines outlined by the National Academy for Nuclear Training (NANT), which have been found acceptable by the Nuclear Regulatory

Commission (NRC) for meeting 10 CFR 55.31 and have been incorporated into applicable station training procedures.

For the purpose of 10 CFR 55.4, a licensed Senior Reactor Operator (SRO) and a licensed Reactor Operator (RO) are those individuals who, in addition to meeting the requirements of TS 5.3.1, perform the functions described in 10 CFR 50.54(m).

Regulatory Guide 1.26, Quality Group Classifications and Standards for Water-, Steam-, and Radioactive-Waste-Containing Components of Nuclear Power Plants

Quality group classifications and standards trace to the original design and construction of the nuclear power plant and therefore are site specific.

Catawba addresses conformance with Regulatory Guide 1.26 in UFSAR Chapter 1 Section 7.

McGuire addresses conformance with Regulatory Guide 1.26 in UFSAR Chapter 1 Table 1-4.

Oconee does not address conformance with Regulatory Guide 1.26. Quality group classifications and standards are addressed in UFSAR Section 3.2.2.

Regulatory Guide 1.29, Seismic Design Classification

Seismic design classification trace to the original design and construction of the nuclear power plant and therefore is site specific.

Catawba addresses conformance with Regulatory Guide 1.29 in UFSAR Chapter 1 Section 7.

McGuire addresses conformance with Regulatory Guide 1.29 in UFSAR Chapter 1 Table 1-4.

Oconee does not address conformance with Regulatory Guide 1.29. Seismic design classifications are addressed in UFSAR Section 3.2.1.

Regulatory Guide 1.36, Nonmetallic Thermal Insulation for Austenitic Stainless Steel

Nonmetallic thermal insulation for austenitic stainless steel trace to the original design and construction of the nuclear power plant and therefore is site specific.

Catawba addresses conformance with Regulatory Guide 1.36 in UFSAR Chapter 1 Section 7.

McGuire addresses conformance with Regulatory Guide 1.36 in UFSAR Chapter 1 Table 1-4.

Oconee does not address conformance with Regulatory Guide 1.36. Thermal insulation for austenitic stainless steel is addressed in UFSAR Section 5.4.

Regulatory Guide 1.54, Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants

Quality assurance requirements for protective coatings applied to water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Catawba addresses conformance with Regulatory Guide 1.54 in UFSAR Chapter 1 Section 7.

McGuire addresses conformance with Regulatory Guide 1.54 in UFSAR Chapter 1 Table 1-4.

Oconee does not address conformance with Regulatory Guide 1.54. Protective coatings are addressed in UFSAR Section 6.2.1.6.

Regulatory Guide 1.143, Design Guidance for Radioactive Waste Management Systems, Structures, and Components Installed in Light-Water-Cooled Nuclear Power Plants

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Design guidance for radioactive waste management systems, structures, and components installed in light-water-cooled nuclear power plants trace to the original design and construction of the nuclear power plant and therefore is site specific.

Catawba addresses conformance with Regulatory Guide 1.143 in UFSAR Chapter 1 Section 7.

McGuire addresses conformance with Regulatory Guide 1.143 in UFSAR Chapter 1 Table 1-4.

Oconee does not address conformance with Regulatory Guide1.143. Design guidance for radioactive waste management systems, structures, and components is addressed in UFSAR Chapter 11.

Regulatory Guide 1.155, Station Blackout

Addressing Station Blackout is site specific.

Catawba addresses conformance with Regulatory Guide 1.155 in UFSAR Chapter 1 Section 7.

McGuire addresses conformance with Regulatory Guide 1.155 in UFSAR Chapter 1 Table 1-4.

Oconee address conformance with Regulatory Guide 1.155 in UFSAR Chapter 8.

Regulatory Guide 4.15, Quality Assurance for Radiological Monitoring Programs (Normal Operations) – Effluent Streams and the Environment

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Quality assurance for radiological monitoring program (normal operations) – effluent streams and the environment is site specific.

Catawba addresses conformance with Regulatory Guide 4.15 in UFSAR Chapter 1 Section 7.

McGuire does not address conformance to Regulatory Guide 4.15 in UFSAR Chapter 1 Table 1-4. The radiological monitoring program is addressed in UFSAR Chapter 11.

Oconee does not address conformance with Regulatory Guide 4.15. The radiological monitoring program is addressed in UFSAR Chapter 11.

D17.3.1 MANAGEMENT

D17.3.1.1 Methodology

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.1.2 Organization

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.1.3 Responsibility

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.1.4 Authority

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.1.5 Personnel Training and Qualification

The following provide Duke Energy Carolinas specific amplifications for this section.

A training program is established for each nuclear station and support organization to develop and maintain an organization qualified to be responsible for operation, engineering, testing, inspection, maintenance, engineering changes and other technical aspects of the nuclear station involved. The program is formulated to provide the required training based on individual employee experience and intended position. The program is in compliance with NRC licensing requirements, where applicable. The training program is such that trained and qualified operating, maintenance, work control, engineering, inspection, testing, technical support and supervisory personnel are available in necessary numbers at the times required. In all cases, the objectives of the training program shall be to assure safe and reliable operation of the station.

A continuing effort is used after a station goes into commercial operation for training of replacement personnel and for periodic retraining, reexamining, and/or recertifying as required to assure that personnel remain proficient. Personnel receive orientation training in basic QA policies and practices.

Personnel receive additional training, as appropriate, which addresses specific topics such as NRC regulations and guides, QA procedures, auditing and applicable codes and standards. Special training of personnel in QA related matters, particularly new or revised requirements, is conducted as necessary. Training and qualification records are maintained for each employee. Documentation of training includes the objectives, content of the program, attendees, and date of attendance.

D17.3.1.6 Corrective Action

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.1.7 Regulatory Commitments

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.2 PERFORMANCE/VERIFICATION

D17.3.2.1 Methodology

The following provide Duke Energy Carolinas specific amplifications for this section.

The program receives on-going review and is revised as necessary to assure its continued effectiveness.

D17.3.2.2 Design Control

Each design document is checked by another individual qualified in the same discipline and is reviewed for concept and conformity with applicable codes, standards, and other design inputs (as specified within the design documentation package). The document is approved by the individual having overall responsibility for the design function. A review of each specification is made to assure incorporation of necessary QA information. The entire review process is documented.

Computer programs are controlled in accordance with appropriate department procedures, whereby programs are certified to demonstrate their applicability and validity.

D17.3.2.3 Design Verification

Analytical models, theories, examples, tables, codes, computer programs, etc., used as bases for design must be referenced in the design document and their application verified in the design verification. Model tests, when required, to prove the adequacy of concept or design are reviewed and approved by the responsible engineer. The tests used for design verification must meet all the requirements of the designing activity. Computer programs are controlled in accordance with the applicable software QA document whereby programs are certified to demonstrate their applicability and validity.

Following completion of design and evaluation of an engineering change, the responsible individual/organization summarizes the engineering change design and identifies the design documents and information required for engineering change implementation. This information is provided for design verification. This addresses such items as:

a) A description of the engineering change.
b) References utilized in the evaluation and design of the engineering change, and necessary for the implementation of the engineering change.
c) Special installation instructions.
d) Operational, test, maintenance and inspection requirements.
e) Materials, parts and components required in order to implement the engineering change.
f) Drawings revised and/or requiring revision.
g) UFSAR revision(s) and/or Technical Specifications amendment(s) necessary.
h) Whether or not the engineering change requires a license amendment.

D17.3.2.4 Procurement Control

Procedures identify the responsibility within Nuclear Generation for the technical qualification of suppliers and control of the initial procurement of nuclear safety related items and services. Procurement requirements/specifications are prepared, checked, and approved by appropriate personnel and forwarded to Nuclear Supply Chain for procurement actions from qualified suppliers.

Technical qualifications are determined by engineering personnel. Commercial qualification is determined by Supply Chain following evaluation of bids from qualified suppliers. Bid evaluation includes evaluation of the technical, quality and commercial qualifications of the prospective suppliers.

NOS performs qualification of supplier QA programs. NOS may place a supplier on the Qualified Suppliers List following review, approval and acceptance of an audit performed by another licensed nuclear utility or joint utility audit team. Review of such third party audits shall ensure that items to be procured are within the audit scope and any unique plant quality and technical requirements are adequately addressed by such audits. When basic components and services are procured from a supplier whose quality performance has not been verified by audit, additional assurance of product quality shall be obtained by supplier surveillance, inspection or test.

Materials, parts and components shall be procured to specified technical and quality requirements at least equivalent to those applicable to the original equipment or those specified by a properly reviewed and approved revision. As required by the applicable purchase documents, suppliers furnish documentation which identifies the material and equipment purchased and the specific procurement requirements met by the items. Also, as required by the applicable purchase documents, suppliers will provide documentation which identifies any procurement requirements which have not been complied with, together with a description of any deviations and repair records.

Procurement of materials, parts, components and services associated with nuclear safety related structures, systems, and components is controlled during the operational life of the station so as to assure the suitability for their intended service and that the safety and reliability of the station are not compromised.

Procurement information for nuclear safety related materials, parts and components is reviewed to assure that QA, technical and regulatory requirements including supplier documentation requirements are adequately incorporated into the purchase document(s). Significant changes to the content of such purchasing information are reviewed and approved in a manner consistent with the original.

Critical characteristics for the dedication of Commercial Grade Items are determined by Procurement Engineering or Supply Chain technical sponsors and approved by the responsible engineering personnel based on the manufacturer's published specifications and the intended safety function for the items. Critical characteristics used for acceptance and dedication of commercial grade items are selected to provide reasonable assurance that the items will meet their catalog or manufacturer specifications and will perform the necessary safety functions in the intended applications. Verification of critical characteristic acceptability will be by manufacturer/supplier survey, source verification, receipt tests or inspections, or post installation testing. Historical data, when documented, will represent industry wide experience.

If verification of a critical characteristic is to be by supplier survey, NOS is responsible for verifying the acceptability of the supplier control of the identified critical characteristic.

D17.3.2.5 Procurement Verification

NOS Vendor Quality performs a documented on-going evaluation of each qualified supplier in order to maintain the supplier on the qualified suppliers list. The evaluation is performed to a depth consistent with the item's or service's importance to safety, complexity, and the quantity

and frequency of procurement. As applicable, this evaluation takes into account (1) review of supplier-furnished documents such as certificates of conformance, nonconformance notices, and corrective actions, (2) results of previous source verifications, audits, and receiving inspections, (3) operating experience of identical or similar products furnished by the same supplier, and (4) results of audits from other sources (e.g., customer, ASME, or NRC audits). The results of the evaluations are reviewed and appropriate corrective action initiated. Adverse findings resulting from these evaluations are periodically reviewed in order to determine if, as a whole, they result in a significant condition adverse to quality and to provide input to support supplier audit activities conducted by the licensee or a third party auditing entity.

Suppliers of nuclear safety related items or services are re-evaluated by means of an audit at least triennially, if initial qualification was by audit or pre-award survey. The triennial audit schedule may be extended as identified in Section 17.3.3.3.7, Audit Frequency Extensions.

NOS is responsible for oversight when procurement documents require characteristics or processes to be witnessed, inspected or verified at the supplier shop. NOS surveillance activities assure that the supplier complies with all quality requirements outlined in the procurement document(s). The surveillance representative has the authority and responsibility to stop work when the required quality standards are not met.

D17.3.2.6 Identification and Control of Items

Specific identification requirements are as follows:

a) Materials, parts, components, assemblies, and subassemblies shall be identified either on the item or records traceable to the item to show that only correct items are received, issued and installed.
b) Some components, such as pressure vessels are identifiable by nameplates as required by applicable codes, or Duke Energy Carolinas specifications. Materials, parts, and components are traceable from such identification to a specific purchase order to manufacturer's records and to QA records and documentation.
c) When required by procurement documents, materials are identified by heat, batch or lot numbers which are traceable to the original material at receipt. Upon receipt, a unique tracking number is assigned to provide traceability. When several parts are assembled, a list of parts and corresponding numbers is included in the documentation.
d) When required by specifications or codes and standards, identification of material or equipment with the corresponding mill test reports, certifications and other required documentation is maintained throughout the life of the material or equipment by a unique tracking number.
e) Sufficient precautions will be taken to preclude identifying materials in a manner that will affect the function or quality of the item being identified.

Control of material, parts and components is governed by approved procedures. Specific control requirements include:

1) Nonconforming or rejected materials, parts, or components are identified to assure that they will not be inadvertently used.
2) The verification of correct identification of material, parts, and components is required prior to release for assembling, shipping and installation.
3) Upon receipt, procedures require that materials, parts or components undergo a receipt inspection to assure they are properly identified and that the supporting documentation is available as required by the procurement requirements/specifications. Items having limited shelf or service life are identified and controlled.
4) Each organization which performs an operation that results in a change in the material, part or component is required to make corresponding revisions and/or additions to the documentation record as applicable.

When a designated item is subdivided, each subdivision is identified in accordance with the above requirements. Where physical identification of an item is impractical or insufficient, physical separation, administrative controls or other appropriate means are utilized.

D17.3.2.7 Handling, Storage, and Shipping

Conforming nuclear safety related materials, parts and components are stored in controlled, segregated areas designated for the storage of such items. Inspections and examinations are performed on a periodic basis to assure that recommended shelf life of chemicals, reagents, and other consumable materials is not exceeded. Hazardous items are stored in suitable environments with controls to prevent contamination of nuclear safety related structures, systems, or components.

D17.3.2.8 Test Control

Test controls include requirements on the review and approval of test procedures, and on the review and approval of changes to such procedures, as discussed in Section 17.3.2.14, "Document Control." Also, specific criteria are established with regard to procedure content. Examples of items which must be considered in the preparation and review of procedures include:

a) References to material necessary in the preparation and performance of the procedure, including applicable design documents.
b) Tests which are required to be completed prior to, or concurrently with, the specified testing.
c) Special test equipment required to perform the specified testing.
d) Limits and precautions associated with the testing.
e) Station, unit and/or system status or conditions necessary to perform the specified testing.
f) Criteria for evaluating the acceptability of the results of the specified testing, compatible with any applicable design specifications.

Test procedures contain the following information or require this information be documented:

1) Requirements and acceptance limits contained in applicable design and vendor documents.
2) Instructions for performing the test.
3) Test prerequisites such as calibrated instrumentation, adequate test equipment and instrumentation including their accuracy requirements, completeness of the item to be tested, suitable and controlled environmental conditions, and provisions for data collection and storage.
4) Mandatory inspection hold points.
5) Acceptance and rejection criteria.
6) Methods of documenting or recording test data and results.
7) Provisions to assure test prerequisites have been met.

Requirements are also established for verification of test completion and for determining acceptability of tests results. Test results are reviewed and accepted by the testing organization and the organization responsible for the item being tested. In the event that test results do not meet test acceptance criteria, a review of the test, test procedure and/or test results is conducted to determine the cause, required corrective action, and retest as necessary.

In addition to the above periodic testing, after maintenance to, or modification of, nuclear safety related structures, systems and components, other post maintenance testing, post modification testing, or functional verifications are performed and documented as required to verify satisfactory performance of the affected items. Post maintenance/modification functional verifications are not subject to the requirements of periodic testing described above because they are acceptable good industrial practices that are simple and straightforward. Included in these tests are such items as diesel generators, reactor control rod systems, and leak testing of appropriate pressure isolation valves.

D17.3.2.9 Measuring and Test Equipment Control

Site specific content is retained for item c) as follows:

c) The tag or records for devices that have been acceptably calibrated include the date of calibration, the date the next calibration is due, an indication that the device is within calibration specifications and the identification of the individual who was responsible for performing the calibration.

Installed instrumentation is subject to the requirements of the Technical Specification and is not subject to the tagging requirements discussed in 17.3.2.9 c) and d). The NOS-Audit section verifies implementation of the calibration program through periodic audits.

The basis for this exception on the installed Technical Specification required equipment is the Preventive Maintenance Periodic Testing (PMPT) program. This is a computerized scheduling program that automatically schedules PMPT using model work orders. When devices have been acceptably calibrated, the clock starts for the next calibration due date. The indication that the device is within calibration specifications and identification of the individual who was responsible for performing the calibration is documented within the calibration procedure for the device. If the device fails to meet calibration specifications, it will be repaired, replaced and/or engineering involvement will be requested to further evaluate. The PMPT program along with the calibration procedures address all the requirements in Section 17.3.2.9 items c and d. Therefore, there is no need to place tags on the devices to identify the calibration status.

D17.3.2.10 Inspection, Test, and Operating Status

Inspections and tests required by the written approved procedures which address work activities are infrequently temporarily deferred. When such a deferral does occur, a discrepancy is considered to exist and documentation of the acceptable completion of the affected work activity is not performed until the discrepancy is resolved.

Proposed tests and experiments which affect station nuclear safety and are not addressed in the Updated Final Safety Analysis Report or Technical Specifications shall be prepared and approved in a manner identical to that used for station procedures as described in Section 17.3.2.14, "Document Control." These proposed tests and experiments shall be reviewed by a knowledgeable individual/organization other than the individual/organization which prepared the proposed tests and experiments.

D17.3.2.11 Special Process Control

The QAP contains or references procedures for the control of special processes such as welding, heat treating, NDE, coatings, crimping and cleaning. These procedures shall provide for documented evidence of acceptable accomplishment of special processes using qualified procedures, equipment, and personnel.

D17.3.2.12 Inspection

Independent inspections, examinations, measurements, observations, or tests of materials, products or activities are conducted, where necessary, to assure quality. If inspection of processed material or products is impossible or disadvantageous, indirect control by monitoring processing methods, equipment, and personnel is provided. Both inspection and process monitoring are provided when control is inadequate without both.

In addition to the content identified in 17.3.2.12, inspection procedures, instructions, and checklists contain the following information or require this information on inspection reports:

a) Measuring and test equipment information

b) Identification of required procedures, drawings, specifications, etc.

The personnel performing these inspections are examined and certified in their particular category. Current qualification and certification files are maintained for each inspector. NDE inspectors are certified in accordance with required codes and standards (See Table 17-1 Regulatory Guide 1.58). Written procedures require the test and certification of inspectors in other categories such as Mechanical, Electrical, and Structural as described in the appropriate QA manual. For cases where inspectors will perform limited functions within a category, they are tested and certified to those limitations. These inspectors are only allowed to perform inspections specifically defined in this limited certification.

For inspections of concrete containments, personnel fulfilling the role of Responsible Engineer, shall be a Registered Professional Engineer experienced in evaluating the in-service condition of structural concrete and knowledgeable of the design and construction codes and other criteria used in the design and construction of the concrete containment structure. The Responsible Engineer may also perform inspections as discussed in this section.

The inspection criteria for performing inspections are established from codes, specifications, and standards applicable to the activity. Examples of activities subject to inspection include:

a) Activities specified by the ASME Code Section XI
b) Special processes
c) Modifications
d) Maintenance
e) Material Receipt

After inspection data is collected and reviewed by the inspector, the reports are technically reviewed by personnel designated to perform that function.

D17.3.2.13 Corrective Action

Procedures require that conditions adverse to quality be corrected. In the case of significant conditions adverse to quality, the procedures assure that the cause of the condition is determined and action be taken to preclude repetition. Performance and verification personnel are to:

a) Identify conditions that are adverse to quality.
b) Suggest, recommend, or provide solutions to the problems as appropriate.
c) Verify resolution of the issue.

Additionally, performance and verification personnel are to ensure that reworked, repaired, and replacement items are to be inspected and tested in accordance with the original inspection and test requirements or specified alternatives.

Discrepancies revealed during the performance of station operation, maintenance, inspection and testing activities must be resolved prior to verification of the completion of the activity being performed. In the event of a significant malfunction of nuclear safety related structures, systems, and components, the cause of the failure is evaluated and appropriate corrective action taken. Items of the same type are evaluated to determine whether or not they can be expected to continue to function in an appropriate manner. This evaluation is documented in accordance with applicable procedures.

Nuclear safety related materials, parts and components which are determined to be nonconforming are identified, segregated or otherwise controlled (e.g. by a conditional release) in such a manner as to preclude their inadvertent substitution for and use as conforming materials, parts and components. The determination of an item's nonconformance is documented and is retained on file by Nuclear Generation and, as appropriate, by tags attached to the item. Nuclear Generation personnel are notified of any nonconformances identified in accordance with approved procedures.

Nuclear Generation maintains a listing of the status of all nonconformance documents. These reports, when complete, identify the nonconforming material, part or component; applicable inspection requirements; and the resolution, and approval thereof, of the nonconformance. Provisions are established for identifying those personnel with the responsibility and authority for approving the resolution of nonconformances. Until a determination of conformance is made, a nuclear safety related material, part or component cannot be placed in service. Tags which are placed on items to identify nonconformances are removed upon resolution.

Significant trends will be/are reported to appropriate levels of management.

D17.3.2.14 Document Control

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.2.15 Records

To the maximum extent practicable, records are stored such that they are protected from possible destruction by causes such as fire, flooding, theft, insects and rodents and from possible deterioration due to a combination of extreme variations in temperature and humidity conditions.

Record storage areas shall be evaluated by a Fire Protection Engineer (meeting Professional Member grade qualifications of the SFPE) to assure the records are adequately protected from damage. The evaluation shall include the following considerations as a minimum:

a) Structural collapse.
b) Unprotected steel (suspended floor slab or roof).
c) Fire frequency of similar occupancies.
d) Quantities of combustible materials.
e) Ceiling height/Room configuration which would contribute to heat dissipation.
f) Fire detection.
g) Fixed fire suppression systems.
h) On-site firefighting organizations including available equipment.

This evaluation shall be documented for each record storage area.

D17.3.3 SELF ASSESSMENT

D17.3.3.1 Methodology

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.2 Independent Review

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3 Independent Assessment

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.1 Organization

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.2 Internal Assessment Process

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.3 NOS Audit Program

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.3.1 Other Reviews Prescribed by the Code of Federal Regulations

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.3.2 Independent Audit of Fire Protection Program

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.4 Results

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.5 Supplier Oversight

Supplier oversight assures that supplier QA programs provide for surveillance, evaluation, and approval of sub-supplier supplying items and services. This assurance is accomplished through one or more of the following: 1) reviewing supplier audits of sub-supplier as part of the pre-bid audit, 2) making supplier control of sub-supplier work a criterion for supplier approval or disapproval, 3) making supplier surveillance of sub-supplier a requirement of the purchase requisition.

Supplier oversight performs source verification and audits on suppliers' QA programs including the activities of their suppliers and sub-suppliers, to assure that operations are in compliance with specified QA requirements. In the case of an audit of a supplier, any deficiencies noted by the auditor are clearly outlined in writing and given to the supplier's QA organization, which takes appropriate steps to resolve the deficiencies.

A re-audit is performed, if appropriate, to verify the implementation of the corrective action.

D17.3.3.3.6 Independent Audit of QA Functions

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.3.3.7 Audit Frequency Extensions

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4 ADMINISTRATIVE CONTROLS RELOCATED FROM TECHNICAL SPECIFICATIONS

Consistent with NRC Administrative Letter 95-06, certain administrative controls from the original station Technical Specifications have been relocated to the Quality Assurance Program. These relocated administrative controls include technical review, 10 CFR 50.59 review, record retention, and audit requirements. This section identifies those requirements or provides references to the sections of this document where the administrative controls have been integrated with QAP controls.

D17.3.4.1 Technical Reviews

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4.2 10 CFR 50.59 Reviews

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4.3 Record Retention

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4.4 Audit Types and Frequencies

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4.5 On-Site Review Committee

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4.6 Reportable Event Action

There are no Duke Energy Carolinas specific amplifications for this section.

D17.3.4.7 Independent Safety Engineering Group Functions

Technical Specifications for Catawba and McGuire included requirements for Independent Safety Engineering Group functions of improving licensee safety performance and ability to respond to accidents by providing onsite technical support and continuous evaluation and feedback of lessons learned from operating experience. Those requirements were transferred to the this document at Amendment 23. At Amendment 36, the specific requirements for Independent Safety Engineering Group were eliminated based on duplication of functions performed by a combination of different groups through the performance of their normal activities.

Enclosure 6
UFSAR, Revision 29 (Publicly Available Information)

Enclosure 7
UFSAR, Revision 29 (Non-Publicly Available Information)