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Attachments 5B and 11B contain proprietary information.

GNRO-2010/00056

September 8, 2010

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

SUBJECT: License Amendment Request
Extended Power Uprate
Grand Gulf Nuclear Station, Unit 1
Docket No. 50-416
License No. NPF-29

Dear Sir or Madam:

Pursuant to 10 CFR 50.90, Entergy Operations, Inc. (Entergy) on behalf of System Entergy Resources, Inc. and South Mississippi Electric Power Association hereby requests approval of an amendment to the Grand Gulf Nuclear Station, Unit 1 (GGNS) Operating License and Technical Specifications (TS). The proposed change will increase the maximum reactor core power operating limit authorized in the Operating License from 3898 megawatts thermal (MWt) to 4408 MWt. This represents an approximate fifteen percent increase above the original licensed power limit of 3833 MWt. In October 2002, the NRC approved a measurement uncertainty recapture power uprate that resulted in an increase in licensed power to 3898 MWt.

The technical evaluations in support of the proposed power uprate are based on NRC-approved licensing topical report NEDC-33004P-A (commonly called CLTR), *Constant Pressure Power Uprate*, Revision 4. For those topics outside the CLTR approved applicability (e.g., use of GNF2 fuel), the technical evaluations are based on NEDC-32424P-A (commonly called ELTR1), *Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate* and NEDC-32523P-A (commonly called ELTR2), *Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate*.

Attachments 1 through 13 include a description of the proposed changes and supporting documentation. GE-Hitachi Nuclear Energy Americas, LLC (GEH) considers portions of the information provided in support of the proposed license amendment request to be proprietary and therefore exempt from public disclosure pursuant to 10 CFR 2.390. Affidavits for withholding information, executed by GEH, are provided in Attachments 6A and 6B. Therefore, on behalf of GEH, Entergy requests to withhold Attachments 5B and 11B from public disclosure

When Attachments 5B and 11B are removed, the entire letter is non-proprietary.

in accordance with 10 CFR 2.390(b)(1). Non-proprietary and proprietary versions of the Safety Analysis Report for Grand Gulf Nuclear Station Constant Pressure Power Uprate (Attachments 5A and 5B) and the Steam Dryer Evaluation (Attachments 11A and 11B) are included.

As part of the proposed extended power uprate (EPU), Entergy plans to replace the existing analog Average Power Range Monitor (APRM) subsystem of the existing Neutron Monitoring System with the more reliable, digital Nuclear Measurement Analysis and Control (NUMAC) Power Range Neutron Monitoring System (PRNMS). A separate PRNMS LAR was submitted to the NRC on November 3, 2009 based on the current operating conditions and is currently being reviewed by the NRC. The only identified open issues associated with the review of the PRNMS LAR neither impact nor are impacted by EPU considerations. The EPU presumes the approval and implementation of the PRNMS. The TS and TS bases markups for EPU reflect revisions to the proposed PRNMS TS to reflect operation at EPU conditions. A license condition is also proposed to ensure that EPU is not implemented prior to NRC approval of the PRNMS LAR.

The proposed change has been evaluated in accordance with 10 CFR 50.91(a)(1) using criteria in 10 CFR 50.92(c) and it has been determined that this change involves no significant hazards consideration. The bases for these determinations are included in the attached submittal.

The proposed change includes new commitments that are listed in Attachment 14.

Entergy requests approval of the proposed amendment within 14 months of the date of submittal. Once approved, the amendment will be implemented coming out of the Spring 2012 refueling outage. Although this request is neither exigent nor emergency, your prompt review is requested.

The license amendment request is provided in electronic file format on the enclosed discs. One disc contains proprietary information and one disc contains a version of the license amendment request that may be made public.

If you have any questions or require additional information, please contact Jerry Burford at 601-368-5755.

I declare under penalty of perjury that the foregoing is true and correct. Executed on September 8, 2010.

Sincerely,

M. A Krupa

MAK/FGB/dm

Attachments:

1. Analysis of Proposed Operating License and Technical Specification Changes
2. Proposed Operating License and Technical Specification Changes (Mark-up)
3. Changes to Technical Specification Bases Pages – For Information Only
4. Extended Power Uprate Environmental Assessment

5A. Safety Analysis Report for Grand Gulf Nuclear Station Constant Pressure Power Uprate (Non-Proprietary)
5B. Safety Analysis Report for Grand Gulf Nuclear Station Constant Pressure Power Uprate (Proprietary)
6A. GEH Affidavit for Withholding Information from Public Disclosure – Safety Analysis Report
6B. GEH Affidavit for Withholding Information from Public Disclosure – Steam Dryer Evaluation

7. Pressure and Temperature Limits Report
8. List of Planned Modifications
9. Extended Power Uprate Startup Test Plan
10. Vibration Analysis and Testing Program

11A. Steam Dryer Evaluation (Non-Proprietary)
11B. Steam Dryer Evaluation (Proprietary)

12. Grid Stability Evaluation
13. Extended Power Uprate Risk Analysis
14. List of Regulatory Commitments

cc: Mr. Elmo E. Collins, Jr. Regional Administrator, Region IV U. S. Nuclear Regulatory Commission 612 East Lamar Blvd., Suite 400 Arlington, TX 76011-4005	CD provided
U. S. Nuclear Regulatory Commission ATTN: Mr. C. F. Lyon, NRR/DORL (w/2) **ATTN: ADDRESSEE ONLY** ATTN: Courier Delivery Only Mail Stop OWFN/8 B1 11555 Rockville Pike Rockville, MD 20852-2378	CD and hard copy provided
State Health Officer Mississippi Department of Health P. O. Box 1700 Jackson, MS 39215-1700	w/out
NRC Senior Resident Inspector Grand Gulf Nuclear Station Port Gibson, MS 39150	CD provided

Attachment 1

GNRO-2010/00056

Analysis of Proposed Operating License and Technical Specification Changes

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1.0 DESCRIPTION

Entergy Operations, Inc. (Entergy), on behalf of the owners of Grand Gulf Nuclear Station, Unit 1 (GGNS), System Entergy Resources, Inc. and South Mississippi Electric Power Association, requests an amendment to the GGNS Operating License (NPF-29). The proposed changes will revise the Operating License (OL) and Technical Specifications (TS) to support an increase in the maximum reactor core power operating limit authorized in the OL from 3898 megawatts thermal (MWt) to 4408 MWt. This represents an approximate 15 percent increase above the original licensed power limit of 3833 MWt. In October 2002, the NRC-approved a measurement uncertainty recapture power uprate that resulted in an increase in licensed power to the current licensed thermal power (CLTP) level of 3898 MWt.

Supporting documentation for the proposed changes is included in the following attachments:

- Attachment 2 provides a markup of the changes to the GGNS OL and TS for the proposed Extended Power Uprate (EPU). For changes affecting TS 3.3.1.1, the TS markup is based on the Power Range Neutron Monitoring System (PRNMS) license amendment request (LAR) submitted November 3, 2009 (Reference 20). When the PRNMS LAR is approved, appropriate changes to the EPU TS markups will be made if necessary. Analysis supporting the EPU and reflected in the Power Uprate Safety Analysis Report (PUSAR) are based on the installation of PRNMS.
- Attachment 3 provides a markup of the proposed changes to the TS bases for information only. In accordance with GGNS TS 5.5.11, Technical Specifications Bases Control Program, Entergy can implement these changes under 10 CFR 50.59 once this application is approved.
- Attachment 4 provides an environmental assessment of the proposed EPU and was prepared pursuant to 10 CFR 51.41, *Requirement to Submit Environmental Information*.
- Attachment 5A provides the non-proprietary version of the “Safety Analysis Report for Grand Gulf Nuclear Station Constant Pressure Power Uprate” (commonly called PUSAR). This report provides an integrated summary of the results of the safety analyses and evaluations performed that support the proposed increase in the maximum power level. The PUSAR safety evaluation follows the format and guidance outlined in RS-001 (Revision 0), Office of Nuclear Reactor Regulation, *Review Standard for Extended Power Uprates*, (Reference 1) to the extent that the review standard is consistent with the design basis of GGNS. The PUSAR includes the RS-001 regulatory evaluation and conclusion sections, customized to reflect the GGNS design basis. The technical evaluations in the PUSAR are based on NRC-approved licensing topical report NEDC-33004P-A (commonly called CLTR), *Constant Pressure Power Uprate*, Revision 4 (Reference 2). As discussed in the PUSAR, for those topics outside the CLTR approved applicability (e.g., use of GNF2 fuel), the technical evaluations are based on NEDC-32424P-A (commonly called ELTR1), *Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate* (Reference 3) and NEDC-32523P-A (commonly called ELTR2), *Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate* (Reference 4).
- Attachment 5B is the proprietary version of the PUSAR. GEH considers portions of the PUSAR to include proprietary information and therefore exempt from disclosure pursuant to 10 CFR 2.390. An affidavit executed by GEH describing the reason for the

request to withhold the proprietary information is provided in Attachment 6A. Therefore, Entergy requests on behalf of GEH that Attachment 5B be withheld from public disclosure in accordance with 10 CFR 2.390(b)(1).

- Attachment 6A is the GEH Affidavit For Withholding Information from Public Disclosure - Safety Analysis Report supporting Attachment 5B.
- Attachment 6B is the GEH Affidavit For Withholding Information from Public Disclosure – Steam Dryer supporting Attachment 11B.
- Attachment 7 provides the proposed Pressure and Temperature Limits Report (PTLR).
- Attachment 8 is the List of Planned Modifications associated with the EPU project.
- Attachment 9 is the Extended Power Uprate Startup Test Plan.
- Attachment 10 is the Vibration Analysis and Testing Program.
- Attachment 11A provides the non-proprietary version of the Steam Dryer Evaluation. The analysis includes an evaluation of the replacement steam dryer at EPU conditions.
- Attachment 11B provides the proprietary version of the Steam Dryer Evaluation. GEH considers portions of the Steam Dryer Evaluation to include proprietary information and therefore exempt from disclosure pursuant to 10 CFR 2.390. An affidavit executed by GEH describing the reason for the request to withhold the proprietary information is provided in Attachment 6B. Therefore, Entergy requests on behalf of GEH that this attachment be withheld from public disclosure in accordance with 10 CFR 2.390(b)(1).
- Attachment 12 is the Grid Stability Evaluation, which evaluates the impact of the EPU on the transmission system stability.
- Attachment 13 is a report of the Extended Power Uprate Risk Analysis.
- Attachment 14 provides a List of Regulatory Commitments associated with the EPU.

2.0 PROPOSED CHANGE

2.1 Operating License and Technical Specifications

The following OL and TS sections, and associated TS bases, are affected by the proposed EPU:

- Operating License Paragraph 2.C.(1) and the addition of new license conditions
- Definitions - Rated Thermal Power (RTP) and a new definition for Pressure and Temperature Limits Report (PTLR)
- Thermal Power Limit with Low Dome Pressure or Low Core Flow (TS 2.1.1.1)
- Minimum Critical Power Ratio (MCPR) Safety Limit (TS 2.1.1.2)
- Standby Liquid Control (SLC) System (TS 3.1.7)
- Average Planar Linear Heat Generation Rate (APLHGR) (TS 3.2.1)
- Minimum Critical Power Ratio (MCPR) (TS 3.2.2)

- Linear Heat Generation Rate (LHGR) (TS 3.2.3)
- Reactor Protection System (RPS) Instrumentation (TS 3.3.1.1)
- End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation (TS 3.3.4.1)
- Primary Containment and Drywell Isolation Instrumentation (TS 3.3.6.1)
- Jet Pumps (TS 3.4.3)
- Safety / Relief Valves (TS 3.4.4)
- Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits (TS 3.4.11)
- Main Turbine Bypass System (New TS 3.7.7)
- RCS Pressure and Temperature Limits Report (PTLR) (New TS 5.6.6)

A detailed discussion of each change is included in Section 4.0 of this Attachment. Markups of the OL and TS reflecting the proposed changes are provided in Attachment 2. Associated changes to the TS Bases are provided in Attachment 3.

Many of the TS listed above contain criteria or requirements expressed in terms of percent rated thermal power (% RTP) that are re-scaled or otherwise adjusted for EPU. However, there are several other TS with such criteria that do not require revision to support EPU. To avoid any misunderstanding, these TSs are discussed below with a brief explanation as to why a revision is unnecessary.

1. <u>Control Rod Operability (TS 3.1.3)</u>

   The current TS Action D includes a note stating the Action is not applicable when thermal power is greater than 10% RTP. The stated RTP is conservatively maintained at the same percent RTP as CLTP. The 10% value, which is an allowable value (AV) derived from turbine first stage pressure, is the Rod Control and Information System (RCIS) Rod Pattern Controller (RPC) low-power setpoint (LPSP). The EPU analytical limit (AL) for the LPSP is 8% RTP. As such the current AV continues to protect the EPU AL. See PUSAR Section 2.4.1.3.4 and Table 2.4-1.

2. <u>Control Rod Scram Times (TS 3.1.4)</u>

   Surveillance requirements (SR) 3.1.4.1 and 3.1.4.4 require verification of control rod scram time is within applicable limits prior to exceeding 40% RTP. The stated % RTP does not change. The control rod scram time test is a timing consideration in that it should be performed as soon as practicable to minimize the impact on plant operation. Testing prior to 40% EPU RTP does not affect the operation or operability of the control rods.

3. Control Rod Pattern (TS 3.1.6)

   This TS is applicable in Modes 1 and 2 with thermal power less than or equal to 10% RTP. The stated RTP is being conservatively maintained at the same percent RTP as CLTP. The 10% value, which is an AV derived from turbine first stage pressure, is the RCIS RPC LPSP. The EPU AL for the LPSP is 8% RTP. As such the current AV continues to protect the EPU AL. See PUSAR Section 2.4.1.3.4 and Table 2.4-1.

4. Reactor Protection System (RPS) Instrumentation (TS 3.3.1.1)

   Table 3.3.1.1-1, Allowable Value for Neutron Flux – High, Setdown (APRM Function 2.a) – the stated % RTP does not change. No specific safety analyses take credit for this function, which indirectly ensures reactor power does not exceed 21.8% RTP before the Mode Switch is placed in “RUN.” Since the current allowable value (≤ 20% RTP) is less than 21.8% RTP no change is required. See PUSAR Section 2.4.1.3.6.

5. Control Rod Block Instrumentation (TS 3.3.2.1)

   - SR 3.3.2.1.2 requires the performance of the Control Rod Block Instrumentation Channel Functional Test, with an allowance to delay the performance until 1 hour after thermal power is greater than 35% RTP and less than or equal to the Rod Withdrawal Limiter (RWL) High Power Setpoint (HPSP). The % RTP is unchanged in terms of percent power (% RTP) for EPU. Maintaining this value provides a reasonable time for testing to be completed and does not affect the operation or operability of the control rod block instrumentation.
   - SRs 3.3.2.1.3 and 3.3.2.1.4 require the performance of a Control Rod Block Instrumentation Channel Functional Test, with an allowance to delay the performance until one hour after any control rod has been withdrawn when RTP is less than or equal to 10% RTP. The stated RTP is being conservatively maintained at the same percent RTP as CLTP. The 10% value, which is an AV derived from turbine first stage pressure, is the RCIS RPC LPSP. The EPU AL for the LPSP is 8% RTP. As such the current AV continues to protect the EPU AL. See PUSAR Section 2.4.1.3.4 and Table 2.4-1.
   - SR 3.3.2.1.5 requires the calibration of the LPSP trip units and states that the AV shall be greater than or equal to 10% RTP and less than or equal to 35% RTP. The current lower AV (10%) protects the EPU AL of 8% RTP. The current upper AV (35%) protects the EPU AL of 36% RTP. Maintaining these values at the same percent RTP as CLTP is conservative. See PUSAR Section 2.4.1.3.4 and Table 2.4-1.
   - SR 3.3.2.1.6 requires verification that the RWL high power function is not bypassed when thermal power is greater than 70% RTP. The stated % RTP, which is an analytical limit, is unchanged as a result of EPU. See PUSAR Table 2.4-1.
   - Table 3.3.2.1-1 note (b) states that the RWL function shall be operable when thermal power is greater than 35% RTP. The EPU AL for this value is 36% RTP. The current AV (35%) is conservative and continues to protect the EPU AL.
   - Table 3.3.2.1-1 note (c) states that the RPC function shall be operable when thermal power is less than or equal to 10% RTP. The EPU AL for this value is

8% RTP. Maintaining the stated % RTP, which is the AV, at the current CLTP value is conservative and continues to protect the EPU AL.

6. Reactor Coolant System Pressure and Temperature (P/T) Limits (TS 3.4.11)

   SRs 3.4.11.8 and 3.4.11.9 are required when in single loop operations with thermal power less than 36% RTP and during increases in thermal power or recirculation loop flow with the operating recirculation pump not on high speed, respectively. Test data has demonstrated that temperature stratification in the lower head is not expected at power levels greater than 36%. Maintaining 36% RTP is conservative and results in monitoring differential temperatures at a higher absolute thermal power level when in single loop operation.

7. Suppression Pool Average Temperature (TS 3.6.2.1)

   The Limiting Condition for Operation (LCO), Conditions, and Required Actions include reference to 1% RTP. This value does not change. Heat input at 1% RTP is approximately equal to normal system heat losses; therefore this % RTP value is acceptable without change.

2.2 Technical Specification Bases Changes

Markups of the changes to the TS Bases are included in Attachment 3. Changes to the affected TS bases, which are controlled using the TS Bases Control Program (TS 5.5.11), are provided for information only. The markups include the changes associated with the TS changes that are discussed in Section 4.1. In addition, the following TS Bases changes, which are also included in Attachment 3, support changes that do not require changes to the associated TS:

1. TS 2.1.1.1 bases includes a discussion of the ATLAS test data taken at pressures from 14.7 psia to 800 psia that indicates the fuel assembly critical power at the specified bundle flow is approximately 3.35 MWt. With the design peaking factors, the fuel assembly critical power correspondences to a thermal power value of greater than 50% RTP. This % RTP is being revised to 44.2% RTP to maintain the same absolute thermal power level (i.e., 50% x (3898 MWt / 4408 MWt) = 44.2%).

2. The bases of TS 3.3.6.1, “Primary Containment and Drywell Isolation Instrumentation” describes how Table 3.3.6.1-1, Function 1.b, Main Steam Line Pressure – Low, ensures Safety Limit TS 2.1.1.1 is not exceeded. This is accomplished by closing the Main Steam Isolation Valves (MSIVs) prior to pressure decreasing below 785 psig, which results in a scram due to MSIV closure, thus reducing reactor power to < 25% RTP. The referenced steam dome pressure and % RTP are being changed to be consistent with the proposed change to TS 2.1.1.1.

3. TS Bases for TS 3.6.1.1, “Primary Containment,” TS 3.6.1.2, “Primary Containment Air Locks,” and TS 3.6.1.3, “Primary Containment Isolation Valves” are being revised to reflect an increase in the peak containment pressure (Pa) from the current value of 11.5 psig to 11.9 psig. As noted in PUSAR Table 2.6-1, “GGNS Containment Performance Results,” the EPU design basis accident (DBA) loss of coolant accident (LOCA) new long-term

pressure, which is driven by the main steam line break, results in peak containment pressure of 11.9 psig occurring at about 10 hours after the event.

The short-term wet well pressure can reach 14.8 psig. This pressure will be terminated in about 6 seconds after the event and occurs in a localized area of containment and is therefore not representative of containment bulk pressure. Table 4, "LOCA Release Phases," of Regulatory Guide 1.183, Rev. 0, *Alternate Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors*, shows that the Boiling Water Reactor (BWR) core source terms do not begin to be released from the reactor vessel until 2 minutes after a LOCA. The only radioactivity released from the reactor during the first 6 seconds is associated with the reactor coolant. This release is very small and scrubbed by the suppression pool before exhausting into the region between the pool and the hydraulic control unit (HCU) floor. Considering the primary containment function is to mitigate radioactivity leakage, the impact of any additional leakage rate associated with this early period would be negligible due to its low source term.

4. The bases for TS 3.6.2.3, "Residual Heat Removal (RHR) Suppression Pool Cooling," list the peak suppression pool temperature as 185°F. For EPU implementation this design limit will be changed to 210°F. Refer to PUSAR Section 2.6.1.1.1.

5. The bases for TS 3.6.3.3, "Drywell Purge System," will be revised to reflect that the diluting function of the drywell purge compressors will be credited in the EPU equipment qualification analysis.

6. The bases for SR 3.6.5.1.1 specifies that the actual drywell bypass leakage is less than or equal to the acceptable $A/\sqrt{K}$ design value of 0.9 square feet. A steam bypass analysis was performed to establish the maximum allowable effective steam bypass area with EPU conditions. The analysis determined that an effective steam bypass area should be limited to 0.8 square feet to maintain the peak calculated containment pressure within the design limit with EPU conditions. The discussion in the Applicable Safety Analyses of TS Bases 3.6.1.7, "RHR Containment Spray System," and the discussion of Action A.1 of TS Bases 3.6.5.6, "Drywell Vacuum Relief System," also reference the design bypass leakage and will be changed.

2.3 Methodology Changes

In support of the power uprate, re-evaluation of the annulus pressurization loads associated with the current licensing basis was performed using new methodologies for GGNS. For more information refer to Section 4.3.1 of this Attachment.

A different methodology was also used to perform the long-term containment analysis, which is described in more detail in Section 4.3.2 of this Attachment.

Also in support of the power uprate, an evaluation of the new steam dryer was required. The evaluation was performed using a plant based load evaluation (PBLE) method, which is a new methodology for GGNS. Refer to Attachments 11 A / B.

In summary, the proposed changes to the OL, TS and associated TS Bases, which are described in more detail in Section 4.0, support an increase in the authorized maximum reactor core power operating limit to 4408 MWt.

3.0 BACKGROUND

Power Uprate Safety Analysis Report

Licensing topical report NEDC-33004P-A, *Constant Pressure Power Uprate*, Revision 4, dated July 2003 (Reference 2), commonly called the CLTR, provides an NRC-accepted approach for performing constant pressure power uprates (CPPU). The CPPU approach has been used as the basis of multiple power uprate license amendment requests submitted to and approved by the NRC. As the name suggests, the CPPU approach maintains a plant's current maximum operating reactor pressure. The constant pressure constraint, along with other required limitations and restrictions discussed in the CLTR, allows a simplified approach to power uprate analyses and evaluations.

The evaluation methods and conclusions of NEDC-33004P-A (Reference 2) were approved for GE fuel up through GE14 fuel. Since GGNS utilizes GNF2 fuel, certain evaluations and conclusions of the CLTR are not applicable for fuel design-dependent evaluations at GGNS. Therefore, for fuel-dependent topics, the guidance in NRC-approved NEDC-32424P-A (Reference 3) commonly called ELTR1 was used. Safety issues identified in ETLR1 that should be addressed in a plant-specific EPU license amendment request are addressed in the PUSAR. For issues that have been evaluated generically, the PUSAR references the NRC-approved generic evaluations in either ELTR1 or NEDC-32523P-A (Reference 4), which is commonly called ELTR2.

The Office of Nuclear Reactor Regulation document, *Review Standard for Extended Power Uprates*, RS-001, Revision 0, dated December 2003 (Reference 1), provides guidance to the NRC Staff when performing reviews of EPU applications. The review standard was developed to enhance the consistency, quality, and completeness of the Staff's reviews and to inform licensees of the guidance documents the Staff would use when reviewing EPU applications. These documents provide the acceptance criteria for the areas of review allowing licensees to prepare EPU applications that are complete with respect to the areas that are within the Staff's scope of review. Section 3.2 of RS-001, *Template Safety Evaluation for Boiling-Water Reactor Extended Power Uprate*, Inserts 1-13, provides the Staff an outline to follow when generating plant-specific safety evaluations. For each area of concern, a Regulatory Evaluation and Conclusion statement is provided. As noted in RS-001, the use of this review standard was not intended to undermine the NRC's topical report review and approval process. If a licensee references an NRC-approved topical report for an area covered by RS-001, the Staff will review the application only to ensure that the licensee is applying the topical report under conditions for which the topical report was approved, using appropriate plant-specific inputs.

NEDO-33477, *Safety Analysis Report for Grand Gulf Nuclear Station Constant Pressure Power Uprate*, (also called the PUSAR) is provided in Attachments 5A (non-proprietary version) and 5B (proprietary version). This report provides an integrated summary of the results of the safety analyses and evaluations performed in accordance with NEDC-33004P-A (Reference 2), NEDC-32424P-A (Reference 3), and NEDC-32523P-A (Reference 4). These analyses and evaluations support the proposed increase to the maximum power level at GGNS to 4408 MWt. The PUSAR, Section 2, Safety Evaluation, follows the format and guidance delineated in RS-001, Section 3.2, to the extent that the review standard is consistent with the GGNS design basis. Differences between the plant-specific design basis and RS-001 Regulatory Evaluations are described and evaluations provided.

In summary, the PUSAR Technical Evaluations are based on NRC-approved topical reports CLTR, ELTR1, and ELTR2 (References 2, 3, and 4) and their associated NRC Safety Evaluation Reports.

GGNS is currently licensed to operate for an 18-month fuel cycle. The fuel-related plant-specific analyses reflected in the PUSAR have been performed considering a 24-month fuel cycle. This assumption lead to the use of a conservative equilibrium core representative of GGNS design for operation at EPU thermal power in the EPU safety and radiological analyses. Following approval of the EPU license amendment request, GGNS plans to submit a request to extend the fuel cycle to 24 months.

4.0 TECHNICAL ANALYSIS

4.1 Operating License and Technical Specifications Changes

The following OL and TS changes are required to support EPU.

4.1.1 Operating License Paragraph 2.C.(1)

The proposed change supports an increase in the authorized maximum reactor core power operating limit from 3898 megawatts thermal (MWt) to 4408 MWt. This change is justified based on the analyses and evaluations presented in this license amendment request.

4.1.2 Operating License – New Conditions

Leak Rate Testing

Surveillance Requirements 3.6.1.1.1, 3.6.1.3.5, and 3.6.1.3.9 require performance of leak rate testing in accordance with the 10 CFR 50, Appendix J Testing Program (TS 5.5.12). Test intervals are established on a performance basis in accordance with 10 CFR 50, Appendix J, Option B. The Type A integrated leakage rate test (ILRT) and the Type B and C local leakage rate tests are performed at pressures based on accident conditions calculated for EPU. The analyzed peak containment pressure, which is driven by the main steam line break, is 11.9 psig. The change to calculated peak containment pressure (Pa) is described in the proposed change to the TS bases in Section 2.2.

Surveillance Requirements 3.6.5.1.1 and 3.6.5.1.2 require performance of the drywell bypass leakage test. These SRs are performed at 10 year intervals and are coordinated with the performance of the ILRT. The test verifies that drywell bypass leakage is less than or equal to 10% of the A/√K design value of 0.9 square feet. As described above, this value, based on steam bypass analysis, should be limited to 0.8 square feet to maintain the peak calculated containment pressure within the design limit with EPU conditions.

Entergy proposes a new license condition to defer performing these SRs until the next scheduled performance date for each SR. The proposed License Condition will allow leakage rate tests required by SRs 3.6.1.1.1, 3.6.1.3.5, 3.6.1.3.9, 3.6.5.1.1, and 3.6.5.1.2 to be performed as currently scheduled. The proposed License Condition will allow these SRs to be considered to be performed per SR 3.0.1 until the next scheduled performance. The following License Condition is proposed:

> "Leak rate tests associated with Surveillance Requirements (SR) 3.6.1.1.1, 3.6.1.3.5, and 3.6.1.3.9, as required by TS 5.5.12 and in accordance with 10 CFR 50, Appendix J, Option B, and SRs 3.6.5.1.1and 3.6.5.1.2 are not required to be performed until their next scheduled performance dates. The tests will be performed at the EPU calculated long-term peak containment pressure or within EPU drywell bypass leakage limits, as appropriate."

Since there is substantial margin to the leakage rate acceptance limits for containment and drywell bypass based on current leakage rate testing results, it is not necessary to re-perform all of the leakage rate tests at the new limits before implementation of the EPU.

Power Range Neutron Monitoring System

A new License Condition is proposed to ensure NRC approval of the PRNMS LAR (Reference 20) is obtained prior to increasing power above 3,898 MWt (CLTP). The proposed License Condition is:

> "EOI will not operate GGNS at a thermal power level above 3,898 MWt until the Power Range Neutron Monitoring System license amendment request is approved by the NRC."

While Entergy anticipates the PRNMS LAR will be approved prior to EPU LAR approval, the proposed license condition supports concurrent review of the two submittals.

4.1.3 Definitions - Rated Thermal Power

The proposed change will revise the definition of rated thermal power from the current value of 3898 MWt to 4408 MWt. This change is administrative in nature and is reflective of the OL change discussed in 4.1.1.

4.1.4 Definitions - Pressure and Temperature Limits Report (PTLR)

Evaluations performed in support of EPU identified that the Pressure Temperature (P/T) limits should be changed (refer to PUSAR Section 2.1.2). Entergy proposes to implement the new limits in the Pressure Temperature Limits Report (PTLR). For a discussion of the new limits and their impact on current TS 3.4.11 see Section 4.1.15

and for a discussion of the new administrative TS that implements the PTLR see Section 4.1.17.

The proposed change adds the definition of the PTLR. This change supports deleting TS Figure 3.4.11-1, the RCS Pressure / Temperature (P/T) curves, and including revised curves in the PTLR. The change is consistent with the wording in Revision 3.1 of NUREG-1434, *Standard Technical Specifications, General Electric Plants, BWR/6* (Reference 5), which reflects Technical Specification Task Force (TSTF) 419-A, *Revise PTLR Definition and References in ISTS 5.6.6, RCS PTLR* (Reference 6). NRC Generic Letter (GL) 96-03, *Relocation of the Pressure Temperature Limit Curves and Low Temperature Overpressure Protection System Limits* (Reference 7) provides guidance that allows the relocation of the RCS P/T curves to a PTLR.

4.1.5 <u>Thermal Power Limit with Low Dome Pressure or Core Flow (TS 2.1.1.1) and MCPR (TS 2.1.1.2)</u>

The current TS states that thermal power shall be less than or equal to 25% RTP when the reactor steam pressure is less than 785 psig or core flow is less than 10% rated core flow. The proposed change will revise the % RTP to 21.8% RTP. The revision to the % RTP is based on the fuel thermal monitoring threshold. Refer to PUSAR Section 2.8.2.1.2.

In March 2005, GE Energy–Nuclear issued a 10 CFR Part 21 communication regarding the potential for BWRs to experience reactor pressure below the low pressure Safety Limit of 785 psig defined in TS 2.1.1.1 under certain transient conditions. As documented in Safety Communication 05-03, *Potential to Exceed Low Pressure Technical Specification Safety Limit*, depressurization transients, such as the Pressure Regulator Failure-Maximum Demand Open (PRFO), could cause the reactor steam dome pressure to decrease to below 785 psig for a few seconds while thermal power exceeds 25% of rated power.

In July 2006, the BWR Owners' Group proposed to address this issue with a change to the Technical Specification Bases (TSTF-495) indicating that TS 2.1.1.1 is not applicable to depressurization transients, such as PRFO, that may result in momentarily decreasing below 785 psig with power above 25% (ML061990227). The NRC subsequently rejected this proposed TSTF indicating that the Bases is not the appropriate location for an exception to an explicit safety limit (ML072340113).

GGNS is affected by this 10 CFR Part 21 notification. To facilitate the closure of this issue, GGNS proposes a change to TS 2.1.1.1 to reduce steam dome pressure from 785 psig to 685 psig, thereby significantly reducing the likelihood of a depressurization transient resulting in a power-pressure profile that exceeds the safety limit in TS 2.1.1.1. The reduction in dome pressure is consistent with that used in the NRC-approved critical power correlations for the GE14 and GNF2 fuel designs:

- NEDC-32851P-A, Rev. 4, *GEXL14 Correlation for GE14 Fuel*
- NEDC-33292P-A, Rev. 3, *GEXL17 Correlation for GNF2 Fuel*

Consistent with the above proposed change to the steam dome pressure in TS 2.1.1.1, the steam dome pressure listed in TS 2.1.1.2 will also be revised to 685 psig.

4.1.6 Standby Liquid Control (SLC) System (TS 3.1.7)

The EPU analysis identified one change associated with SLC related to pump discharge pressure. SR 3.1.7.7 currently verifies that each pump develops a flow rate ≥ 41.2 gpm at a discharge pressure of ≥ 1300 psig. The stated discharge pressure is being changed from ≥ 1300 psig to ≥ 1340 psig. Refer to PUSAR Section 2.8.4.5.2.

In order to ensure appropriate margins can be maintained during reload design for future cycles, the sodium pentaborate enrichment of Boron-10 solution is being increased. The proposed change continues to ensure the 10 CFR 50.62 boron injection equivalency requirement of 86 gpm is satisfied. Refer to PUSAR Sections 2.8.4.5 and 2.8.5.7.

The following changes are proposed to support margin restoration:

- Action A Condition and Required Action A.1 are being revised to reflect the new (C)(E). The proposed (C)(E) of 420 provides margin to the (C)(E) needed to ensure the reactor can be shutdown from rated power conditions to cold shutdown in the event some or all of the control rods cannot be inserted. The Completion Time is being changed to "8 hours," which is consistent with the Completion Time allowed for the restoration of one SLC subsystem when two SLC subsystems are inoperable. The proposed changes support the increase in the sodium pentaborate solution and impose a more restrictive Completion Time than currently required.
- Existing Action B Condition and Required Action B.1 are being renumbered as Action D and Required Action D.1.
- Existing Action C Condition and Required Action C.1 are being renumbered as Action E and Required Action E.1.
- Existing Action D Condition and Required Action D.1 are being renumbered as Action F and Required Action F.1.
- New Action B Condition and Required Action B.1 are being added to address the sodium pentaborate volume. Maintaining the SLC tank with (C)(E) of greater than or equal to 420 and a volume of greater than or equal to 4,200 gallons ensures that, upon completion of injection, the reactor vessel is subcritical. A Completion Time of "8 hours," which is consistent with the Completion Time allowed for the restoration of one SLC subsystem when two SLC subsystems are inoperable, is proposed. An evaluation was performed to demonstrate that (C)(E)>420 with at least 4200 gallons provides an acceptable shutdown margin in the event of an Anticipated Transient Without Scram (ATWS).
- New Action C Condition and Required Action C.1 are being added to address the sodium pentaborate temperature. The lower temperature provides margin to the sodium pentaborate saturation temperature and precludes precipitation. The upper temperature limit ensures adequate net positive suction head requirements for two pump operation. A Completion Time of "8 hours," which is consistent with the Completion Time allowed for the restoration of one SLC subsystem when two SLC subsystems are inoperable, is proposed.
- Renumbered Actions D and E are being revised to address inoperable conditions other than Conditions A, B and C.

The following Surveillance Requirements (SRs) will also be modified:

- SR 3.1.7.1 is being revised to verify the available volume of sodium pentaborate solution is greater than or equal to 4,200 gallons. This change results in the deletion of Figure 3.1.7-1. Performance of this SR ensures adequate sodium pentaborate volume is available to inject into the reactor vessel if required.
- SR 3.1.7.2 is being revised to verify the temperature of sodium pentaborate solution is greater than or equal to 45°F and less than or equal to 150°F. This change results in the deletion of Figure 3.1.7-2. Performance of this SR ensures the temperature of sodium pentaborate in the tank and at the pump suction piping (current SR 3.1.7.3) is within specified limits to ensure the capability of the system to inject the boron solution into the reactor vessel if required. The less restrictive lower temperature requirement prevents precipitation considering the reduced concentration requirements in accordance with the sodium pentaborate saturation curve. The upper temperature limit ensures adequate net positive suction head requirements for two pump operation.
- SR 3.1.7.3 is being deleted and incorporated in proposed SR 3.1.7.2. A new SR 3.1.7.3 requires verification that (C)(E) is greater than or equal to 420. A new note is being added to address the association of SRs 3.1.7.5 and 3.1.7.9 to this SR. Because of the relatively slow variation in boron concentration a Frequency of 31 days is proposed.
- SR 3.1.7.5 is being revised to verify the percent weight concentration of sodium pentaborate solution is less than or equal to 9.5%. The temperature listed in the Frequency associated with performing the SR anytime the solution low temperature is restored to within limits is being revised to greater than or equal to 45°F. The change in temperature is consistent with the proposed operating temperature band. Performance of the SR after the temperature is restored will ensure that no significant boron precipitation occurred while the temperature was less than 45°F.
- SR 3.1.7.9 is being deleted and replaced with a requirement to determine the boron-10 (B-10) enrichment once within 24 hours after boron is added to the solution. Enriched sodium pentaborate solution is made by mixing granular, enriched sodium pentaborate with water. Isotopic tests on the sodium pentaborate solution to determine the actual B-10 enrichment must be performed within 24 hours after boron is added to the solution in order to ensure the B-10 enrichment is adequate.

In addition to the above, Figures 3.1.7-1 and 3.1.7-2 will be deleted. A note will be added to page 3.1-23 stating that the next page is 3.1-26. This is an administrative change and allows the current TS page numbering to remain the same.

The new Actions and SRs ensure that the volume of sodium pentaborate solution available for injection and the concentration of sodium pentaborate in the solution provide the negative reactivity required to shutdown the reactor and compensate for the positive reactivity effects due to temperature decrease and xenon decay during cooldown.

The function of the SLC system, method of operation, redundancy and system configuration remain unchanged as a result of the proposed changes.

4.1.7 Average Planar Linear Heat Generation Rate (APLHGR) (TS 3.2.1)

TS 3.2.1, APLHGR Applicability, Action B.1, and SR 3.2.1.1 Frequency include requirements associated with a thermal power limit of 25% RTP. The proposed change will revise the % RTP to 21.8% RTP. The revision to the % RTP is based on the fuel thermal monitoring threshold (refer to PUSAR Section 2.8.2.1.2).

4.1.8 Minimum Critical Power Ratio (MCPR) (TS 3.2.2)

TS 3.2.2, MCPR Applicability, Action B.1, and SR 3.2.2.1 Frequency include requirements associated with a thermal power limit of 25%. A change is proposed to revise the % RTP to 21.8% RTP. The revision to the % RTP is based on the fuel thermal monitoring threshold (refer to PUSAR Section 2.8.2.1.2).

In addition to the above and in order to maintain operating margin in future cycle-specific core design evaluations and address the expected increase in scram times, a new SR 3.2.2.2 is being added to allow the determination of the operating limit MCPR based on the scram time testing results (i.e., Option B). Refer to PUSAR Section 2.8.4.1.1. The new SR will require determination of the MCPR limits:

- Once within 72 hours after each completion of SR 3.1.4.1, which provides verification that each control rod scram time is within specified TS limits; and
- Once within 72 hours after each completion of SR 3.1.4.2, which provides verification that a representative sample of each tested control rod scram time is within the defined TS limits; and
- Once within 72 hours after each completion of SR 3.1.4.4, which provides verification of the control rod scram time after work has been performed on the control rod or control rod drive that could affect the scram time.

Currently GGNS utilizes the Option A MCPR operating limits. Use of the Option A methodology limits the severity of the operating limits for pressurization events such that non-pressurization events become limiting. As a method to recognize the significant margin typically observed in scram time testing and to improve operating limits, plants have credited the application of a mean scram speed based operating limit (Option B). The Option B basis does not require any additional scram speed data beyond what is required by TS 3.1.4, “Control Rod Scram Times,” since the mean scram speed is based on the measured scram speed.

Since transient analyses may take credit for conservatism in the control rod scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analyses. The proposed SR determines the actual scram speed distribution and compares it with the assumed distribution. The MCPR operating limit is then determined based either on the applicable limit associated with TS 3.1.4 or the realistic scram times. This determination must be performed and any necessary changes must be implemented within 72 hours after each set of control rod scram time tests required by SRs 3.1.4.1, 3.1.4.2, and 3.1.4.4 because the effective scram speed distribution may change during the cycle or after maintenance that could affect scram times. The 72 hour Completion Time is acceptable due to the relatively minor changes in the actual control rod scram speed distribution expected during the fuel cycle.

The function of the MCPR operating limit is to ensure that no fuel damage occurs during anticipated operational occurrences. This function is met using either Option A or Option B to determine the MCPR operating limit.

Use of the Option B analysis allows credit for actual faster scram speeds to provide for a lower MCPR operating limit. This lower operating limit ensures that the MCPR safety limit is not exceeded while providing for additional operating margin.

The methodology for use of Option A and Option B limits is included in NEDE-24011P-A (commonly called GESTAR II), *General Electric Standard Application for Reactor Fuel*, (Reference 9), which is referenced in the GGNS Core Operating Limits Report (COLR) and used by GGNS. Consistent with the current LCO, the MCPR operating limits associated with Options A and B will be included in the COLR.

4.1.9 <u>Linear Heat Generation Rate (LHGR) (TS 3.2.3)</u>

TS 3.2.3, LHGR Applicability, Action B.1, and SR 3.2.3.1 Frequency include requirements associated with a thermal power limit of 25% RTP. The proposed change will revise the % RTP to 21.8% RTP. The revision to the % RTP is based on the fuel thermal monitoring threshold (refer to PUSAR Section 2.8.2.1.2).

4.1.10 <u>Reactor Protection System (RPS) Instrumentation (TS 3.3.1.1)</u>

The following Actions and SRs are being revised to support the EPU.

- Action E – the stated % RTP is being changed from the stated analytical limit of 40% RTP to 35.4% RTP. Rescaling the % RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP (refer to PUSAR Table 2.4-1).
- Action F – the stated % RTP is being changed from 25% RTP to 21.8% RTP. The revision to the % RTP is based on the fuel thermal monitoring threshold (refer to PUSAR Section 2.8.2.1.2).
- Action K – the stated % RTP is being changed from 24% RTP to 21% RTP. The change is required to be 5% less than the Oscillation Power Range Monitor (OPRM) trip enabled region boundary (see proposed change to SR 3.3.1.1.23). This change is based on the TS markups submitted as part of the PRNMS LAR (Reference 20).
- SR 3.3.1.1.2 – the stated % RTP of 25% in the Note and % RTP in the SR are being changed to 21.8% RTP. The revision to the % RTP is based on the fuel thermal monitoring threshold (refer to PUSAR Section 2.8.2.1.2).
- SR 3.3.1.1.14 – the stated % RTP is being changed from the stated analytical limit of 40% RTP to 35.4% RTP. Rescaling the % RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP (refer to PUSAR Table 2.4-1).
- SR 3.3.1.1.23 – the stated % RTP is being changed from 29% RTP to 26% RTP. Rescaling the % RTP maintains TS Applicability at its same absolute thermal power level that was evaluated for the new PRNMS (refer to PUSAR Section 2.8.3). This

change is based on the TS changes submitted as part of the PRNMS LAR (Reference 20).

- Table 3.3.1.1-1, Allowable Value for Fixed Neutron Flux – High (Function 2.b) stated allowable value in % RTP is being changed from 120% to 119.3% RTP. The change ensures that adequate operating margin is maintained between the system setting and the analytical limit (122% RTP) (refer to PUSAR Table 2.4-1).
- Table 3.3.1.1-1, Function 2.d, APRM Flow Biased Simulated Thermal Power – High, note (b) is being changed to:

  "Two-Loop Operation: 0.58W + 59.1% RTP and ≤113% RTP
  Single-Loop Operation: 0.58W + 37.4% RTP"

  "W" is the total recirculation drive flow in percent of rated flow. The change rescales the allowable value based on the proposed changes in power level. This change updates the TS changes submitted as part of the PRNMS LAR (Reference 20) to reflect EPU conditions.
- Table 3.3.1.1-1, Function 2.f., OPRM Upscale Applicable Mode is being changed from the existing value of 24% RTP to 21%. The change supports the requirement for the value to be 5% less than the OPRM trip enabled region boundary (see proposed change to SR 3.3.1.1.23). This change updates the TS changes submitted as part of the PRNMS LAR (Reference 20) to reflect EPU conditions.
- Table 3.3.1.1-1, Function 5, Reactor Vessel Water Level – High, Level 8, is required to be met when the % RTP is ≥ 25% RTP. The proposed change revises the % RTP to ≥ 21.8% RTP. The revision to the % RTP is based on the fuel thermal monitoring threshold (refer to PUSAR Section 2.8.2.1.2).
- Table 3.3.1.1-1, Function 9, Turbine Stop Valve Closure, Trip Oil Pressure – Low Applicable Mode is being changed from the stated analytical limit of ≥ 40% RTP to ≥ 35.4% RTP. Rescaling the % RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP.
- Table 3.3.1.1-1, Function 10, Turbine Control Valve Fast Closure, Trip Oil Pressure – Low Applicable Mode is being changed from the stated analytical limit of ≥ 40% RTP to ≥ 35.4% RTP. Rescaling the % RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP.

4.1.11 <u>End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation (TS 3.3.4.1)</u>

The proposed change revises the % RTP in the following sections of TS 3.3.4.1 from 40% RTP to 35.4% RTP.

- Applicability for TS 3.3.4.1 requires thermal power to be ≥ 40% RTP.
- Action C.2 requires thermal power to be reduced to less than 40% RTP.
- SR 3.3.4.1.5 requires verification that the Turbine Stop Valve Closure, Trip Oil Pressure – Low and Turbine Control Valve Fast Closure, Trip Oil Pressure – Low Functions are not bypassed when thermal power ≥ 40% RTP.

Rescaling the % RTP maintains the same absolute thermal power level that was evaluated and authorized for CLTP.

4.1.12 Primary Containment and Drywell Isolation Instrumentation (TS 3.3.6.1)

Table 3.3.6.1-1 Function 1.c., Main Steam Line Flow – High Allowable Value will be revised from 176.5 psid to 255.9 psid. The change ensures that adequate operating margin is maintained between the system setting and the analytical limit. Refer to PUSAR Section 2.4.1.3.1.

4.1.13 Jet Pumps (TS 3.4.3)

SR 3.4.3.1 Note 2 – the stated % RTP in the note will be changed from > 25%RTP to > 21.8% RTP. The revision to the % RTP is conservative, providing consistency with the other proposed changes to 25% RTP that are associated with the fuel thermal monitoring threshold (refer to PUSAR Section 2.8.2.1.2).

4.1.14 Safety / Relief Valves (TS 3.4.4)

The current LCO states that the safety relief function of seven safety / relief valves (S/RVs) shall be operable. The proposed change will require the safety relief function of nine SRVs to be operable. The basis for the S/RV requirements is the closure of all main steam line isolation valves followed by a reactor scram on high neutron flux (MSIVF) event. The proposed change increases the total number of required SRVs from 13 to 15 to ensure reactor pressure remains below the ASME Service Level C limit of 120% of vessel design pressure (120% x 1250 psig = 1500 psig) during the most limiting ATWS event. Refer to PUSAR Section 2.8.5.7.1 and Table 2.8-8.

4.1.15 RCS Pressure and Temperature (P/T) Limits (TS 3.4.11)

Evaluations performed in support of EPU identified that the P/T limits should be changed (refer to PUSAR Section 2.1.2). Entergy proposes to implement the new limits in the PTLR.

Along with the incorporation of new curves, Entergy proposes the deletion of Figure 3.4.11-1, the P/T limits curves, based on the creation of the PTLR. NRC GL 96-03 (Reference 7) provides guidance that allows the relocation of the RCS P/T curves to a PTLR. The proposed PTLR adopts the methodology described in NRC-approved NEDC-33178P-A, Revision 1, *GE Hitachi Nuclear Energy Methodology for Development of Reactor Pressure Vessel Pressure Temperature Curves* (Reference 8), for preparation of the P/T curves. The following changes are required to support the relocation of the P/T curves to the PTLR:

- LCO 3.4.11 currently states: “RCS pressure, RCS temperature, RCS heatup and cooldown rates, and the recirculation loop temperature requirements shall be maintained within limits.” To clarify the relocation of the limits to the PTLR, the LCO will be modified to state that the requirements shall be maintained within “...the limits specified in the PTLR.”
- Actions A.1 and C.1 require restoration of the parameters to within limits. To clarify the relocation of the limits to the PTLR, the Actions will be modified to state “...within the limits specified in the PTLR.”

- SR 3.4.11.1 a – "within the limits of the applicable Figure 3.4.11-1" will be replaced with "within the limits specified in the PTLR."
- SR 3.4.11.1 b – "≤ 100°F in any 1 hour period," will be replaced with "within the limits specified in the PTLR."
- SR 3.4.11.2 - "… in the applicable Figure 3.4.11-1" will be replaced with "… in the PTLR."
- SR 3.4.11.3 – "≤ 100°F" will be replaced with "within the limits specified in the PTLR."
- SR 3.4.11.4 – "≤ 50°F" will be replaced with "within the limits specified in the PTLR."
- SRs 3.4.11.5, 3.4.11.6, and 3.4.11.7 – "≥ 70°F" will be replaced with "within the limits specified in the PTLR."
- SR 3.4.11.8 - "≤ 100°F" will be replaced with "within the limits specified in the PTLR."
- SR 3.4.11.9 - "≤ 50°F" will be replaced with "within the limits specified in the PTLR."
- Figure 3.4.11, "Minimum Reactor Vessel Metal Temperature vs. Reactor Vessel Pressure," will be deleted. A note will be added to page 3.4-30 stating "Next page is 3.4-36." This is administrative in nature and allows the current TS page numbering to remain the same.

The creation of a new definition for PTLR (see Section 4.1.4 of this Attachment) and new TS 5.6.6 (see Section 4.1.17 of this Attachment) that adds the administrative reporting requirement TS for the PTLR are also required to support the proposed change.

4.1.16 <u>Main Turbine Bypass System (New TS 3.7.7)</u>

EPU analyses of events that cause a slow pressurization have been performed crediting the main turbine bypass system. On this basis, Entergy proposes to add new TS requirements for this system. The proposed change adds a requirement for two main turbine bypass valves to be operable (see PUSAR Section 2.5.4.3). With two or more valves inoperable, adjustments to the LHGR limits (LCO 3.2.1) and the MCPR limits (LCO 3.2.2) may be applied to allow continued operation. Only two of the three main turbine bypass valves are credited for slow non-limiting anticipated operational occurrences (AOOs) (i.e., those events that cause slow pressurization) such as: the Rod Withdrawal Error (RWE) at power event (refer to GGNS UFSAR Section 15.4.2) and the Loss of Feedwater (LOFW) heating event (refer to GGNS UFSAR Section 15.1.1). Crediting the turbine bypass valves prevents pressurization during these events. Only the RWE and LOFWH events initiating from near RTP will open the bypass valves, therefore the applicable power level is proposed to be 70% RTP.

Two main turbine bypass valves will limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause slow pressurization, such that the Safety Limit MCPR is not exceeded.

Main turbine bypass valves are considered operable when they are capable of opening in response to increasing main steam line pressure. This response is within the assumption of the applicable analysis. The LHGR and MCPR limits for two inoperable main turbine bypass valves will be specified in the COLR.

Limiting events at GGNS have been evaluated with no credit for bypass operation.

The main turbine bypass system is included in the BWR/6 Standard Technical Specifications (Reference 5). The proposed TS supports the analysis for the RWE and LOFW events in which two main turbine bypass valves were credited. Because the events do not credit the response time of the main turbine bypass system, the NUREG SR and definition for Turbine Bypass System Response Time are not included in the GGNS TSs.

The TS is added as required by Criterion 3 of 10 CFR 50.36(c)(2)(ii).

4.1.17 <u>Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR) (New TS 5.6.6)</u>

Evaluations performed in support of EPU identified that the P/T limits should be changed (refer to PUSAR Section 2.1.2). Entergy proposes to implement the new limits in the PTLR. Section 4.1.4 of this Attachment includes a discussion of the new definition and Section 4.1.15 provides a discussion of the new limits and their impact on current TS 3.4.11.

The proposed change includes the administrative requirements for the PTLR and will be incorporated as TS 5.6.6. The proposed PTLR adopts the methodology described in NRC-approved NEDC-33178P-A (Reference 8) for preparation of the pressure-temperature curves. The GGNS PTLR was developed based on the methodology and template provided in NEDC-33178P-A, Revision 1, and is included in Attachment 7 for review.

NRC GL 96-03 (Reference 7) allows plants to relocate their P/T curves and numerical values of other P/T limits (such as heatup/cooldown rate) from the plant TSs to a PTLR, which is a licensee controlled document. The requirements for relocating the P/T curves are satisfied by the use of an NRC-approved analysis methodology and incorporation of a reference to this methodology in the proposed administrative TS.

The GL includes seven technical criteria to which the contents of the proposed methodology should conform for a PTLR to be acceptable to the NRC staff. These seven criteria are addressed in NEDC-33178P-A, Revision 1 (Reference 8) and in the NRC's Safety Evaluation Report (SER) of the licensing topical report (LTR). The SER includes the following Limitations and Conditions:

> The licensee must identify the report used to calculate the neutron fluence and document that the plant-specific neutron fluence calculation will be performed using an approved neutron fluence calculation methodology.

The plant-specific neutron fluence calculation method is referenced in the PTLR (Attachment 7).

4.2 Setpoint Calculation Methodology

Description

The instrument setpoint methodology currently implemented at GGNS is based on Instrument Society of America (ISA) Standard 67.04 Part II, 1994, *Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation* (Reference 10), and the GEH Instrument Setpoint Methodology (ISM) specified in NEDC-31336P-A, *General Electric Instrument Setpoint Methodology* (Reference 11).

Setpoint calculations provide a conservative analysis of setpoints, taking into account the applicable instrument measurement errors.

The Nominal Trip Setpoint (NTSP) is more conservative than the Allowable Value (AV). Because it is impossible to set an instrument channel to an exact value, a calibration tolerance is established around the NTSP. The NTSP is, therefore, considered a nominal value and the instrument adjustment is considered successful if the "as-left" instrument setting is within the calibration tolerance established around the NTSP.

Entergy calculates the setpoints from the Analytical Limit (AL), establishing margins between the AL, the AV, and the NTSP based on calculated instrument errors. Random errors are combined using the square-root-of-the-sum-of-the-squares method, and non-conservative bias errors are added algebraically. This approach provides sufficient margin between the AL and AV to ensure at least 95% probability that the AL is not exceeded if the setpoint drifts toward the AV.

Entergy's Typical Calibration Process

At the start of each calibration, the instrument is declared inoperable (in the case of TS-controlled instruments) and removed from service. The Operations Shift Supervisor or Manager reviews the results of the surveillance and determines whether the results are acceptable based on TS operability requirements prior to returning the instrument to service.

If the as-found setpoint value exceeds its designated tolerance, the condition is documented for trending purposes and appropriate corrective actions are taken before the instrument is returned to service. Once actions have been taken to correct the condition, the instrument setpoint is reset to as close to the NTSP value as practicable and the instrument is returned to service. For cases in which the as-found setpoint value is within its designated tolerance, it is common practice to reset the setpoint value as close to the NTSP value as practicable within the specified as-left tolerance.

This process is applied to both safety-related and non-safety-related setpoints.

At GGNS, trip setpoints are typically verified via channel calibration procedures only.

NRC and Industry Guidance and Application

Over the past several years, the NRC and the nuclear industry have participated in various forums to address the setpoint methodology issue. On September 7, 2005, the NRC transmitted a letter to the NEI Setpoint Methods Task Force that described setpoint-related TS that are acceptable for instrument settings associated with Safety Limit-related setpoints. On August 24, 2006, the NRC issued Regulatory Issue Summary (RIS) 2006-17 (Reference 12) to provide guidance and information pertaining to the requirements of 10 CFR 50.36 with respect to limiting safety system settings (LSSSs) assessed during periodic instrument testing and calibration.

The NRC and industry have been working together on a Technical Specifications Task Force (TSTF) proposal, TSTF-493, *Clarify Application of Setpoint Methodology for LSSS Functions* (Reference 13), to address the setpoint methodology issue. In a letter to the NRC dated February 23, 2009, the TSTF documented a proposed course of action to be taken by the industry to address the NRC's questions and concerns with TSTF-493. The NRC responded in a letter dated March 9, 2009 stating the TSTF letter "meets the agreed course of action …for resolving the TSTF-493 setpoint issue." The NRC's comments have been incorporated into TSTF-493, Rev. 4, which was submitted to the staff on July 31, 2009. The NRC has subsequently approved TSTF-493, Rev. 4.

Safety Limit-Related Limiting Safety System Settings (LSSS) Determination

Attachment A of TSTF-493, Rev. 4 (Reference 13) includes a list of the LSSS functions for BWR/6 plants. The following functions, which are included in Attachment A of TSTF-493, Rev. 4, will be modified to support EPU.

- ARPM Fixed Neutron Flux – High (TS Table 3.3.1.1-1, Function 2.b)
- APRM Flow Biased Simulated Thermal Power – High (TS Table 3.3.1.1-1, Function 2.f.)

In each case, the appropriate notes, as specified in TSTF-493, Rev. 4 Option A were added to the TS as part of the PRNMS LAR (Reference 20). No additional changes are required to address the setpoint methodology issue.

Attachment A of TSTF-493, Rev. 4 also includes Main Steam Line Flow – High (TS Table 3.3.6.1-1, Function 1.c) for which a change is proposed. Consistent with the TSTF-493, the basis for SR 3.3.6.1.3 is being modified to address the plant specific program associated with this function. See Attachment 3 for the proposed TS Bases Markup.

4.3 Methodology Changes

4.3.1 Annulus Pressurization Loads

Mass and Energy Release Methodology Change

The current design basis mass and energy release rates used in the annulus pressurization analysis are generated using the NEDO-24548, *Annulus Pressurization*

Load Adequacy Evaluation (Reference 14), instantaneous break hand calculation methodology.

In light of issues identified in GEH Safety Information Communication SC 09-01, *Annulus Pressurization Loads Evaluation* (Reference 15), dated June 8, 2009, the NEDO-24548 (Reference 14) methodology was considered to be potentially non-conservative as the method could potentially result in artificial shifts of the pressure response frequency content. A more realistic TRACG based mass and energy release analysis methodology for the annulus pressurization loads evaluation was identified to address the SC.

The TRACG break flow model and qualification basis is described in NEDE-32176P, *TRACG Model Description*, (Reference 16) and NEDE-32177P, *TRACG Qualification* (Reference 17). The application of TRACG04 for the calculation of break flow mass/energy release rates has been approved for ESBWR LOCA application in NEDE-33083P-A, *TRACG Application for ESBWR* (Reference 18).

Annulus Pressurization Analysis Methodology Change

The current design basis annulus pressurization analysis is based on the Bechtel subcompartment analysis code, COPDA. In light of issues identified in GEH Safety Information Communication SC 09-01 (Reference 15), the COPDA based analysis of record was judged to be potentially non-conservative due to the coarse nodalization of the annulus, combined with a methodology that is primarily designed to maximize the break node pressure response.

In order to address the issues identified in GEH SC 09-01, a more realistic TRACG based methodology was used for the EPU annulus pressurization loads evaluation. The Grand Gulf EPU TRACG AP model provides a better prediction of the acoustics through the use of a more accurate thermal-hydraulic model combined with an order of magnitude finer mesh used in the nodalization of the annulus.

The application of TRACG04 for the calculation of annulus pressurization loads is described for ESBWR AP application in NEDE-33440P, Revision 2, *TRACG ESBWR Safety Analysis – Additional Information* (Reference 19) dated March 2010. The application of TRACG04 for the GGNS EPU has been applied in a manner consistent with NEDE-33440P.

The annulus pressurization loads defined in the current licensing basis were re-evaluated using TRACG04. PUSAR Section 2.6.2, Subcompartment Analyses, includes a description of the method and the results.

4.3.2 Containment Analysis

The original GGNS long-term containment analysis used the GEH computer code HXSIZ, which modeled thermal equilibrium between the suppression pool and the containment atmosphere. For the power uprate analysis, the SHEX code was used. The SHEX code mechanistically models heat and mass transfer between the suppression pool and the containment airspace.

The proposed use of this methodology, while new to GGNS, is considered acceptable by the NRC based on precedence. As stated in the PUSAR, the SHEX computer code has been used by GEH on all BWR power uprates and accepted by the NRC. The NRC Safety Evaluation Report for the CLTR also states the acceptance of the method.

Refer to PUSAR Section 2.6.1.

4.3.3 Steam Dryer Evaluation

Also in support of the power uprate, an evaluation of the new steam dryer was required. The evaluation was performed using a plant specific plant based load evaluation (PBLE), which is a new methodology for GGNS.

Attachments 11A and 11B include a description of the method and the results.

5.0 REGULATORY ANALYSIS

5.1 Applicable Regulatory Requirements/Criteria

Entergy has determined that the proposed changes do not require any exemptions or relief from regulatory requirements, other than the TS, and do not affect conformance with any General Design Criterion (GDC) differently than described in the Updated Final Safety Analysis Report (UFSAR).

NEDC-33477, *Safety Analysis Report for Grand Gulf Nuclear Station Constant Pressure Power Uprate* (PUSAR), is provided as Attachment 5A (non-proprietary) and Attachment 5B (proprietary). Each PUSAR section contains a regulatory evaluation that describes the relevant regulatory requirements and criteria. A technical evaluation is also included that explains the EPU changes and how the applicable regulatory requirements are met.

The PUSAR follows the format and guidance outlined in RS-001, Revision 0, Office of Nuclear Reactor Regulation, *Review Standard for Extended Power Uprates*, to the extent that the review standard is consistent with the GGNS design basis. For differences between plant-specific design bases and RS-001 regulatory evaluation sections, the corresponding PUSAR regulatory evaluation section was revised to reflect the GGNS design basis.

The proposed EPU is based on the approaches described in the following documents:

- NEDC-33004P-A (commonly called CLTR), *Licensing Topical Report Constant Pressure Power Uprate*, Revision 4
- NEDC-32424P-A (commonly called ELTR1), *Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate* and
- NEDC-32523P-A (commonly called ELTR2), *Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate*

5.2 No Significant Hazards Consideration

The proposed changes to the Grand Gulf Nuclear Station (GGNS) Operating License (OL) and Technical Specifications (TS) support the implementation of an Extended Power Uprate (EPU) to 4408 MWt. The change also includes the use of new methodologies. Entergy Operations, Inc. has evaluated whether or not a significant hazards consideration is involved with the proposed changes by focusing on the three standards set forth in 10 CFR 50.92, *Issuance of amendment*, as discussed below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No, the increase in power level does not significantly increase the probably or consequences of an accident previously evaluated.

   The proposed change will increase the maximum authorized core power level for GGNS from the current licensed thermal power (CLTP) of 3898 megawatts thermal (MWt) to 4408 MWt. Evaluations and analyses of the nuclear steam supply system (NSSS) and balance of plant (BOP) structures, systems, and components (SSCs) that could be affected by the power uprate were performed in accordance the approaches described in:

   - NEDC-33004P-A (commonly called CLTR), *Licensing Topical Report Constant Pressure Power Uprate*, Revision 4
   - NEDC-32424P-A (commonly called ELTR1), *Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate* and
   - NEDC-32523P-A (commonly called ELTR2), *Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate*

   The evaluations concluded that all plant components, as modified, will continue to be capable of performing their design function at the proposed uprated core power level.

   The GGNS licensing and design bases, including GGNS accident analyses, were also evaluated for the effect of the proposed power increase. The evaluation concluded that the applicable analysis acceptance criteria continue to be met. Power level is not an initiator of any transient or accident; it is used as an input assumption to equipment design and accident analyses.

   The proposed change does not affect the release paths or the frequency of release for any accidents previously evaluated in the UFSAR. Structures, systems, and components required to mitigate transients remain capable of performing their design functions considering radiological consequences associated with the effect of the proposed EPU. The source terms used to evaluate the radiological consequences were reviewed and were determined to bound operation at EPU power levels. The results of EPU accident evaluations do not exceed NRC-approved acceptance limits.

The spectrum of postulated accidents and transients were reviewed and were shown to meet the regulatory criteria to which GGNS is currently licensed. In the area of fuel and core design, the Safety Limit Minimum Critical Power Ratio (SLMCPR) and other Specified Acceptable Fuel Design Limits (SAFDLs) are still met. Continued compliance with the SLMPCR and other SAFDLs is confirmed on a cycle specific basis consistent with the criteria accepted by the NRC.

Challenges to the reactor coolant pressure boundary were evaluated at EPU conditions (pressure, temperature, flow, and radiation) and found to meet the acceptance criteria for allowable stresses. Adequate overpressure margin is maintained.

Challenges to the containment were also evaluated. Containment and its associated cooling system continue to meet applicable regulatory requirements. The increase in the calculated post Loss of Coolant Accident (LOCA) suppression pool temperature above the current design limit was evaluated and determined to be acceptable.

Radiological releases were evaluated and found to be within the regulatory limits of 10CFR 50.67, *Accident Source Terms*.

Change in Methodologies

The use of more accurate modeling of the annulus pressurization loads is not relevant to accident initiation, but rather, pertains to the method used to accurately evaluate annulus pressurization during postulated accidents. The use of a new method does not, in any way, alter any fission product barrier or SSC and provides a better representation of dynamic behavior.

The GGNS containment analysis was performed using the SHEX computer code, which is not relevant to accident initiation.

The GGNS steam dryer evaluation was performed using a plant based load evaluation method. The use of this evaluation is not relevant to accident initiation. The steam dryer is a non-safety related component.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

   Response: No, the increase in power does not create the possibility of a new or different kind of accident from any previously evaluated.

   The proposed change increases the maximum authorized core power level for GGNS from the CLTP of 3898 MWt to 4408 MWt. An evaluation of the equipment that could be affected by the power uprate has been performed. No new operating modes, safety-related equipment lineups, accident scenarios, or equipment failure modes were identified. The full spectrum of accident considerations was evaluated and no new or different kinds of accidents were identified. For GGNS, the standard evaluation methods outlined in CLTR, ELTR1, and ELTR2 were applied to the capability of existing or modified safety-related plant equipment. No new accidents or event precursors were identified.

All SSCs previously required for the mitigation of a transient remain capable of fulfilling their intended design functions. The proposed increase in power does not adversely affect safety-related systems or components and does not challenge the performance or integrity of any safety-related system. The change does not adversely affect any current system interfaces or create any new interfaces that could result in an accident or malfunction of a different kind than was previously evaluated. Operating at the proposed EPU power level does not create any new accident initiators or precursors.

Change in Methodologies

The use of more accurate modeling of the annulus pressurization loads is not relevant to accident initiation, but rather, pertains to the method used to accurately evaluate annulus pressurization during postulated accidents. The use of this methodology does not involve any physical changes to plant structures or systems, and does not create a new initiating event for the spectrum of events currently postulated. Further, the methodologies do not result in the need to postulate any new accident scenarios.

The GGNS containment analysis was performed using the SHEX computer code, which is not an accident initiator and therefore does not result in the creation of any new accidents.

The use of the plant based load evaluation method to perform the GGNS steam dryer analysis does not result in the creation of any new accidents since the steam dryer is not safety-related and is not considered an accident initiator.

Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any previously evaluated.

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

Response: No, the proposed increase in power does not involve a significant reduction in a margin of safety.

Based on the analyses of the proposed power increase, the relevant design and safety acceptance criteria will be met without a significant reduction in margins of safety. The analyses supporting EPU have demonstrated that the GGNS SSCs are capable of safely performing at EPU conditions. The analyses identified and defined the major input parameters to the NSSS, analyzed NSSS design transients, and evaluated the capabilities of the NSSS fluid systems, NSSS/BOP interfaces, NSSS control systems, and NSSS and BOP components, as appropriate. Radiological consequences of design basis events remain within regulatory limits and are not increased significantly. The analyses confirmed that

NSSS and BOP SSCs are capable, some with modifications, of achieving EPU conditions without significant reduction in margins of safety.

Analyses have shown that the integrity of primary fission product barriers will not be significantly affected as a result of the power increase. Calculated loads on SSCs important to safety have been shown to remain within design allowables under EPU conditions for all design basis event categories. Plant response to transients and accidents do not result in exceeding acceptance criteria.

As appropriate, the evaluations that demonstrate acceptability of EPU have been performed using methods that have either been reviewed and approved by the NRC staff, or that are in compliance with regulatory review guidance and standards established for maintaining adequate margins of safety. These evaluations demonstrate that there are no significant reductions in the margins of safety.

Maximum power level is one of the inherent inputs that determine the safe operating range defined by the accident analyses. The Technical Specifications ensure that GGNS is operated within the bounds of the inputs and assumptions used in the accident analyses. The acceptance criteria for the accident analyses are conservative with respect to the operating conditions defined by the Technical Specifications. The engineering reviews performed for the constant pressure extended power uprate confirm that the accident analyses criteria are met at the revised maximum allowable thermal power level of 4408 MWt. Therefore, the adequacy of the revised Facility Operating License and Technical Specifications to maintain the plant in a safe operating range is also confirmed, and the increase in maximum allowable power level does not involve a significant decrease in a margin of safety.

Change in Methodologies

The use of more accurate modeling of the annulus pressurization loads is not relevant to accident initiation, but rather, pertains to the method used to accurately evaluate annulus pressurization during postulated accidents. The use of a more accurate methodology to generate mass and energy release rates reduces the potential for methodology induced response profile frequency shifts that could result in a non-conservative load assessment. The use of more accurate methods, to minimize the impact of methodology induced response profile frequency shifts, does not result in a reduction in the margin of safety.

In light of issues identified in GEH Safety Information Concern SC 09-01, *Annulus Pressurization Loads Evaluation*, dated June 8, 2009, a realistic annulus pressurization methodology is required to ensure that the frequency content of the annulus pressurization transient is captured and correctly accounted for in the downstream structural, component and piping load analyses. The use of more accurate modeling of the annulus pressurization loads does not adversely impact containment SSCs or the subcompartments.

The GGNS containment analysis was performed using the SHEX computer code. The results of the containment analysis demonstrate that the containment remains within all of its design limits following the most limiting design basis accident.

The steam dryer evaluation was performed in accordance with Regulatory Guide 1.20, *Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing*. The non-safety related replacement steam dryer conservatively exceeds the vibration and stress requirements.

Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

Based on the above, Entergy concludes that the proposed amendment presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

5.3 Environmental Considerations

In support of the proposed changes to the Facility Operating License and Technical Specifications for implementation of an EPU at GGNS, Attachment 4, "Extended Power Uprate Environmental Assessment," provides the required environmental review. The review has been performed in accordance with the regulatory guidance as set forth in 10 CFR 51.20, *Criteria for and Identification of Licensing and Regulatory Actions Requiring Environmental Report*. The assessment concludes that the environmental impacts of operation at 4408 MWt are bounded by the previous assumptions and conclusions described in the 1981 *Final Environmental Statement for the Operation of the Grand Gulf Nuclear Station Units 1 and 2 (NUREG-0777)* and other State and Federal regulatory requirements.

6.0 REFERENCES

1. RS-001, Revision 0, Office of Nuclear Reactor Regulation, *Review Standard for Extended Power Uprates*, December 2003
2. NEDC-33004P-A (commonly called CLTR), Revision 4, *Constant Pressure Power Uprate*, July 2003
3. NEDC-32424P-A (commonly called ELTR1), *Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate*, February 1999
4. NEDC-32523P-A (commonly called ELTR2), *Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate*, February 2000
5. NUREG-1434, Revision 3.1, *Standard Technical Specifications, General Electric Plants, BWR/6*
6. TSTF-419-A, *Revise PTLR Definition and References in ISTS 5.6.6, RCS PTLR*
7. Generic Letter 96-03, *Relocation of the Pressure Temperature Limit Curves and Low Temperature Overpressure Protection System Limits*, January 31, 1996

8. NEDC-33178P-A, Revision 1, *GE Hitachi Nuclear Energy Methodology for Development of Reactor Pressure Vessel Pressure Temperature Curves*, June 2009

9. NEDE-24011P-A (commonly called GESTAR II), *General Electric Standard Application for Reactor Fuel*, latest approved version

10. Instrument Society of America (ISA) Standard 67.04 Part II, 1994, *Methodologies for the Determination of Setpoints for Nuclear Safety-Related Instrumentation*

11. NEDC-31336P-A, *General Electric Instrument Setpoint Methodology*, September 1996

12. NRC RIS 2006-17, *NRC Staff Position on the Requirements of 10 CFR 50.36, "Technical Specifications," Regarding Limiting Safety System Settings During Periodic Testing and Calibration of Instrument Channels*

13. TSTF-493, Revision 4, *Clarify Application of Setpoint Methodology for LSSS Functions*, April 20, 2010

14. NEDO-24548, *Annulus Pressurization Load Adequacy Evaluation*, January 1979

15. GEH Safety Information Communication, SC 09-01, *Annulus Pressurization Loads Evaluation*, dated June 8, 2009

16. NEDE-32176P, Revision 4, *TRACG Model Description*

17. NEDE-32177P, Revision 3, *TRACG Qualification*

18. NEDE-33083P-A, *TRACG Application for ESBWR*, October 2005

19. NEDE-33440P, Revision 2, *TRACG ESBWR Safety Analysis – Additional Information*, March 2010

20. Entergy Operations, Inc. letter to the NRC, *License Amendment Request – Power Range Neutron Monitoring System Upgrade*, dated November 3, 2009 (ADAMS Accession No. ML093140463).

Attachment 2

GNRO-2010/00056

Proposed Operating License and Technical Specification Changes (Mark-up)

(b) SERI is required to notify the NRC in writing prior to any change in (i) the terms or conditions of any new or existing sale or lease agreements executed as part of the above authorized financial transactions, (ii) the GGNS Unit 1 operating agreement, (iii) the existing property insurance coverage for GGNS Unit 1 that would materially alter the representations and conditions set forth in the Staff's Safety Evaluation Report dated December 19, 1988 attached to Amendment No. 54. In addition, SERI is required to notify the NRC of any action by a lessor or other successor in interest to SERI that may have an effect on the operation of the facility.

C. The license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

4408

Entergy Operations, Inc. is authorized to operate the facility at reactor core power levels not in excess of ~~3898~~ megawatts thermal (100 percent power) in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, as revised through Amendment No. 184 are hereby incorporated into this license. Entergy Operations, Inc. shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

Proposed in the Power Range Neutron Monitoring System (PRNMS) License Amendment Request (LAR).

During Cycle 19, GGNS will conduct monitoring of the Oscillation Power Range Monitor (OPRM). During this time, the OPRM Upscale function (Function 2.f of Technical Specification Table 3.3.1.1-1) will be disabled and operated in an `indicate only' mode and technical specification requirements will not apply to this function. During such time, Backup Stability Protection measures will be implemented via GGNS procedures to provide an alternate method to detect and suppress reactor core thermal hydraulic instability oscillations. Once monitoring has been successfully completed, the OPRM Upscale function will be enabled and technical specification requirements will be applied to the function; no further operating with this function in an “indicate only” mode will be conducted.

(b) The first performance of the periodic assessment of CRE habitability, Specification 5.5.13.c.(ii), shall be within 3 years, plus the 9-month allowance of SR 3.0.2, as measured from March 2005, the date of the most recent successful tracer gas test, as stated in the June 30, 2005 letter response to Generic Letter 2003-01, or within the next 9 months if the time period since the most recent successful tracer gas test is greater than 3 years.

(c) The first performance of the periodic assessment of the CRE boundary, Specification 5.5.13.d, shall be within the next 18 months, plus the 136 days allowed by SR 3.0.2, as measured from the date of issuance of this amendment.

D. The facility required exemptions from certain requirements of Appendices A and J to 10 CFR Part 50 and from certain requirements of 10 CFR Part 100. These include: (a) exemption from General Design Criterion 17 of Appendix A until startup following the first refueling outage, for (1) the emergency override of the test mode for the Division 3 diesel engine, (2) the second level undervoltage protection for the Division 3 diesel engine, and (3) the generator ground over current trip function for the Division 1 and 2 diesel generators (Section 8.3.1 of SSER #7) and (b) exemption from the requirements of Paragraph III.D.2(b)(ii) of Appendix J for the containment airlock testing following normal door opening when containment integrity is not required (Section 6.2.6 of SSER #7). These exemptions are authorized by law and will not endanger life or property or the common defense and security and are otherwise in the public interest. In addition, by exemption dated December 20, 1986, the Commission exempted licensees from 10 CFR 100.11(a)(1), insofar as it incorporates the definition of exclusion area in 10 CFR 100.3(a), until April 30, 1987 regarding demonstration of authority to control all activities within the exclusion area (safety evaluation accompanying Amendment No. 27 to License (NPF-29). This exemption is authorized by law, and will not present an undue risk to the public health and safety, and is consistent with the common defense and security. In addition, special circumstances have been found justifying the exemption. Therefore, these exemptions are hereby granted pursuant to 10 CFR 50.12. with the granting of these exemptions, the facility will operate, to the extent authorized herein, in conformity with the application, as amended, the provisions of the Act and the rules and regulations of the Commission.

E. The licensee shall fully implement and maintain in effect all provision of the Commission-approved physical security, training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: “Physical Security, Safeguards Contingency and Training and Qualification Plan,” and were submitted to the NRC on May 18, 2006.

(44) Leak rate tests associated with Surveillance Requirements (SR) 3.6.1.1.1, 3.6.1.3.5, and 3.6.1.3.9, as required by TS 5.5.12 and in accordance with 10 CFR 50, Appendix J, Option B, and SRs 3.6.5.1.1and 3.6.5.1.2 are not required to be performed until their next scheduled performance dates. The tests will be performed at the EPU calculated long-term peak containment pressure or within EPU drywell bypass leakage limits, as appropriate.

(45) EOI will not operate GGNS at a thermal power level above 3,898 MWt until the Power Range Neutron Monitoring System license amendment request is approved by the NRC.

1.1 Definitions

LOGIC SYSTEM FUNCTIONAL TEST (continued)	be performed by means of any series of sequential, overlapping, or total system steps so that the entire logic system is tested.
MINIMUM CRITICAL POWER RATIO (MCPR)	The MCPR shall be the smallest critical power ratio (CPR) that exists in the core for each class of fuel. The CPR is that power in the assembly that is calculated by application of the appropriate correlation(s) to cause some point in the assembly to experience boiling transition, divided by the actual assembly operating power.
MODE	A MODE shall correspond to any one inclusive combination of mode switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.
OPERABLE—OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).
PRESSURE TEMPERATURE LIMITS REPORT (PTLR)	The PTLR is the unit-specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of ~~3898~~ 4408 MWt.
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.

(continued)

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

2.1.1.1 With the reactor steam dome pressure < ~~785~~ 685 psig or core flow < 10% rated core flow:

THERMAL POWER shall be ≤ ~~25%~~ 21.8% RTP.

2.1.1.2 With the reactor steam dome pressure ≥ ~~785~~ 685 psig and core flow ≥ 10% rated core flow:

MCPR shall be ≥ 1.09 for two recirculation loop operation or ≥ 1.12 for single recirculation loop operation.

2.1.1.3 Reactor vessel water level shall be greater than the top of active irradiated fuel.

2.1.2 Reactor Coolant System Pressure SL

Reactor steam dome pressure shall be ≤ 1325 psig.

2.2 SL Violations

With any SL violation, the following actions shall be completed within 2 hours:

2.2.1 Restore compliance with all SLs; and

2.2.2 Insert all insertable control rods.

(continued)

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ~~Concentration of boron in solution in Limited Operation region.~~ (C)(E) < 420	A.1 ~~Restore concentration of boron in solution to Normal Operation region.~~ Restore (C)(E) ≥ 420 AND ~~A.2 Perform SR 3.1.7.2.~~	~~72 hours~~ 8 hours ~~Once per 4 hours~~
D. ~~B.~~ One SLC subsystem inoperable.	~~B.1~~ D.1 Restore SLC subsystem to OPERABLE status.	7 days
E. ~~C.~~ Two SLC subsystems inoperable. for reasons other than Conditions A, B or C.	E.1 ~~C.1~~ Restore one SLC subsystem to OPERABLE status.	8 hours
F. ~~D.~~ Required Action and associated Completion Time not met.	~~D.1~~ F.1 Be in MODE 3.	12 hours
B. Sodium pentaborate solution volume < 4,200 gallons.	B.1 Restore Volume to ≥ 4,200 gallons.	8 hours
C. Temperature < 45°F or > 150°F.	C.1 Restore temperature ≥45°F or ≤150°F.	8 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.1.7.1	Verify available volume of sodium pentaborate solution is ~~within the limits of Figure 3.1.7-1.~~ ≥ 4,200 gallons.	24 hours
SR 3.1.7.2	Verify temperature of sodium pentaborate solution is ~~within the limits of Figure 3.1.7-2.~~ ≥45°F or ≤150°F.	24 hours
SR 3.1.7.3	~~Verify temperature of pump suction piping is ≥ 75°F and ≤ 130°F.~~	~~24 hours~~ 31 days
SR 3.1.7.4	Verify continuity of explosive charge.	31 days
SR 3.1.7.5	~~Verify the concentration of boron in solution is within the limits of Figures 3.1.7-1 and 3.1.7-2.~~ Verify the percent weight of sodium pentaborate in solution is ≤9.5%.	31 days AND Once within 24 hours after water or boron is added to solution AND Once within 24 hours after solution temperature is restored to ≥ ~~75°F~~ 45°F

(continued)

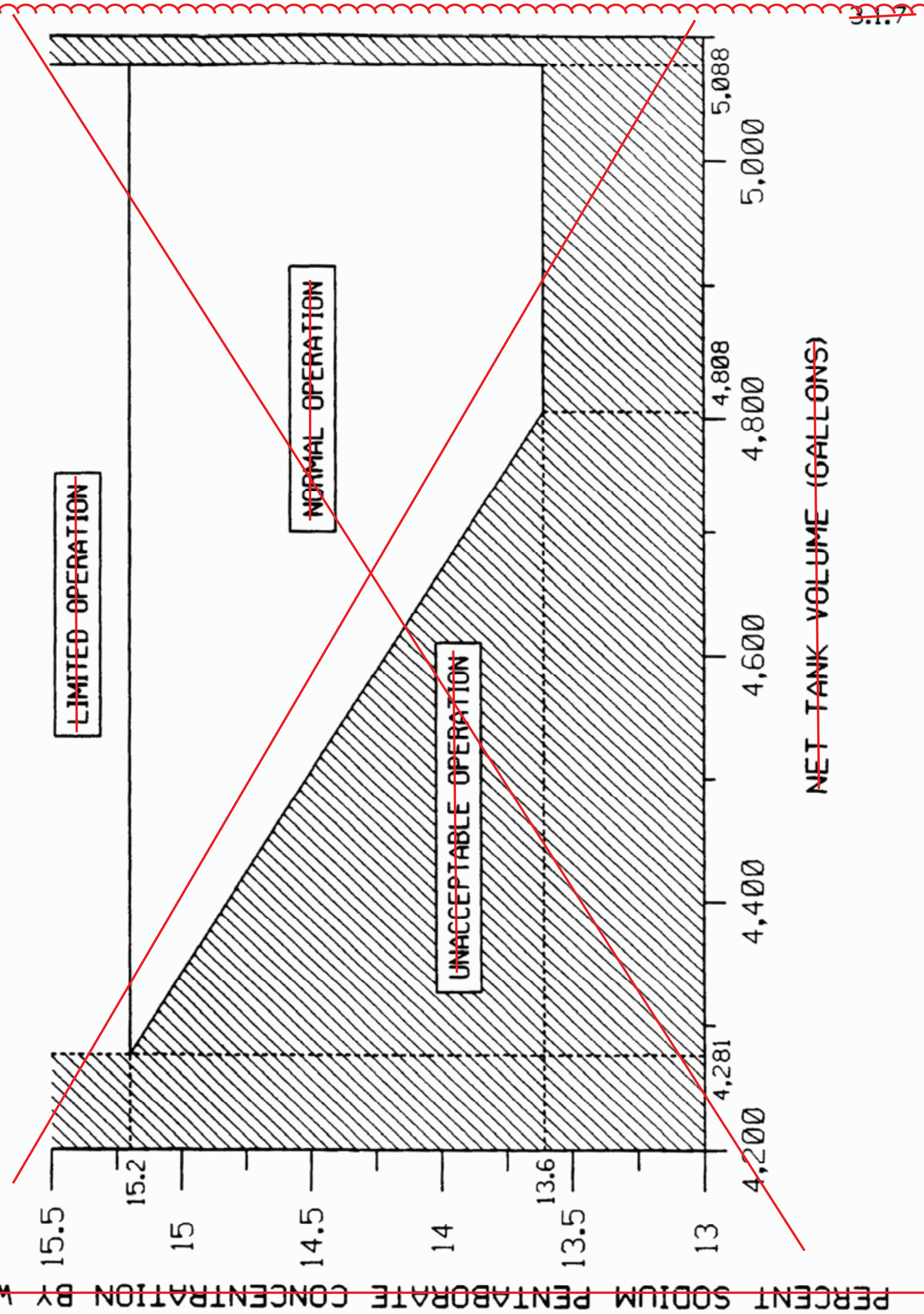
-------------------------------NOTE----------------------------------
Sodium Pentaborate Concentration (C), in weight percent is determined by the performance of SR 3.1.7.5. Boron-10 enrichment (E), in atom percent is determined by the performance of SR 3.1.7.9.

Verify SLC System satisfies the following equation:
(C)(E) ≥ 420

SURVEILLANCE REQUIREMENTS (continued)

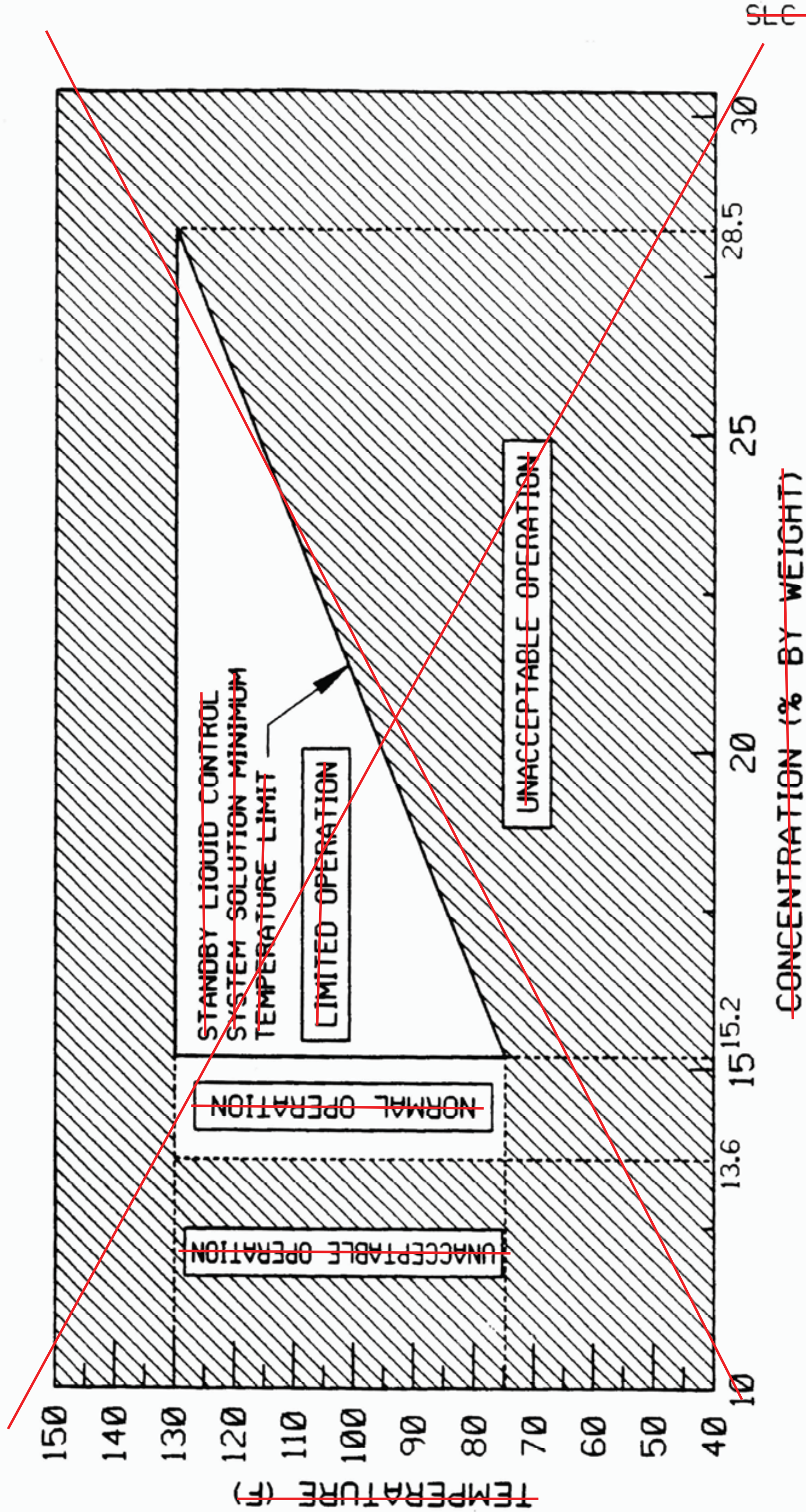
SURVEILLANCE		FREQUENCY
SR 3.1.7.6	Verify each SLC subsystem manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, is in the correct position, or can be aligned to the correct position.	31 days
SR 3.1.7.7	Verify each pump develops a flow rate ≥ 41.2 gpm at a discharge pressure ≥ ~~1300~~ psig. 1340	In accordance with the Inservice Testing Program
SR 3.1.7.8	Verify flow through one SLC subsystem from pump into reactor pressure vessel.	18 months on a STAGGERED TEST BASIS
SR 3.1.7.9	~~Verify all heat traced piping between storage tank and pump suction is unblocked.~~ Determine Boron-10 enrichment.	~~18 months~~ ~~AND~~ ~~Once within 24 hours after pump suction piping temperature is restored to ≥ 75°F~~ Once within 24 hours after boron is added to the solution.

Next page is 3.1-26.



~~FIGURE 3.1.7-1~~

~~SODIUM PENTABORATE SOLUTION CONCENTRATION/AVAILABLE VOLUME REQUIREMENTS~~



~~FIGURE 3.1.7-2~~

~~SODIUM PENTABORATE SOLUTION TEMPERATURE/CONCENTRATION REQUIREMENTS~~

3.2 POWER DISTRIBUTION LIMITS

3.2.1 Average Planar Linear Heat Generation Rate (APLHGR)

LCO 3.2.1 All APLHGRs shall be less than or equal to the limits specified in the COLR.

21.8%

APPLICABILITY: THERMAL POWER ≥ ~~25%~~ RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any APLHGR not within limits	A.1 Restore APLHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < ~~25%~~ RTP. 21.8%	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.1.1 Verify all APLHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ ~~25%~~ RTP 21.8% AND 24 hours thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.2 Minimum Critical Power Ratio (MCPR)

LCO 3.2.2 All MCPRs shall be greater than or equal to the MCPR operating limits specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ ~~25%~~ 21.8% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any MCPR not within limits	A.1 Restore MCPR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < ~~25%~~ 21.8% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify all MCPRs are greater than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ ~~25%~~ 21.8% RTP <u>AND</u> 24 hours thereafter
SR 3.2.2.2	Determine the MCPR limits.	Once within 72 hours after each completion of SR 3.1.4.1 Once within 72 hours after each completion of SR 3.1.4.2 Once within 72 hours after each completion of SR 3.1.4.4

3.2 POWER DISTRIBUTION LIMITS

3.2.3 Linear Heat Generation Rate (LHGR)

LCO 3.2.3 All LHGRs shall be less than or equal to the limits specified in the COLR.

21.8%

APPLICABILITY: THERMAL POWER ≥ ~~25%~~ RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any LHGR not within limits	A.1 Restore LHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < ~~25%~~ RTP. 21.8%	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.2.3.1 Verify all LHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ ~~25%~~ RTP 21.8% <u>AND</u> 24 hours thereafter

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1 Reduce THERMAL POWER to < ~~40%~~ 35.4% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1 Reduce THERMAL POWER to < ~~25%~~ 21.8% RTP.	4 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1 Be in MODE 2.	6 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1 Be in MODE 3.	12 hours
I. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	I.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
J. As required by Required Action D.1 and referenced in Table 3.3.1.1-1. This markup shows the impact of EPU to the proposed Technical Specification changes in the PRNMS LAR.	J.1 Initiate alternate method to detect and suppress thermal hydraulic instability oscillations. <u>AND</u> J.2 --------- NOTE --------- LCO 3.0.4 is not applicable. ------------------------- Restore required channels to OPERABLE.	12 hours 120 days
K. Required Action and associated Completion Time of Condition J not met.	K.1 Reduce THERMAL POWER to < ~~24%~~ 21% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

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

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains RPS trip capability.

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.1.2	-------------------NOTE------------------- Not required to be performed until 12 hours after THERMAL POWER ≥ ~~25%~~ 21.8% RTP. -- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power ≤ 2% RTP while operating at ≥ ~~25%~~ 21.8% RTP.	7 days
SR 3.3.1.1.3	-------------------NOTE------------------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.4	Perform CHANNEL FUNCTIONAL TEST.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.11	Perform CHANNEL FUNCTIONAL TEST.	18 months
SR 3.3.1.1.12	-------------------NOTES------------------- 1. Neutron detectors are excluded. 2. For IRMs, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. --- Perform CHANNEL CALIBRATION.	18 months
SR 3.3.1.1.13	Perform LOGIC SYSTEM FUNCTIONAL TEST.	18 months
SR 3.3.1.1.14	Verify Turbine Stop Valve Closure, Trip Oil Pressure—Low and Turbine Control Valve Fast Closure Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ ~~40%~~ 35.4% RTP.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.22	------------------ NOTE ------------------ For Function 2.e, "n" equals 8 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. Testing APRM and OPRM outputs shall alternate. -- Verify the RPS RESPONSE TIME is within limits.	24 months on a STAGGERED TEST BASIS
SR 3.3.1.1.23	Verify OPRM is not bypassed when APRM Simulated Thermal Power is greater than or equal to ~~29%~~ RTP and recirculation drive flow is less than 60% of rated recirculation drive flow. 26%	24 months

Impact of EPU on changes in proposed PRNMS LAR are reflected.

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux — High	2	3	H	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.12 SR 3.3.1.1.13	≤122/125 divisions of full scale
	5(a)	3	I	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 122/125 divisions of full scale
b. Inop	2	3	H	SR 3.3.1.1.3 SR 3.3.1.1.13	NA
	5(a)	3	I	SR 3.3.1.1.4 SR 3.3.1.1.13	NA
2. Average Power Range Monitors					
a. Neutron Flux - High, Setdown	2	3(c)	H	SR 3.3.1.1.7 SR 3.3.1.1.10(d)(e) SR 3.3.1.1.19 SR 3.3.1.1.20	≤ 20% RTP
b. Fixed Neutron Flux - High	1	3(c)	G	SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.10(d)(e) SR 3.3.1.1.19 SR 3.3.1.1.20	≤ ~~120%~~ 119.3% RTP
c. Inop	1,2	3(c)	H	SR 3.3.1.1.20	NA
d. Flow Biased Simulated Thermal Power - High	1	3(c)	G	SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.10(d)(e) SR 3.3.1.1.17 SR 3.3.1.1.19 SR 3.3.1.1.20	(b)
e. 2-Out-Of-4 Voter	1, 2	2	H	SR 3.3.1.1.19 SR 3.1.1.1.20 SR 3.1.1.1.21 SR 3.1.1.1.22	NA
f. OPRM Upscale	≥~~24%~~ 21% RTP	3(c)	J	SR 3.3.1.1.7 SR 3.3.1.1.10(d)(e) SR 3.3.1.1.19 SR 3.3.1.1.20 SR 3.3.1.1.23	(f)

Impact of EPU on changes proposed in PRNMS LAR are reflected on this page.

(continued)

(a) With any control rod withdrawn from a core cell containing one or more fuel assemblies.
(b) Two-Loop Operation: ~~0.65W + 62.9% RTP~~ 0.58W +59.1% RTP and ≤ 113% RTP
Single-Loop Operation: ~~0.65W + 42.3% RTP~~ 0.58W +37.4% RTP
(c) Each channel provides inputs to both trip systems.
(d) If the as-found channel setpoint is outside its pre-defined as-found tolerance, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.
(e) The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the NTSP are acceptable provided the as-found and as-left tolerances apply to the actual setpoint implemented in the Surveillance procedures to confirm channel performance. The NTSP and the methodologies used to determine the as-found and as-left tolerances are specified in the Technical Requirements Manual.
(f) The Allowable Value for the OPRM Upscale Period-Based Detection algorithm is specified in the COLR.

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. Reactor Vessel Steam Dome Pressure — High	1,2	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 1079.7 psig
4. Reactor Vessel Water Level — Low, Level 3	1,2	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.15	≥ 10.8 inches
5. Reactor Vessel Water Level — High, Level 8	≥ ~~25%~~ 21.8% RTP	2	F	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 54.1 inches
6. Main Steam Isolation Valve — Closure	1	8	G	SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 7% closed
7. Drywell Pressure — High	1,2	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 1.43 psig
8. Scram Discharge Volume Water Level — High					
a. Transmitter/Trip Unit	1,2	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 63% of full scale
	5(a)	2	I	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 63% of full scale
b. Float Switch	1,2	2	H	SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 65 inches
	5(a)	2	I	SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.13	≤ 65 inches

(continued)

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

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
9. Turbine Stop Valve Closure, Trip Oil Pressure — Low	≥ ~~40%~~ 35.4% RTP	4	E	SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≥ 37 psig
10. Turbine Control Valve Fast Closure, Trip Oil Pressure — Low	≥ ~~40%~~ 35.4% RTP	2	E	SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15	≥ 42 psig
11. Reactor Mode Switch — Shutdown Position	1,2	2	H	SR 3.3.1.1.11 SR 3.3.1.1.13	NA
	5(a)	2	I	SR 3.3.1.1.11 SR 3.3.1.1.13	NA
12. Manual Scram	1,2	2	H	SR 3.3.1.1.4 SR 3.3.1.1.13	NA
	5(a)	2	I	SR 3.3.1.1.4 SR 3.3.1.1.13	NA

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

3.3 INSTRUMENTATION

3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

LCO 3.3.4.1

a. Two channels per trip system for each EOC-RPT instrumentation Function listed below shall be OPERABLE:

1. Turbine Stop Valve (TSV) Closure, Trip Oil Pressure—Low; and

2. Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure—Low.

<u>OR</u>

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for inoperable EOC-RPT as specified in the COLR are made applicable.

APPLICABILITY: THERMAL POWER ≥ ~~40%~~ 35.4% RTP with any recirculation pump in fast speed.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Restore channel to OPERABLE status. <u>OR</u>	72 hours (continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	--------NOTE--------- Not applicable if inoperable channel is the result of an inoperable breaker. --------------------- Place channel in trip.	72 hours
B. One or more Functions with EOC-RPT trip capability not maintained. <u>AND</u> MCPR limit for inoperable EOC-RPT not made applicable.	B.1	Restore EOC-RPT trip capability.	2 hours
	<u>OR</u>		
	B.2	Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	2 hours
C. Required Action and associated Completion Time not met.	C.1	Remove the associated recirculation pump fast speed breaker from service.	4 hours
	<u>OR</u>		
	C.2	Reduce THERMAL POWER to < 40% RTP. 35.4%	4 hours

SURVEILLANCE REQUIREMENTS

-------------------------------------NOTE-------------------------------------
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains EOC-RPT trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.1	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.4.1.2	Calibrate the trip units.	92 days
SR 3.3.4.1.3	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. TSV Closure, Trip Oil Pressure—Low: ≥ 37 psig. b. TCV Fast Closure, Trip Oil Pressure - Low: ≥ 42 psig.	18 months
SR 3.3.4.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation.	18 months
SR 3.3.4.1.5	Verify TSV Closure, Trip Oil Pressure—Low and TCV Fast Closure, Trip Oil Pressure—Low Functions are ~~not~~ bypassed when THERMAL POWER is ≥ ~~40%~~ 35.4% RTP.	18 months

(continued)

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level — Low Low Low, Level 1	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7 SR 3.3.6.1.8	≥ -152.5 inches
b. Main Steam Line Pressure — Low	1	2	E	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7 SR 3.3.6.1.8	≥ 837 psig
c. Main Steam Line Flow — High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7 SR 3.3.6.1.8	≤ ~~176.5~~ 255.9 psid
d. Condenser Vacuum — Low	1,2(a), 3(a)	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ 8.7 inches Hg vacuum
e. Main Steam Tunnel Ambient Temperature — High	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.5 SR 3.3.6.1.7	≤ 191°F
f. Manual Initiation	1,2,3	2	G	SR 3.3.6.1.7	NA
2. Primary Containment and Drywell Isolation					
a. Reactor Vessel Water Level — Low Low, Level 2	1,2,3	2(b)	H	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ -43.8 inches

(continued)

(a) With any turbine stop valve not closed.

(b) Also required to initiate the associated drywell isolation function.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	-------------------NOTES------------------- 1. Not required to be performed until 4 hours after associated recirculation loop is in operation. 2. Not required to be performed until 24 hours after > ~~25%~~ 21.8% RTP. --- Verify at least two of the following criteria (a, b, and c) are satisfied for each operating recirculation loop: a. Recirculation loop drive flow versus flow control valve position differs by ≤ 10% from established patterns. b. Recirculation loop drive flow versus total core flow differs by ≤ 10% from established patterns. c. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns, or each jet pump flow differs by ≤ 10% from established patterns.	24 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 Safety/Relief Valves (S/RVs)

nine

LCO 3.4.4 The safety function of ~~seven~~ S/RVs shall be OPERABLE,

AND

The relief function of six additional S/RVs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required S/RVs inoperable.	A.1 Be in MODE 3.	12 hours
	AND	
	A.2 Be in MODE 4.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.4.1 Verify the safety function lift setpoints of the required S/RVs are as follows: Number of S/RVs — Setpoint (psig) 8 — 1165 ± 34.9 6 — 1180 ± 35.4 6 — 1190 ± 35.7	In accordance with the Inservice Testing Program

(continued)

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.11 RCS pressure, RCS temperature, RCS heatup and cooldown rates, and the recirculation loop temperature requirements shall be maintained within ~~limits~~.

the limits specified in the PTLR.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------NOTE--------- Required Action A.2 shall be completed if this Condition is entered. --------------------- Requirements of the LCO not met in MODES 1, 2, and 3.	A.1 Restore parameter(s) to within ~~limits~~. AND A.2 Determine RCS is acceptable for continued operation.	30 minutes 72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. --------NOTE--------- Required Action C.2 shall be completed if this Condition is entered. --------------------- Requirements of the LCO not met in other than MODES 1, 2, and 3.	C.1 Initiate action to restore parameter(s) to within ~~limits.~~ the limits specified in the PTLR. AND C.2 Determine RCS is acceptable for operation.	Immediately Prior to entering MODE 2 or 3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	------------------NOTE------------------- Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. -- Verify: a. RCS pressure and RCS temperature are ~~within the limits of the applicable Figure 3.4.11-1~~ based on the current Effective Full Power Year (EFPY), and b. RCS heatup and cooldown rates are ~~≤ 100°F in any 1 hour period.~~ within the limits specified in the PTLR	30 minutes

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.11.2	-------------------NOTE------------------- Only required to be met during control rod withdrawal for the purpose of achieving criticality. -- Verify RCS pressure and RCS temperature are within the criticality limits specified in the ~~applicable Figure 3.4.11-1 based on the current Effective Full Power Year (EFPY).~~ PTLR	Once within 15 minutes prior to control rod withdrawal for the purpose of achieving criticality
SR 3.4.11.3	-------------------NOTE------------------- Only required to be met in MODES 1, 2, 3, and 4 with reactor steam dome pressure ≥ 25 psig during recirculation pump start. -- Verify the difference between the bottom head coolant temperature and the reactor pressure vessel (RPV) coolant temperature is ~~≤ 100°F.~~ within the limits specified in the PTLR.	Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.11.4	-------------------NOTE------------------- Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump start. -- Verify the difference between the reactor coolant temperature in the recirculation loop to be started and the RPV coolant temperature is ~~≤ 50°F.~~ within the limits specified in the PTLR.	Once within 15 minutes prior to each startup of a recirculation pump

(continued)

SURVEILLANCE REQUIREMENTS (continued)

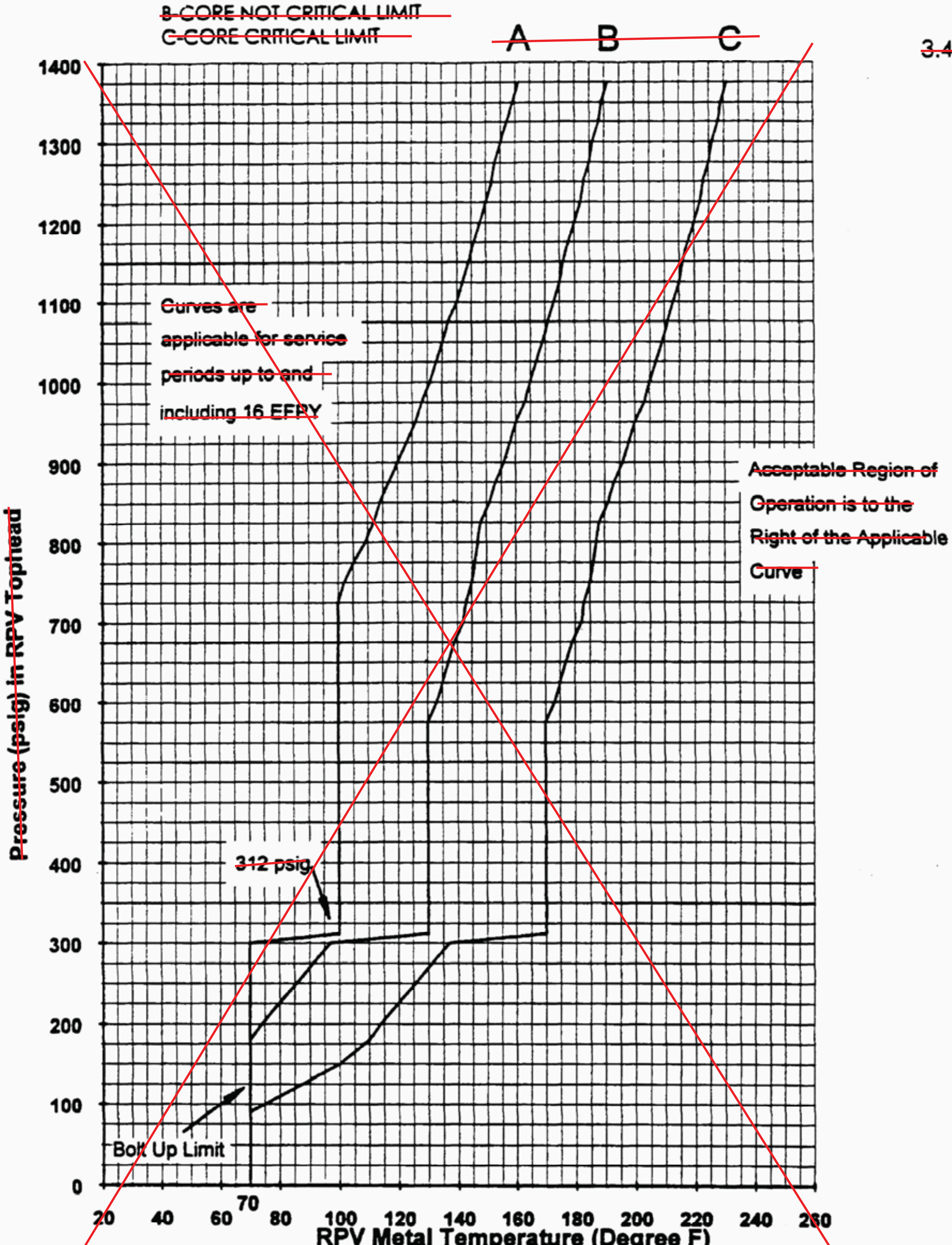
	SURVEILLANCE	FREQUENCY
SR 3.4.11.5	-------------------NOTE-------------------- Only required to be performed when tensioning the reactor vessel head bolting studs. ---	
	Verify reactor vessel flange and head flange temperatures are ~~≥ 70°F.~~ within the limits specified in the PTLR.	30 minutes
SR 3.4.11.6	-------------------NOTE-------------------- Not required to be performed until 30 minutes after RCS temperature ≤ 80°F in MODE 4. ---	
	Verify reactor vessel flange and head flange temperatures are ~~≥ 70°F.~~ within the limits specified in the PTLR.	30 minutes
SR 3.4.11.7	-------------------NOTE-------------------- Not required to be performed until 12 hours after RCS temperature ≤ 100°F in MODE 4. ---	
	Verify reactor vessel flange and head flange temperatures are ~~≥ 70°F.~~ within the limits specified in the PTLR.	12 hours

(continued)

SURVIELLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.11.8	--------------------NOTE-------------------- Only required to be met in single loop operation during increases in THERMAL POWER or recirculation loop flow with the operating recirculation pump not on high speed and THERMAL POWER < 36% of RTP. --- Verify the difference between the bottom head coolant temperature ~~and the RPV coolant temperature is ≤ 100°F.~~ within the limits specified in the PTLR.	Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow
SR 3.4.11.9	--------------------NOTE-------------------- Only required to be met in single loop operation during increases in THERMAL POWER or recirculation loop flow with the operating recirculation pump not on high speed, and THERMAL POWER < 36% of RTP, and the idle recirculation loop not isolated from the RPV. --- Verify the difference between the reactor coolant temperature in the recirculation loop not in operation and the RPV coolant temperature is ~~≤ 50°F.~~ within the limits specified in the PTLR.	Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow

Next page is 3.4-36.

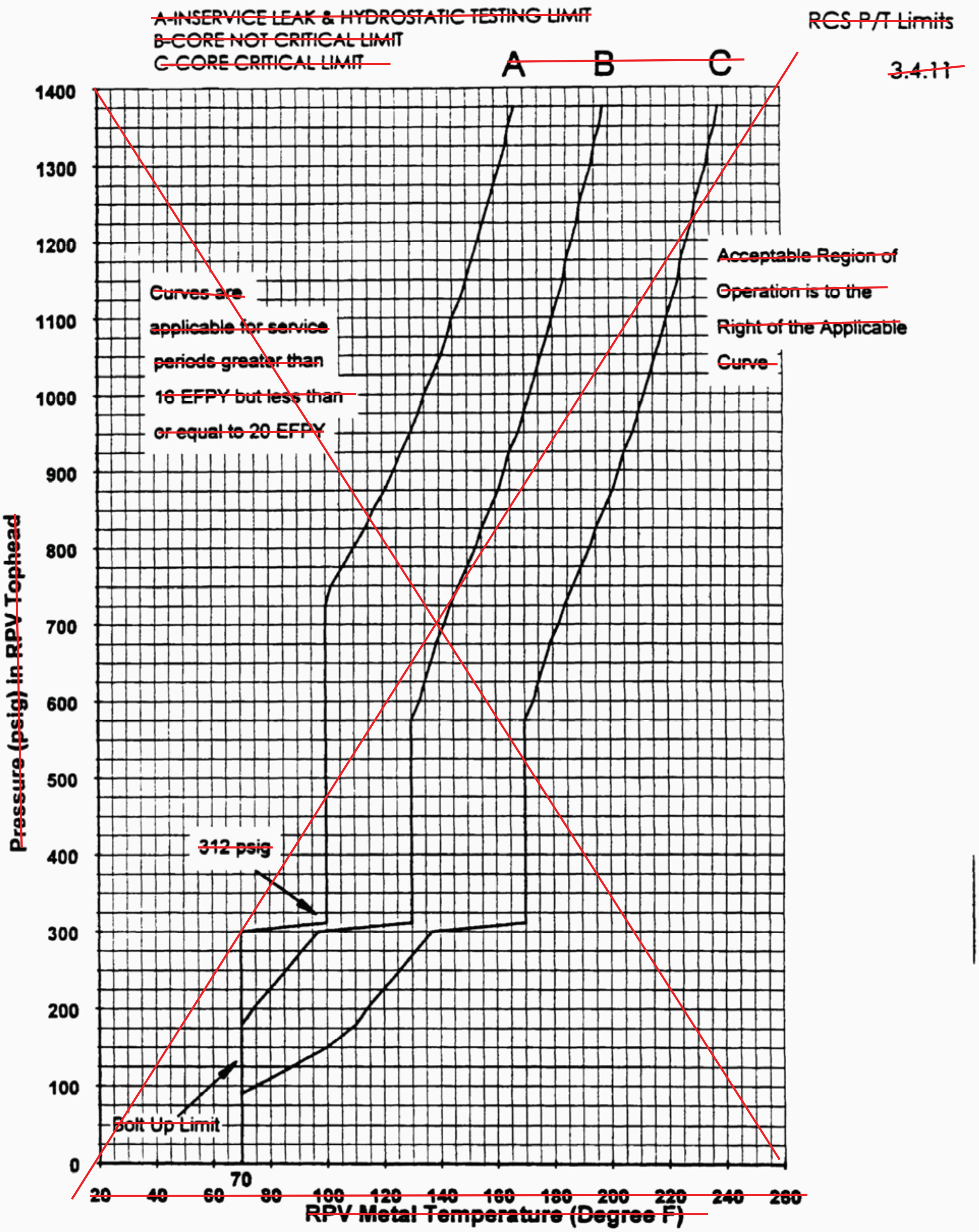


~~Minimum Reactor Vessel Metal Temperature vs Reactor Vessel Pressure~~

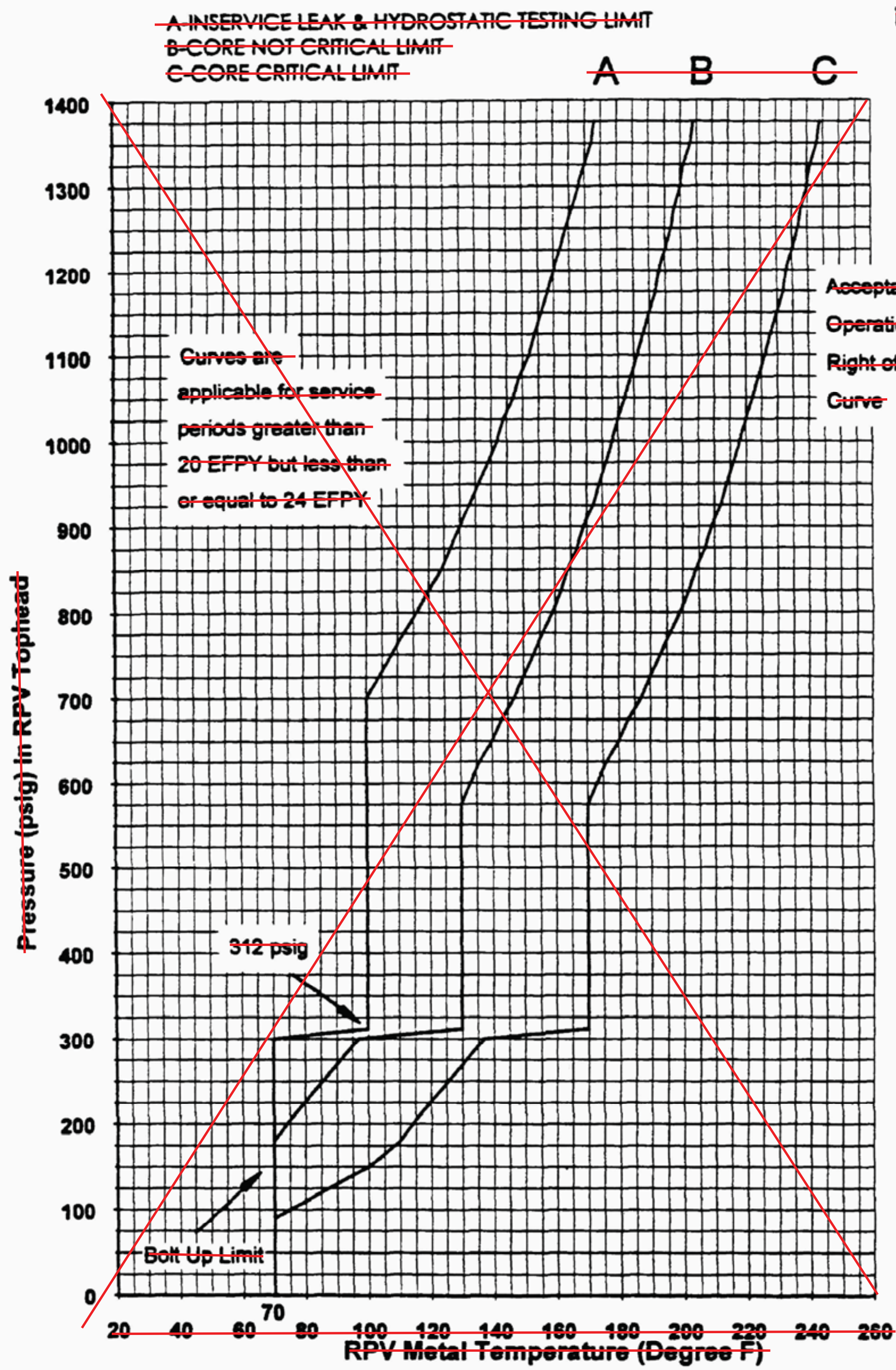
~~Figure 3.4.11-1 (page 1 of 5)~~

~~RCS P/T Limits~~

~~3.4.11~~



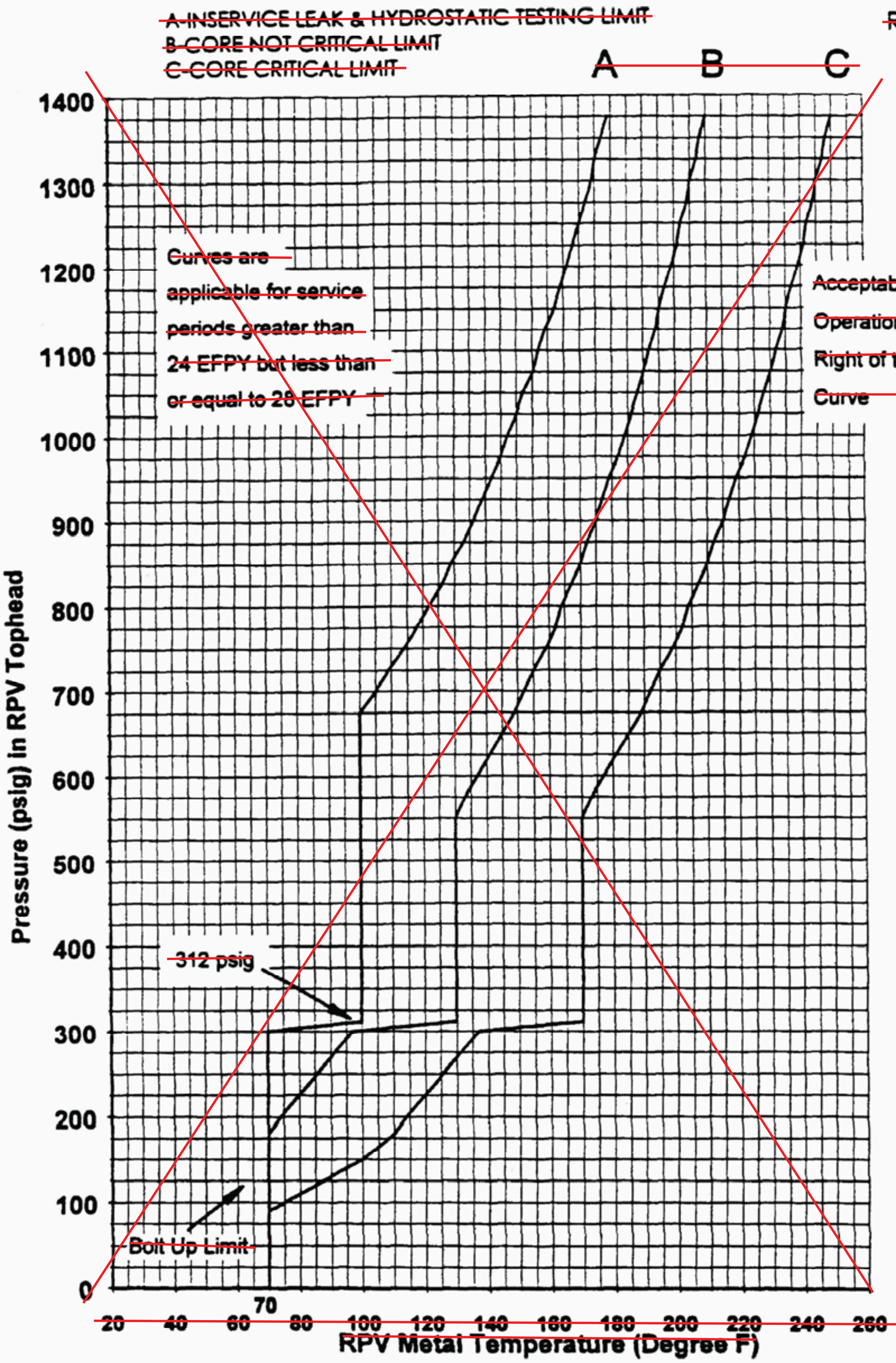
~~Minimum Reactor Vessel Metal Temperature vs Reactor Vessel Pressure~~
~~Figure 3.4.11-1 (page 2 of 5)~~



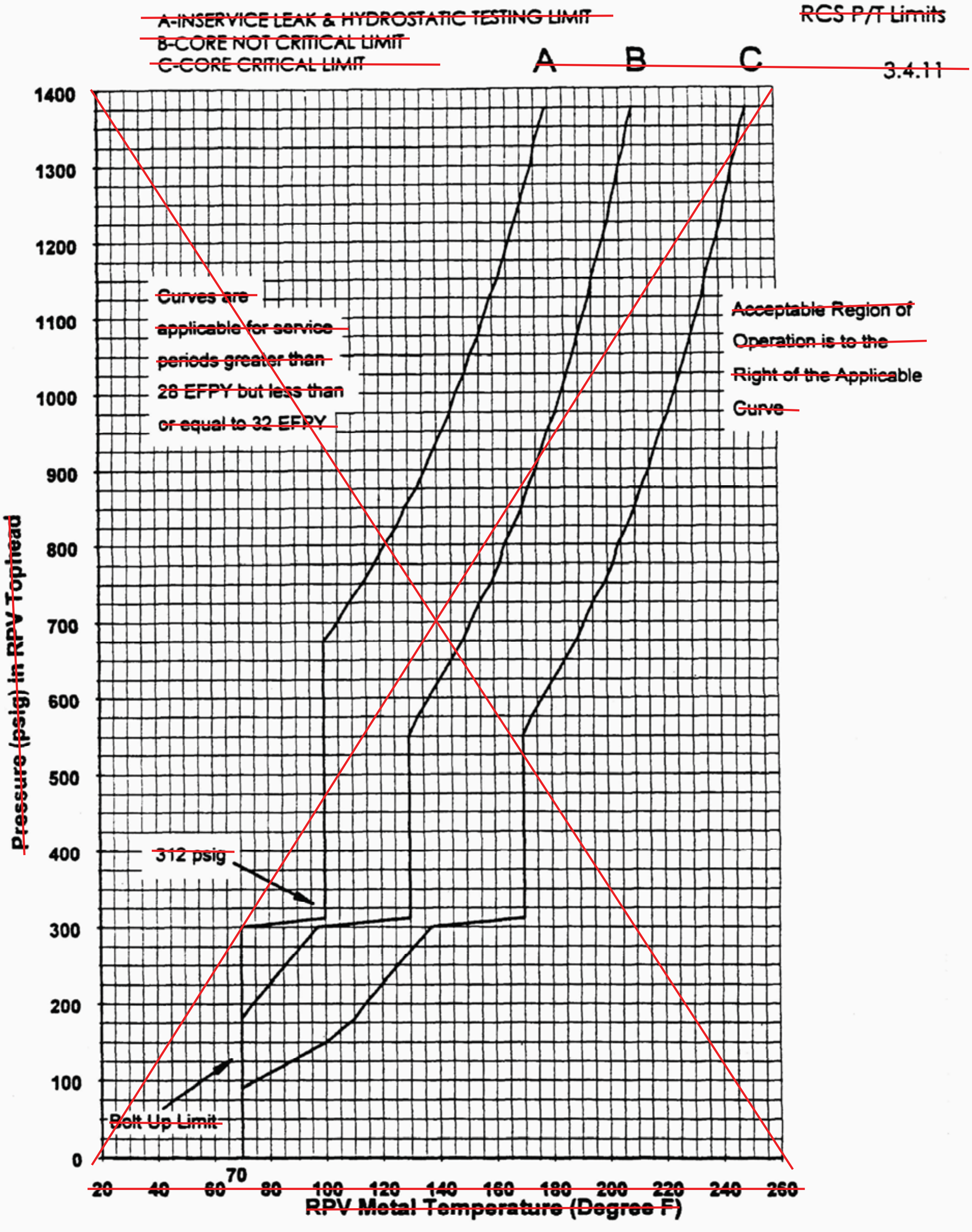
~~Minimum Reactor Vessel Metal Temperature vs Reactor Vessel Pressure~~
~~Figure 3.4.11-1 (page 3 of 5)~~

~~RCS P/T Limits~~

~~3.4.11~~



~~Minimum Reactor Vessel Metal Temperature vs Reactor Vessel Pressure~~
~~Figure 3.4.11-1 (page 4 of 5)~~



~~Minimum Reactor Vessel Metal Temperature vs Reactor Vessel Pressure~~
~~Figure 3.4.11-1 (page 5 of 5)~~

3.7 PLANT SYSTEMS

3.7.7 Main Turbine Bypass System

LCO 3.7.7

a. The Main Turbine Bypass System shall be OPERABLE with two Main Turbine Bypass Valves.

OR

b. The following limits are made applicable:

1. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR.

AND

2. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR.

APPLICABILITY: THERMAL POWER $\geq$ 70% RTP

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met or Main Turbine Bypass System is inoperable.	A.1 Satisfy the Requirements of the LCO or restore the Main Turbine Bypass System to OPERABLE status.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 70% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.7.7.1 Verify one complete cycle of each main turbine bypass valve.	31 days
SR 3.7.7.2 Perform a system functional test.	18 months

5.6.5 Core Operating Limits Report (COLR) (continued)

21. NEDE-33383-P, "GEXL97 Correlation Applicable to ATRIUM-10Fuel," Global Nuclear Fuel.

22. EMF-CC-074(P)(A), Volume 4, "BWR Stability Analysis Assessment of STAIF with Input from MICROBURN-B2", Siemens Power Corporation, Richland, WA.

23. EMF-2292(P)(A), "ATRIUM-10 Appendix K Spray Heat Transfer Coefficients", Siemens Power Corporation, Richland, WA.

24. NEDE-24011 -P-A, General Electric Standard Application for Reactor Fuel (GESTAR-II).

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.6 Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR)

a. RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:
   i) Limiting Conditions for Operation Section 3.4.11, "RCS Pressure and Temperature (P/T) Limits"
   ii) Surveillance Requirements Section 3.4.11, "RCS Pressure and Temperature (P/T) Limits"

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following document:
   i) NEDC-33178P-A, "GE Hitachi Nuclear Energy Methodology for Development of Reactor Pressure Vessel Pressure Temperature Curves" Revision 1, June 2009

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluence period and for any revision or supplement thereto.

Attachment 3

GNRO-2010/00056

Changes to Technical Specification Bases Pages
For Information Only

BASES

BACKGROUND (continued)

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of transition boiling 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.

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 fuel design criterion that an MCPR SL is to be established, such that at least 99.9% of the fuel rods in the core would not be expected to experience the onset of transition boiling.

The Reactor Protection System setpoints (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), in combination with other LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System water level, pressure, and THERMAL POWER level that would result in reaching the MCPR SL.

2.1.1.1 Fuel Cladding Integrity

The use of the fuel vendor's critical power correlations are valid for critical power calculations at pressures ≥ ~~785~~ 685 psig and core flows ≥ 10% of rated (Ref. 3, 5, and 6). For operation at low pressures or low flows, the fuel cladding integrity SL is established by a limiting condition on core THERMAL POWER, with the following basis:

> Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flow will always be > 4.5 psi. Analyses show that with a bundle flow of 28 x 10^3 lb/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus the bundle flow with a 4.5 psi driving head will be > 28 x 10^3 lb/hr. Full scale

(continued)

APPLICABLE SAFETY ANALYSES

2.1.1.1 Fuel Cladding Integrity (continued)

685

ATLAS test data taken at pressures from 14.7 psia to 800 psia indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER > ~~50% RTP~~. Thus a THERMAL POWER limit of ~~25% RTP~~ for reactor pressure < ~~785~~ psig is conservative. Because of the design thermal hydraulic compatibility of the reload fuel designs with the cycle 1 fuel, this justification and the associated low pressure and low flow limits remain applicable for future cycles of cores containing these fuel designs.

44.2% RTP (This is a simple ratio 50 x (3898/4408). There is no reference for this value.)

21.8% RTP (The fuel thermal monitoring threshold established at EPU RTP is [1.2 / (4408 MWt / 800 bundles) = 21.8% RTP].)

2.1.1.2 MCPR

The MCPR SL ensures sufficient conservatism in the operating MCPR limit that, in the event of an AOO from the limiting condition of operation, at least 99.9% of the fuel rods in the core would be expected to avoid boiling transition. The margin between calculated boiling transition (i.e., MCPR = 1.00) and the MCPR SL is based on a detailed statistical procedure that considers the uncertainties in monitoring the core operating state. One specific uncertainty included in the SL is the uncertainty inherent in the critical power correlation. Reference 2 describes the methodology used in determining the MCPR SL.

The calculated MCPR safety limit is reported to the customary three significant digits (i.e., X.XX); the MCPR operating limit is developed based on the calculated MCPR safety limit to ensure that at least 99.9% of the fuel rods in the core are expected to avoid boiling transition.

The fuel vendor's critical power correlations are based on a significant body of practical test data, providing a high degree of assurance that the critical power, as evaluated by the correlation, is within a small percentage of the actual critical power being estimated. As long as the core pressure and flow are within the range of validity of the correlations, the assumed reactor conditions used in defining the SL introduce conservatism into the limit because bounding high radial power factors and bounding flat local peaking distributions are used to estimate the number of rods in boiling transition. These conservatisms and the

(continued)

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Standby Liquid Control (SLC) System

BASES

BACKGROUND

The SLC System is designed to provide the capability of bringing the reactor, at any time in a fuel cycle, from full power and minimum control rod inventory (which is at the peak of the xenon transient) to a subcritical condition with the reactor in the most reactive xenon free state without taking credit for control rod movement. The SLC System satisfies the requirements of 10 CFR 50.62 (Ref. 1) on anticipated transient without scram (ATWS).

The SLC System consists of a boron solution storage tank, two positive displacement pumps, two explosive valves, which are provided in parallel for redundancy, and associated piping and valves used to transfer borated water from the storage tank to the reactor pressure vessel (RPV). The borated solution is discharged through the high pressure core spray system sparger.

APPLICABLE SAFETY ANALYSES

The SLC System is manually initiated from the main control room, as directed by the emergency operating procedures, if the operator believes the reactor cannot be shut down, or kept shut down, with the control rods. The SLC System is used in the event that not enough control rods can be inserted to accomplish shutdown and cooldown in the normal manner. A SLC injection is also credited in the LOCA dose analysis to buffer the post-accident suppression pool chemistry and prevent iodine re-evolution. The SLC System injects borated water into the reactor core to compensate for all of the various reactivity effects that could occur during plant operation. To meet this objective, it is necessary to inject a quantity of boron that produces the equivalent of a concentration of at least ~~660~~ 780 ppm of natural boron in the reactor core at 68°F. To allow for potential leakage and imperfect mixing in the reactor system, an additional amount of boron equal to 25% of the amount cited above is added (Ref. 2). The ~~temperature versus~~ concentration limits ~~in Figure 3.1.7-1~~ are calculated such that the required concentration is achieved accounting for dilution in the RPV with normal water level and including the water volume in the residual heat removal shutdown cooling piping and in the recirculation loop piping. This quantity of borated solution is the amount

(continued)

ACTIONS

A.1 ~~and A.2~~

~~When the boron concentration is in the Limited Operation region (between 15.2 weight percent and 28.5 weight percent), the SBLC System contains sufficient boron to perform its design basis functions. But the associated solution temperatures required to prevent precipitation of the boron from solution is potentially greater than the primary containment's ambient temperature. As a result, the non safety tank heaters may be required to maintain the tank~~

In this condition, the concentration must be restored to within limits in 8 hours. It is not necessary under this condition to enter Condition E for both SLC subsystems inoperable, since they are capable of performing their original design basis function. Because of the low probability of an ATWS event and that the SLC System capability still exists for vessel injection under this condition, the allowed Completion Time of 8 hours is acceptable and provides adequate time to restore concentration to within limits.

(continued)

ACTIONS

B.1
If the volume of the sodium pentaborate solution is less than 4,200 gallons, the volume must be restored to greater than or equal to 4,200 gallons within 8 hours. When in Condition B.1, it is not necessary to enter Condition E for both SLC subsystems inoperable. The subsystems are capable of performing their original design basis function. Because of the low probability of an ATWS event and that the SLC System capability still exists for vessel injection under this condition, the allowed Completion Time of 8 hours is acceptable and provides adequate time to restore the volume to within limits.

C.1
If the temperature of the sodium pentaborate solution is less than 45°F or greater than 150°F, the temperature must be restored to within limits within 8 hours. When in Condition C.1, it is not necessary to enter Condition E for both SLC subsystems inoperable. The subsystems are capable of performing their original design basis function. Because of the low probability of an ATWS event and that the SLC System capability still exists for vessel injection under this condition, the allowed Completion Time of 8 hours is acceptable and provides adequate time to restore the temperature to within limits.

~~A.1 and A.2 (continued)~~

~~temperatures above the precipitation temperature. As a result of this potential reliance on the heaters to maintain the solution temperature operation in the Limited Operation region is only allowed for up to 72 hours and SR 3.1.7.2 is required to be performed once per 4 hours. The SR 3.1.7.2 is performed once per 4 hours to compensate for the reduced range of acceptable temperatures to preclude precipitation at the higher concentrations while remaining below the upper temperature limit (Reference 3). It is not necessary in the Limited Operation region to declare both SLC subsystems inoperable, since they are capable of performing their design basis functions. Because the SLC System capability still exists for vessel injection under these conditions, the allowed Completion Time of 72 hours is acceptable and provides adequate time to restore concentration to within limits.~~

~~B.1~~ D.1

If one SLC subsystem is inoperable for reasons other than Conditions A, B or C, the inoperable subsystem must be restored to OPERABLE status within 7 days. ~~It is not necessary to enter this condition due to operation in the Limited Operation region.~~ In this condition, the remaining OPERABLE subsystem is adequate to perform the shutdown function. However, the overall reliability is reduced because a single failure in the remaining OPERABLE subsystem could result in reduced SLC System shutdown capability. The 7 day Completion Time is based on the availability of an OPERABLE subsystem capable of performing the intended SLC System function and the low probability of a Design Basis Accident (DBA) or severe transient occurring concurrent with the failure of the Control Rod Drive System to shut down the plant.

~~C.1~~ E.1

If both SLC subsystems are inoperable for reasons other than Conditions A, B or C, at least one subsystem must be restored to OPERABLE status within 8 hours. ~~It is not necessary to enter this condition due to operation in the Limited Operation region.~~ The allowed Completion Time of 8 hours is considered acceptable, given the low probability of a DBA or transient occurring

(continued)

ACTIONS

E.1 ~~C.1~~ (continued)

concurrent with the failure of the controls rods to shut down the reactor.

F.1 ~~D.1~~

If any Required Action and associated Completion Time 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 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1 and SR 3.7.1.2

SR 3.1.7.1 and SR 3.1.7.2 are 24 hour Surveillances, verifying certain characteristics of the SLC System (e.g., the volume and temperature of the borated solution in the storage tank), thereby ensuring the SLC System OPERABILITY without disturbing normal plant operation. These Surveillances ensure the proper borated solution and temperature, including the temperature of the pump suction piping, are maintained. Maintaining a minimum specified borated solution temperature is important to ensuring that the boron remains in solution and does not precipitate out in the storage tank or in the pump suction piping. Maintaining the temperature less than 150°F ensures the pump net positive suction head requirements for two pump operation and SLC System piping qualifications. The 24-hour Frequency of these SRs is based on operating experience that has shown there are relatively slow variations in the measure parameters of volume and temperature.

~~SR 3.1.7.1 is a 24 hour Surveillance to verify the volume of the borated solution in the storage tank. This Surveillance ensures the proper amount of sodium pentaborate (boron) solution is available to maintain the required minimum weight of 5800 pounds of boron in the solution. This required volume is identified as a required range of solution volumes ranging from 4281 gallons to 5088 gallons as a function of the boron concentration. The lower volume bound is the volume required to assure that the solution, at a concentration of 15.2 weight percent boron, will contain the 5800 pounds of boron approved by the NRC as the quantity conservatively needed for cold shutdown during an ATWS event. The upper bound on the required volume is limited by the tank volume of 5088 gallons (Reference 3). The 24 hour Frequency of this SR is based on operating experience that has shown there are relatively slow variations in the measured parameters.~~

~~SR 3.1.7.2~~

~~SR 3.1.7.2 is a 24 hour Surveillance to verify the temperature of the borated solution in the storage tank. When the boron concentration is ≤ 15.2 weight percent the corresponding saturation temperature is ≤ 70°F which is below the corresponding minimum allowable temperature of 75°F, this at least 5°F difference is maintained when the~~

(continued)

SURVEILLANCE REQUIREMENTS

~~SR 3.1.7.2 (continued)~~

~~boron concentration is > 15.2 weight percent. The upper temperature limit of 130°F is set to meet the pump net positive suction head requirements for two pump operation and to ensure the temperature is below the 150°F temperature rating of the SLC System piping (Reference 3).~~

~~This Surveillance ensures the proper boron solution temperature is maintained. Maintaining a minimum specified boron solution temperature is important in ensuring that the boron remains in solution and does not precipitate out in the storage tank or in the pump suction piping (Reference 3). The 24 hour Frequency of this SR is based on operating experience that has shown there are relatively slow variations in the measured parameters.~~

SR 3.1.7.3 and SR 3.1.7.5

The requirements of 10 CFR 50.62 are met by the use of a sodium pentaborate solution enriched in the boron-10 (B-10) isotope. SR 3.1.7.3 determines whether the sodium pentaborate concentration, in conjunction with the boron enrichment, is within limits to meet the requirements of 10 CFR 50.62. SR 3.1.7.5 ensures that the parameters used in the determination of sodium pentaborate concentration are within limits. The available solution volume is the solution volume above the pump suction penetration. This surveillance requires an examination of the sodium pentaborate solution by using chemical analysis to ensure the proper weight of B-10 exists in the storage tank. SR 3.1.7.5 must be performed anytime boron or water is added to the storage tank solution to establish that the weight of B-10 is within the specified limits. This SR must be performed anytime the solution temperature is restored to ≥45°F, to ensure no significant boron precipitation occurred. The 31 day Frequency of these surveillances is appropriate because of the relatively slow variation of boron concentration between surveillances.

~~SR 3.1.7.3 is a 24 hour Surveillance to verify the temperature of the pump suction piping. The minimum acceptable temperature is such that when the boron solution temperature is in the acceptable range, the boron concentration is ≤ 28.5 weight percent, and the pump suction piping at 70°F (which is below the corresponding minimum allowable temperature of 75°F) the SLC System will still be able to inject the required amount of solution without excessive precipitation. The upper temperature limit of 130°F is set to meet the pump net positive suction head requirements for two pump operation and to ensure the temperature is below the 150°F temperature rating of the SLC System piping. Maintaining a minimum specified pump suction piping temperature is important in ensuring that the boron remains in solution and does not precipitate out in the pump suction piping (Reference 3). The 24 hour Frequency of this SR is based on operating experience that has shown there is relatively slow variation in the measured parameter.~~

SR 3.1.7.4 and SR 3.1.7.6

SR 3.1.7.4 verifies the continuity of the explosive charges in the injection valves to ensure proper operation will occur if required. ~~Other administrative controls, such as those that limit the shelf life of the explosive charges,~~

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.7.4 and SR 3.1.7.6 (continued)

~~must be followed.~~ The 31 day Frequency is based on operating experience that has demonstrated the reliability of the explosive charge continuity.

SR 3.1.7.6 verifies each valve in the system is in its correct position, but does not apply to the squib (i.e., explosive) valves. Verifying the correct alignment for manual, power operated, and automatic valves in the SLC System flow path ensures that the proper flow paths will exist for system operation. A valve is also allowed to be in the nonaccident position, provided it can be aligned to the accident position from the control room, or locally by a dedicated operator at the valve controls. This is acceptable since the SLC System is a manually initiated system. This Surveillance does not apply to valves that are locked, sealed, or otherwise secured in position, since they were verified to be in the correct position prior to locking, sealing, or securing. This verification of valve alignment does not apply to valves that cannot be inadvertently misaligned, such as check valves. 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 positions. The 31 day Frequency is based on engineering judgment and is consistent with the procedural controls governing valve operation that ensure correct valve positions.

~~SR 3.1.7.5~~

~~This Surveillance requires an examination of the sodium pentaborate solution by using chemical analysis to ensure the proper concentration of boron exists in the storage tank. SR 3.1.7.5 must be performed anytime boron or water is added to the storage tank solution to establish that the boron solution concentration is within the specified limits. This Surveillance must be performed anytime the solution temperature is restored to ≥ 75°F after the solution temperature has been < 75°F, to ensure no significant boron precipitation occurred. The 31 day Frequency of this Surveillance is appropriate because of the relatively slow variation of boron concentration between surveillances.~~

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.7

1340

Demonstrating each SLC System pump develops a flow rate ≥ 41.2 gpm at a discharge pressure ≥ ~~1300~~ psig without actuating the pump's relief valve ensures that pump performance has not degraded during the fuel cycle. This minimum pump flow rate requirement ensures that, when combined with the sodium pentaborate solution concentration requirements, the rate of negative reactivity insertion from the SLC System will adequately compensate for the positive reactivity effects encountered during power reduction, cooldown of the moderator, and xenon decay. This test confirms one point on the pump design curve, and is indicative of overall performance. Such inservice inspections confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this Surveillance is in accordance with the Inservice Testing Program.

SR 3.1.7.8 ~~and SR 3.1.7.9~~

This Surveillance ensures

~~These Surveillances ensure~~ that there is a functioning flow path from the boron solution storage tank to the RPV, including the firing of an explosive valve. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of that batch successfully fired. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The pump and explosive valve tested should be alternated such that both complete flow paths are tested every 36 months, at alternating 18 month intervals. The Surveillance may be performed in separate steps to prevent injecting boron into the RPV. An acceptable method for verifying flow from the pump to the RPV is to pump demineralized water from a test tank through one SLC subsystem and into the RPV. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance test when performed at the 18 month Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

SURVEILLANCE REQUIREMENTS

~~SR 3.1.7.8 and~~ SR 3.1.7.9 ~~(continued)~~

Enriched sodium pentaborate solution is made by mixing granular, enriched sodium pentaborate with water. Isotopic tests on the sodium pentaborate solution to determine the actual B-10 enrichment must be performed once within 24 hours after boron is added to the solution in order to ensure that the B-10 enrichment is adequate. Enrichment testing is only required when boron addition is made since enrichment change cannot occur by any other processes.

~~Demonstrating that all heat traced piping between the boron solution storage tank and the suction inlet to the injection pumps is unblocked ensures that there is a functioning flow path for injecting the sodium pentaborate solution. An acceptable method for verifying that the suction piping is unblocked is to pump from the storage tank to the test tank and then draining and flushing the piping with demineralized water. The 18 month Frequency is acceptable since there is a low probability that the subject piping will be blocked due to precipitation of the boron from solution in the heat traced piping. This is especially true in light of the daily temperature verification of this piping required by SR 3.1.7.3. However, if, in performing SR 3.1.7.3, it is determined that the temperature of this piping has fallen below the specified minimum, SR 3.1.7.9 must be performed once within 24 hours after the piping temperature is restored ≥ 75°F after the piping temperature has been < 75°F.~~

REFERENCES

1. 10 CFR 50.62.
2. UFSAR, Section 9.3.5.3.
3. GNRI-91/00153, Issuance of Amendment No. 79 to Facility Operating License No. NPF-29 - Grand Gulf Nuclear Station, Unit 1, Regarding Standby Liquid Control System Technical Specifications, dated July 30, 1991.

BASES (continued)

APPLICABILITY

The APLHGR limits are primarily derived from fuel design evaluations and LOCA and transient analyses that are assumed to occur at high power levels. Design calculations and operating experience have shown that as power is reduced, the margin to the required APLHGR limits increases. This trend continues down to the power range of 5% to 15% RTP when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor (IRM) scram function provides prompt scram initiation during any significant transient, thereby effectively removing any APLHGR limit compliance concern in MODE 2. Therefore, at THERMAL POWER levels

21.8%

< ~~25%~~ RTP, the reactor operates with substantial margin to the APLHGR limits; thus, this LCO is not required.

ACTIONS

A.1

If any APLHGR exceeds the required limit, an assumption regarding an initial condition of the DBA and transient analyses may not be met. Therefore, prompt action is taken to restore the APLHGR(s) to within the required limit(s) such that the plant will be operating within analyzed conditions and within the design limits of the fuel rods. The 2 hour Completion Time is sufficient to restore the APLHGR(s) to within its limit and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the APLHGR out of specification.

B.1

If the APLHGR cannot be restored to within its required limit within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < ~~25%~~ RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < ~~25%~~ RTP in an orderly manner and without challenging plant systems.

21.8%

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

APLHGRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ ~~25%~~ 21.8% RTP and then every 24 hours thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution under normal conditions. The 12 hour allowance after THERMAL POWER ≥ ~~25%~~ 21.8% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

REFERENCES

1. UFSAR, Chapter 4.

2. UFSAR, Chapter 15, Appendix 15C.

3. UFSAR, Chapter 15, Appendix 15D.

4. XN-NF-80-19(P)(A), "Exxon Nuclear Methodology for Boiling Water Reactors, Neutronics Methods for Design and Analysis," Volume 1 (as supplemented).

5. XN-NF-80-19(A), "Exxon Nuclear Methodology for Boiling Water Reactors, ECCS Evaluation Model," Volume 2 (as supplemented).

6. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel (GESTAR)."

APPLICABLE SAFETY ANALYSES (continued)

The MCPR operating limits derived from the transient analysis are dependent on the operating core flow and power state ($MCPR_f$ and $MCPR_p$, respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Refs. 3, 4, and 5). Flow dependent MCPR limits are determined by steady state thermal hydraulic methods using the three dimensional BWR simulator code (Ref. 6) and the steady state thermal hydraulic code (Ref. 2). $MCPR_f$ curves are provided based on the maximum credible flow runout transient for Loop Manual operation. The result of a single failure or single operator error during Loop Manual operation is the runout of only one loop because both recirculation loops are under independent control.

Power dependent MCPR limits ($MCPR_p$) are determined by the three dimensional BWR simulator code and the one dimensional transient code (Ref. 7). The $MCPR_p$ limits are established for a set of exposure intervals. The limiting transients are analyzed at the limiting exposure for each interval. Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scram trips are bypassed, high and low flow $MCPR_p$ operating limits are provided for operating between ~~25%~~ 21.8% RTP and the previously mentioned bypass power level.

The MCPR satisfies Criterion 2 of the NRC Policy Statement.

LCO

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The MCPR operating limits are determined by the larger of the $MCPR_f$ and $MCPR_p$ limits.

APPLICABILITY

The MCPR operating limits are primarily derived from transient analyses that are assumed to occur at high power levels. Below ~~25%~~ RTP, the reactor is operating at a slow recirculation pump speed and the moderator void ratio is small. Surveillance of thermal limits below ~~25%~~ RTP is unnecessary due to the large inherent margin that ensures that the MCPR SL is not exceeded even if a limiting transient occurs.

21.8%

(continued)

BASES

APPLICABILITY (continued)

Studies of the variation of limiting transient behavior have been performed over the range of power and flow conditions. These studies encompass the range of key actual plant parameter values important to typically limiting transients. The results of these studies demonstrate that a margin is expected between performance and the MCPR requirements, and that margins increase as power is reduced to ~~25%~~ 21.8% RTP. This trend is expected to continue to the 5% to 15% power range when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor (IRM) provides rapid scram initiation for any significant power increase transient, which effectively eliminates any MCPR compliance concern. Therefore, at THERMAL POWER levels < ~~25%~~ 21.8% RTP, the reactor is operating with substantial margin to the MCPR limits and this LCO is not required.

ACTIONS

A.1

If any MCPR is outside the required limit, an assumption regarding an initial condition of the design basis transient analyses may not be met. Therefore, prompt action should be taken to restore the MCPR(s) to within the required limit(s) such that the plant remains operating within analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the MCPR(s) to within its limit and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the MCPR out of specification.

B.1

If the MCPR cannot be restored to within the required limit within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < ~~25%~~ 21.8% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < ~~25%~~ 21.8% RTP in an orderly manner and without challenging plant systems.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The MCPR is required to be initially calculated within 12 hours after THERMAL POWER is ≥ ~~25%~~ 21.8% RTP and then every 24 hours thereafter. It is compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The 12 hour allowance after THERMAL POWER reaches ≥ ~~25%~~ 21.8% RTP is acceptable given the large inherent margin to operating limits at low power levels.

SR 3.2.2.2

Because the transient analyses may take credit for conservatism in the control rod scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analyses. SR 3.2.2.2 determines the actual scram speed distribution and compares it with the assumed distribution. The MCPR operating limit is then determined based either on the applicable limit associated with scram times of LCO 3.1.4, "Control Rod Scram Times," or the realistic scram times. The scram time dependent MCPR limits are contained in the COLR. This determination must be performed and any necessary changes must be implemented within 72 hours after each set of control rod scram time tests required by SR 3.1.4.1, SR 3.1.4.2, and SR 3.1.4.4 because the effective scram speed distribution may change during the cycle or after maintenance that could affect scram times. The 72 hour Completion Time is acceptable due to the relatively minor changes in the actual control rod scram speed distribution expected during the fuel cycle.

REFERENCES

1. NUREG-0562, "Fuel Failures As A Consequence of Nucleate Boiling or Dry Out," June 1979.

2. NEDE-24011-P-A General Electric Standard Application for Reactor Fuel (GESTAR II).

3. UFSAR, Chapter 15, Appendix 15B.

4. UFSAR, Chapter 15, Appendix 15C.

5. UFSAR, Chapter 15, Appendix 15D.

6. NEDE-30130-P-A, Steady-State Nuclear Methods.

7. NEDO-24154, Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors.

APPLICABLE SAFETY ANALYSES (continued)

operating limit specified in the COLR. The analysis also includes allowances for short term transient operation above the operating limit to account for AOOs, plus an allowance for densification power spiking.

The LHGR limits are multiplied by the smaller of either the flow dependent LHGR factor ($LHGRFAC_f$) or the power dependent LHGR factor ($LHGRFAC_p$) corresponding to the existing core flow and power state to ensure adherence to the fuel mechanical design bases during the limiting transient. $LHGRFAC_f$'s are generated to protect the core from slow flow runout transients. A curve is provided based on the maximum credible flow runout transient for Loop Manual operation. The result of a single failure or single operator error during operation in Loop Manual is the runout of only one loop because both recirculation loops are under independent control. $LHGRFAC_p$'s are generated to protect the core from plant transients other than core flow increases. For GE fuel, the power- and flow-dependent LHGR factors are identical to the power- and flow-dependent MAPLHGR factors.

The LHGR satisfies Criterion 2 of the NRC Policy Statement.

LCO

The LHGR is a basic assumption in the fuel design analysis. The fuel has been designed to operate at rated core power with sufficient design margin to the LHGR calculated to cause a 1% fuel cladding plastic strain. The operating limit to accomplish this objective is specified in the COLR.

APPLICABILITY

The LHGR limits are derived from fuel design analysis that is limiting at high power level conditions. At core thermal power levels < ~~25%~~ RTP, the reactor is operating with a substantial margin to the LHGR limits and, therefore, the Specification is only required when the reactor is operating at ≥ ~~25%~~ RTP.

21.8%

ACTIONS

<u>A.1</u>

If any LHGR exceeds its required limit, an assumption regarding an initial condition of the fuel design analysis is not met. Therefore, prompt action should be taken to

(continued)

BASES

ACTIONS

A.1 (continued)

restore the LHGR(s) to within its required limit(s) such that the plant is operating within analyzed conditions and within the design limits of the fuel rods. The 2 hour Completion Time is normally sufficient to restore the LHGR(s) to within its limit and is acceptable based on the low probability of a transient or Design Basis Accident occurring simultaneously with the LHGR out of specification.

B.1

If the LHGR cannot be restored to within its required limit within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < ~~25%~~ RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < ~~25%~~ RTP in an orderly manner and without challenging plant systems.

21.8%

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

The LHGRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ ~~25%~~ RTP and then every 24 hours thereafter. They are compared with the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution under normal conditions. The 12 hour allowance after THERMAL POWER ≥ ~~25%~~ RTP is achieved is acceptable given the large inherent margin to operating limits at lower power levels.

21.8%

REFERENCES

1. UFSAR, Chapter 15.

2. UFSAR, Chapter 4.

3. NUREG-0800, "Standard Review Plan," Section 4.2, II.A.2(g), Revision 2, July 1981.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Average Power Range Monitor (APRM) (continued)

trip system logic channel (A1, A2, B1, and B2). Similarly, any Function 2.d or 2.f trip from any two unbypassed APRM/OPRM channels will result in a full trip from each Voter channel. Three of the four APRM/OPRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. In addition, to provide adequate coverage of the entire core, consistent with the design bases for APRM Functions 2.a, 2.b, and 2.d, at least 20 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM/OPRM channel. For the OPRM Upscale, Function 2.f, LPRMs are assigned to "cells" of four detectors. A minimum of 30 cells, each with a minimum of two LPRMs, must be OPERABLE for the OPRM Upscale Function 2.f to be OPERABLE.

EPU impact to proposed changes in the PRNMS LAR.

2.a. Average Power Range Monitor Neutron Flux — High, Setdown

For operation at low power (i.e., MODE 2), the Average Power Range Monitor Neutron Flux — High, Setdown Function is capable of generating a trip signal that prevents fuel damage resulting from abnormal operating transients in this power range. For most operation at low power levels, the Average Power Range Monitor Neutron Flux — High, Setdown Function will provide a secondary scram to the Intermediate Range Monitor Neutron Flux — High Function because of the relative setpoints.

With the IRMs at Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux — High, Setdown Function will provide the primary trip signal for a corewide increase in power.

No specific safety analyses take direct credit for the Average Power Range Monitor Neutron Flux — High, Setdown Function. However, this Function indirectly ensures that, before the reactor mode switch is placed in the run position, reactor power does not exceed ~~25%~~ RTP (SL 2.1.1.1) when operating at low reactor pressure and low core flow. Therefore, it indirectly prevents fuel damage during significant reactivity increases with THERMAL POWER ≤ ~~25%~~ RTP.

21.8%

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is ≤ ~~25%~~ RTP.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.f. Oscillation Power Range Monitor (OPRM) Upscale (continued)

Period-Based Detection algorithm. The remaining algorithms provide defense-in-depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the Period-Based Detection algorithm. The Allowable Value for the OPRM Upscale Period-Based Detection algorithm is specified in the COLR.

EPU impact to proposed changes in the PRNMS LAR.

The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs), which are combined into "cells" for evaluation by the OPRM algorithms.

26%

21%

The OPRM Upscale Function is required to be OPERABLE when the plant is at ≥ ~~24%~~ RTP, the region of power-flow operation where anticipated events could lead to thermal-hydraulic instability and related neutron flux oscillations. Within this region, the automatic trip is enabled when THERMAL POWER, as indicated by the APRM Simulated Thermal Power, is ~~≥ 29%~~ RTP and reactor core flow, as indicated by recirculation drive flow, is < 60% of rated flow, the operating region where actual thermal-hydraulic oscillations may occur. The lower bound, ~~24%~~ RTP, is chosen to provide margin in the unlikely event of loss of feedwater heating while the plant is operating below the ~~29%~~ automatic OPRM Upscale trip enable point. Loss of feedwater heating is the only identified event that could cause reactor power to increase into the region of concern without operator action.

26%

An OPRM Upscale trip is issued from an APRM/OPRM channel when the Period-Based Detection algorithm in that channel detects oscillatory changes in the neutron flux, indicated by the combined signals of the LPRM detectors in a cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the Growth-Rate or Amplitude-Based algorithms detect growing oscillatory changes in the neutron flux for one or more cells in that channel.

Three of the four channels are required to be OPERABLE. Each channel is capable of detecting thermal-hydraulic instabilities, by detecting the related neutron flux oscillations, and issuing a trip signal before the MCPR SL is exceeded.

There is no Allowable Value for this function.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

Reactor Vessel Water Level—High, Level 8 signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. The Reactor Vessel Water Level—High, Level 8 Allowable Value is specified to ensure that the MCPR SL is not violated during the assumed transient. The Function is bypassed when the reactor mode switch is not in the run position.

Four channels of the Reactor Vessel Water Level—High, Level 8 Function, with two channels in each trip system arranged in a one-out-of-two logic, are available and are required to be OPERABLE when THERMAL POWER is ≥ ~~25%~~ RTP to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. With THERMAL POWER < ~~25%~~ RTP, this Function is not required since MCPR is not a concern below ~~25%~~ RTP.

21.8%

6. Main Steam Isolation Valve—Closure

MSIV closure results in loss of the main turbine and the condenser as a heat sink for the Nuclear Steam Supply System and indicates a need to shut down the reactor to reduce heat generation. Therefore, a reactor scram is initiated on a Main Steam Isolation Valve—Closure signal before the MSIVs are completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. However, for the overpressurization protection analysis of Reference 2, the Average Power Range Monitor Fixed Neutron Flux—High Function, along with the S/RVs, limits the peak RPV pressure to less than the ASME Code limits. That is, the direct scram on position switches for MSIV closure events is not assumed in the overpressurization analysis. Additionally, MSIV closure is assumed in the transients analyzed in Reference 4 (e.g., low steam line pressure, manual closure of MSIVs, high steam line flow). The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the ECCS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

8.a, b. Scram Discharge Volume Water Level—High (continued)

in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

9. Turbine Stop Valve Closure, Trip Oil Pressure—Low

Closure of the TSVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TSV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Stop Valve Closure, Trip Oil Pressure—Low Function is the primary scram signal for the turbine trip event analyzed in Reference 4. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the End of Cycle Recirculation Pump Trip (EOC-RPT) System, ensures that the MCPR SL is not exceeded.

Turbine Stop Valve Closure, Trip Oil Pressure—Low signals are initiated by the electrohydraulic control (EHC) fluid pressure at each stop valve. Two independent pressure transmitters are associated with each stop valve. One of the two transmitters provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Stop Valve Closure, Trip Oil Pressure—Low channels, each consisting of one pressure transmitter. The logic for the Turbine Stop Valve Closure, Trip Oil Pressure—Low Function is such that three or more TSVs must be closed to produce a scram.

This Function must be enabled at THERMAL POWER ≥ ~~40% RTP~~ 35.4% RTP, which is the analytical limit. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, to consider this Function OPERABLE, the turbine bypass valves must remain shut at THERMAL POWER ≥ ~~40%~~ 35.4% RTP. The setpoint is feedwater temperature dependent as a result of the subcooling changes that affect the turbine first stage pressure/reactor power relationship. For RTP

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Turbine Stop Valve Closure, Trip Oil Pressure—Low (continued)

operation with feedwater temperature ≥ 420°F, an allowable setpoint based on turbine first stage pressure is provided for the bypass function. The allowable setpoint is reduced for RTP operation with feedwater temperature > 370°F and < 420°F.

The Turbine Stop Valve Closure, Trip Oil Pressure—Low Allowable Value is selected to be high enough to detect imminent TSV closure thereby reducing the severity of the subsequent pressure transient.

Eight channels of Turbine Stop Valve Closure, Trip Oil Pressure—Low Function, with four channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function if any three TSVs should close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is ≥ ~~40%~~ RTP. This Function is not required when THERMAL POWER is < ~~40%~~ RTP since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Fixed Neutron Flux—High Functions are adequate to maintain the necessary safety margins.

35.4%

10. Turbine Control Valve Fast Closure, Trip Oil Pressure—Low

Fast closure of the TCVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the transients that would result from the closure of these valves. The Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 4. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the EOC-RPT System, ensures that the MCPR SL is not exceeded.

Turbine Control Valve Fast Closure, Trip Oil Pressure—Low signals are initiated by the EHC fluid pressure at each control valve. There is one pressure transmitter associated

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

10. Turbine Control Valve Fast Closure, Trip Oil Pressure—Low (continued)

with each control valve, the signal from each transmitter being assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER ≥ ~~40%~~ 35.4% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, to consider this Function OPERABLE, the turbine bypass valves must remain shut at THERMAL POWER ≥ ~~40%~~ 35.4% RTP. The basis for the setpoint of this automatic bypass is identical to that described for the Turbine Stop Valve Closure, Trip Oil Pressure—Low Function.

The Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Allowable Value is selected high enough to detect imminent TCV fast closure.

Four channels of Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This Function is required, consistent with the analysis assumptions, whenever THERMAL POWER is ≥ ~~40%~~ 35.4% RTP. This Function is not required when THERMAL POWER is < ~~40%~~ 35.4% RTP since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Fixed Neutron Flux—High Functions are adequate to maintain the necessary safety margins.

11. Reactor Mode Switch—Shutdown Position

The Reactor Mode Switch—Shutdown Position Function provides signals, via the manual scram logic channels, that are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis, but it is retained for the RPS as required by the NRC approved licensing basis.

The reactor mode switch is a single switch with four channels, each of which inputs into one of the RPS logic channels.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.7.

21.8%

A restriction to satisfying this SR when < ~~25%~~ RTP is provided that requires the SR to be met only at ≥ ~~25%~~ RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < ~~25%~~ RTP. At low power levels, a high degree of accuracy is unnecessary because of the large inherent margin to thermal limits (MCPR and APLHGR). At ≥ ~~25%~~ RTP, the Surveillance is required to have been satisfactorily performed within the last 7 days in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above ~~25%~~ if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding ~~25%~~ RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

21.8%

21.8%

SR 3.3.1.1.3

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

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, SR 3.3.1.1.3 is not required to be performed when entering MODE 2 from MODE 1 since testing of the MODE 2 required IRM and APRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.13

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The functional testing of control rods, in LCO 3.1.3, "Control Rod OPERABILITY," and SDV vent and drain valves, in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlaps this Surveillance to provide complete testing of the assumed safety function.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 18 month Frequency.

SR 3.3.1.1.14

35.4%

This SR ensures that scrams initiated from the Turbine Stop Valve Closure, Trip Oil Pressure—Low and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ ~~40%~~ RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodology are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed at THERMAL POWER ≥ ~~40%~~ RTP to ensure that the calibration remains valid.

35.4%

If any bypass channel setpoint is nonconservative (i.e., the Functions are bypassed at ≥ ~~40%~~ RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve, Trip Oil Pressure—Low and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

The Frequency of 18 months is based on engineering judgment and reliability of the components.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1.1, SR 3.3.2.1.2, SR 3.3.2.1.3, and SR 3.3.2.1.4 (continued)

control rod block occurs. Proper operation of the RWL is verified by SR 3.3.2.1.1 which verifies proper operation of the two-notch withdrawal limit and SR 3.3.2.1.2 which verifies proper operation of the four-notch withdrawal limit. Proper operation of the RPC is verified by SR 3.3.2.1.3 and SR 3.3.2.1.4. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. As noted, the SRs are not required to be performed until 1 hour after specified conditions are met (e.g., after any control rod is withdrawn in MODE 2). This allows entry into the appropriate conditions needed to perform the required SRs. The Frequencies are based on reliability analysis (Ref. 7).

SR 3.3.2.1.5

The LPSP is the point at which the RPCS makes the transition between the function of the RPC and the RWL. This transition point is automatically varied as a function of power. This power level is inferred from the first stage turbine pressure (one channel to each trip system). These power setpoints must be verified periodically to be within the Allowable Values. If any LPSP is nonconservative, then the affected Functions are considered inoperable. Since this channel has both upper and lower required limits, it is not allowed to be placed in a condition to enable either the RPC or RWL Function. Because main turbine bypass steam flow can affect the LPSP nonconservatively for the RWL, the RWL is considered inoperable with any main turbine bypass valves open. The Frequency of 92 days is based on the setpoint methodology utilized for these channels.

SR 3.3.2.1.6

The analytical limit for the HPSP is 70%.

This SR ensures the high power function of the RWL is not bypassed when power is above the HPSP. The power level is inferred from turbine first stage pressure signals. Periodic testing of the HPSP channels is required to verify the setpoint to be less than or equal to the limit. Adequate margins in accordance with setpoint methodologies are included. If the HPSP is nonconservative, then the RWL is considered inoperable. Alternatively, the HPSP can be placed in the conservative condition (nonbypass). If placed

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.9

LCO 3.1.3 and LCO 3.1.6 may require individual control rods to be bypassed in RACS to allow insertion of an inoperable control rod or correction of a control rod pattern not in compliance with BPWS. With the control rods bypassed in the RACS, the RPC will not control the movement of these bypassed control rods. Individual control rods may also be required to be bypassed to allow continuous withdrawal for determining the location of leaking fuel assemblies, adjustment of control rod speed, or control rod scram time testing. To ensure the proper bypassing and movement of those affected control rods, a second licensed operator or other qualified member of the technical staff must verify the bypassing and movement of these control rods is in conformance with applicable analyses. As noted, only one bypassed control rod may be moved at a time. This restriction minimizes the potential rate of change of reactivity. Compliance with this SR allows the RPC and RWL to be OPERABLE with these control rods bypassed.

REFERENCES

1. UFSAR, Section 7.6.1.7.3.

2. UFSAR, Section 15.4.2.

3. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel" (latest approved revision).

4. "Modifications to the Requirements for Control Rod Drop Accident Mitigating Systems," BWR Owners Group, July 1986.

5. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.

6. NRC SER, Acceptance of Referencing of Licensing Topical Report NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel, Revision 8, Amendment 17," December 27, 1987.

7. NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988.

8. NEDC-33004P-A, "Licensing Topical Report Constant Pressure Power Uprate," Revision 4, July 2003.

BACKGROUND (continued)

system trips one of the two EOC-RPT breakers for each recirculation pump and the second trip system trips the other EOC-RPT breaker for each recirculation pump.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The TSV Closure, Trip Oil Pressure—Low and the TCV Fast Closure, Trip Oil Pressure—Low Functions are designed to trip the recirculation pumps from fast speed operation in the event of a turbine trip or generator load rejection to mitigate the neutron flux, heat flux, and pressure transients, and to increase the margin to the MCPR SL. The analytical methods and assumptions used in evaluating the turbine trip and generator load rejection, as well as other safety analyses that assume EOC-RPT, are summarized in References 2, 3, and 4.

To mitigate pressurization transient effects, the EOC-RPT must trip the recirculation pumps from fast speed operation after initiation of initial closure movement of either the TSVs or the TCVs. The combined effects of this trip and a scram reduce fuel bundle power more rapidly than does a scram alone, resulting in an increased margin to the MCPR SL. Alternatively, MCPR limits for an inoperable EOC-RPT as specified in the COLR are sufficient to mitigate pressurization transient effects. The EOC-RPT function is automatically disabled when turbine first stage pressure is 35.4% < 40% RTP.

EOC-RPT instrumentation satisfies Criterion 3 of the NRC Policy Statement.

The OPERABILITY of the EOC-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.1.3. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated EOC-RPT breakers. Each channel (including the associated EOC-RPT breakers) must also respond within its assumed response time.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

transmitter associated with each stop valve, and the signal from each transmitter is assigned to a separate trip channel. The logic for the TSV Closure, Trip Oil Pressure—Low Function is such that two or more TSVs must be closed to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ ~~40%~~ 35.4% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Turbine Stop Valve Closure, Trip Oil Pressure – Low (continued)

first stage pressure; therefore to consider this Function OPERABLE, the turbine bypass valves must remain shut at 35.4% ≥ ~~40%~~ RTP. Four channels of TSV Closure, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TSV Closure, Trip Oil Pressure—Low Allowable Value is selected high enough to detect imminent TSV closure.

This protection is required, consistent with the safety analysis assumptions, whenever THERMAL POWER is ≥ ~~40%~~ RTP with any recirculating pump in fast speed. Below ~~40%~~ RTP or with the recirculation in slow speed, the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor (APRM) Fixed Neutron Flux—High Functions of the Reactor Protection System (RPS) are adequate to maintain the necessary safety margins. 35.4%

The automatic enable setpoint is feedwater temperature dependent as a result of the subcooling changes that affect the turbine first stage pressure/reactor power relationship. For operation with feedwater temperature ≥ 420°F, an Allowable Value setpoint based on turbine first stage pressure is provided for the bypass function. The Allowable Value setpoint is reduced for operation with a feedwater temperature between 370°F and 420°F.

TCV Fast Closure, Trip Oil Pressure – Low

Fast closure of the TCVs during a generator load rejection results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, an RPT is initiated on TCV Fast Closure, Trip Oil Pressure—Low in anticipation of the transients that would result from the closure of these valves. The EOC-RPT decreases reactor power and aids the reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

<u>TCV Fast Closure, Trip Oil Pressure—Low</u> (continued)

Fast closure of the TCVs is determined by measuring the EHC fluid pressure at each control valve. There is one pressure transmitter associated with each control valve, and the signal from each transmitter is assigned to a separate trip channel. The logic for the TCV Fast Closure, Trip Oil Pressure—Low Function is such that two or more TCVs must be closed (pressure transmitter trips) to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ ~~40%~~ RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore to consider this Function OPERABLE, the turbine bypass valves must remain shut at ≥ ~~40%~~ RTP. Four channels of TCV Fast Closure, Trip Oil Pressure—Low, with two channels in 35.4% each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TCV Fast Closure, Trip Oil Pressure—Low Allowable Value is selected high enough to detect imminent TCV fast closure. 35.4%

This protection is required consistent with the analysis, whenever the THERMAL POWER is ≥ ~~40%~~ RTP with any recirculating pump in fast speed. Below ~~40%~~ RTP or with recirculation pumps in slow speed, the Reactor Vessel Steam Dome Pressure—High and the APRM Fixed Neutron Flux—High Functions of the RPS are adequate to maintain the necessary safety margins. The turbine first stage pressure/reactor power relationship for the setpoint of the automatic enable is identical to that described for TSV closure.

ACTIONS

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

(continued)

ACTIONS

B.1 and B.2 (continued)

sufficient channels are OPERABLE or in trip, such that the EOC-RPT System will generate a trip signal from the given Function on a valid signal and both recirculation pumps can be tripped from fast speed operation. This requires two channels of the Function, in the same trip system, to be OPERABLE or in trip, and the associated EOC-RPT fast speed breakers to be OPERABLE or in trip. Alternatively, Required Action B.2 requires the MCPR limit for inoperable EOC-RPT, as specified in the COLR, to be applied. This also restores the margin to MCPR assumed in the safety analysis.

The 2 hour Completion Time is sufficient for the operator to take corrective action, and takes into account the likelihood of an event requiring actuation of the EOC-RPT instrumentation during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2, Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1 and C.2

With any Required Action and associated Completion Time not met, THERMAL POWER must be reduced to < 40% RTP within 4 hours. Alternately, the associated recirculation pump fast speed breaker may be removed from service since this performs the intended function of the instrumentation. The allowed Completion Time of 4 hours is reasonable, based on operating experience, to reduce THERMAL POWER to < 40% RTP from full power conditions in an orderly manner and without challenging plant systems. 35.4%

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains EOC-RPT trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 5) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers is included as a part of this test, overlapping the LOGIC SYSTEM FUNCTIONAL TEST, to provide complete testing of the associated safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel would also be inoperable.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance test when performed at the 18 month Frequency.

SR 3.3.4.1.5

This SR ensures that an EOC-RPT initiated from the TSV Closure, Trip Oil Pressure—Low and TCV Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ ~~40%~~ RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from first stage pressure), the main turbine bypass valves must remain closed at THERMAL POWER ≥ ~~40%~~ RTP to ensure that the calibration remains valid. If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ ~~40%~~ RTP either due to open main turbine bypass valves or other reasons), the affected TSV Closure, Trip Oil Pressure—Low and TCV Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel considered OPERABLE.

35.4%

The Frequency of 18 months has shown that channel bypass failures between successive tests are rare.

(continued)

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

is not reached. In addition, this Function supports actions to ensure that Safety Limit 2.1.1.1 is not exceeded. (This Function closes the MSIVs prior to pressure decreasing below ~~785~~ 685 psig, which results in a scram due to MSIV closure, thus reducing reactor power to < ~~25%~~ 21.8% RTP.)

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

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

The Main Steam Line Pressure—Low Function is only required to be OPERABLE in MODE 1 since this is when the assumed transient can occur (Ref. 2).

This Function isolates the Group 1 valves.

1.c. Main Steam Line Flow—High

Main Steam Line Flow—High is provided to detect a break of the MSL and to initiate closure of the MSIVs. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The Main Steam Line Flow—High Function is directly assumed in the analysis of the main steam line break (MSLB) accident (Ref. 1). The isolation action, along with the scram function of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and offsite doses do not exceed the 10 CFR 50.67 limits.

The MSL flow signals are initiated from 16 transmitters that are connected to the four MSLs. The transmitters are arranged such that, even though physically separated from

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.2

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

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency is based on reliability analysis described in References 5 and 6.

SR 3.3.6.1.3

The calibration of trip units consists of a test to provide a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.6.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

For Function 1.c, Main Steam Line Flow - High, there is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology.

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

SR 3.3.6.1.4, SR 3.3.6.1.5, and SR 3.3.6.1.6

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

The Frequency of SR 3.3.6.1.4, SR 3.3.6.1.5, and SR 3.3.6.1.6 is based on the assumption of the magnitude of equipment drift in the setpoint analysis.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1 (continued)

Individual jet pumps in a recirculation loop typically do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

The deviations from normal are considered indicative of a potential problem in the recirculation drive flow or jet pump system (Ref. 2). Normal flow ranges and established jet pump flow and differential pressure patterns are established by plotting historical data as discussed in Reference 2.

The 24 hour Frequency has been shown by operating experience to be adequate to verify jet pump OPERABILITY and is consistent with the Frequency for recirculation loop OPERABILITY verification.

This SR is modified by two Notes. Note 1 allows this Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, since these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions appropriate for data collection and evaluation.

21.8% RTP. (Note: This value is conservatively re-scaled from 25% to be consistent with the EPU re-scaled values from 25% to 21.8% associated with the fuel thermal monitoring threshold.)

Note 2 allows this SR not to be performed when THERMAL POWER is ≤ ~~25% RTP.~~ During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data.

REFERENCES

1. UFSAR, Section 6.3.

2. GE Service Information Letter No. 330, "Jet Pump Beam Cracks," June 9, 1990.

3. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressure transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs) followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. 2). For the purpose of the analyses, six of the S/RVs are assumed to operate in the relief mode, and ~~seven~~ nine in the safety mode. The analysis results demonstrate that the design S/RV capacity is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the design basis event.

Reference 3 discusses additional events that are expected to actuate the S/RVs. From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above.

S/RVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

The safety function of ~~seven~~ nine S/RVs is required to be OPERABLE in the safety mode, and an additional six S/RVs (other than the ~~seven~~ nine S/RVs that satisfy the safety function) must be OPERABLE in the relief mode. The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure. In Reference 2, an evaluation was performed to establish the parametric relationship between the peak vessel pressure and the number of OPERABLE S/RVs. The results show that with a minimum of ~~seven~~ nine S/RVs in the safety mode and six S/RVs in the relief mode OPERABLE, the ASME Code limit of 1375 psig is not exceeded.

The S/RV setpoints are established to ensure the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve be set at or below vessel design pressure (1250 psig) and the highest safety valve be set so the total accumulated pressure does not exceed 110% of the design pressure for conditions. The transient evaluations in Reference 3 are based on these setpoints, but also include the additional uncertainties of ± 3% of the nominal setpoint to account for potential setpoint drift to provide an added degree of conservatism.

(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The Pressure Temperature Limits Report (PTLR) (Ref. 13)

~~Figure 3.4.11-1~~ contains P/T limit curves for normal operation (including heatup and cooldown), and inservice leak and hydrostatic testing.

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 (i.e., to the right of the applicable curve).

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure. Therefore, the LCO limits apply mainly to the vessel.

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 2).

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 3), 10 CFR 50, Appendix H (Ref. 4) and the UFSAR Reactor Materials Surveillance Program (Ref. 9, 10, 11). The operating P/T limit curves will be adjusted, as

(continued)

APPLICABLE SAFETY ANALYSES (continued)

are acceptance limits themselves since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of the NRC Policy Statement.

LCO

The elements of this LCO are:

a. RCS pressure and temperature are within the limits specified in ~~Figure 3.4.11-1~~ the PTLR and heatup or cooldown rate is ~~≤ 100°F in any one hour period during RCS heatup, cooldown, and inservice leak and hydrostatic testing.~~ within the limits specified in the PTLR.

b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is ~~≤ 100°F~~ within the limits specified in the PTLR during recirculation pump startup and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow.

c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel is ~~≤ 50°F~~ within the limits specified in the PTLR during pump startup and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow.

d. RCS pressure and temperature are within the criticality limits specified in ~~the applicable Figure 3.4.11-1~~ the PTLR based on the current Effective Fuel Power Year (EFPY) prior to achieving criticality.

e. The reactor vessel flange and the head flange temperatures is ~~≥ 70°F~~ within the limits specified in the PTLR when tensioning the reactor vessel head bolting studs.

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to nonductile failure.

The rate of change of temperature limits control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and inservice leak and

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.4.11.8 and SR 3.4.11.9 (continued)

Plant specific test data has determined that the bottom head is not subject to temperature stratification with natural circulation at power levels as low as 36% of RTP with any single loop flow rate when the recirculation pump is on high speed operation. Therefore, SR 3.4.11.8 and SR 3.4.11.9 have been modified by a Note that requires the Surveillance to be met only when THERMAL POWER or loop flow is being increased when the above conditions are not met. The Note for SR 3.4.11.9 further limits the requirement for this Surveillance to exclude comparison of the idle loop temperature if the idle loop is isolated from the RPV since the water in the loop cannot be introduced into the remainder of the reactor coolant system.

REFERENCES

1. 10 CFR 50, Appendix G.

2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.

3. ASTM E 185-82, "Standard Practice for Conducting Surveillance Tests For Light-Water Cooled Nuclear Power Reactor Vessels," July 1982.

4. 10 CFR 50, Appendix H.

5. Regulatory Guide 1.99, Revision 2, May 1988.

6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

7. NEDO-21778-A, "Transient Pressure Rises Affecting Fracture Toughness Requirements For BWRs," December 1978.

8. UFSAR, Section 15.4.4.

9. GNRI-96/00176, Amendment 127 Safety Evaluation

10. GNRI-96/00186, Amendment 127 Safety Evaluation, Correction

11. UFSAR, Section 5.3.1.6.1

12. GNRI-97/00139, Amendment 132 to the Operating License.

13. GGNS Pressure Temperature Limits Report, Revision 0

BACKGROUND (continued)

This Specification ensures that the performance of the primary containment, in the event of a DBA, meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions.

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage.

Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded.

The maximum allowable leakage rate for the primary containment (L_a) is 0.682% by weight of the containment and drywell air per 24 hours at the maximum peak containment pressure (P_a) of ~~11.5~~ 11.9 psig (Ref. 4).

Primary containment satisfies Criterion 3 of the NRC Policy Statement.

LCO

Primary containment OPERABILITY is maintained by limiting leakage to $\leq$ 1.0 L_a, except prior to the first unit startup after performing a required 10 CFR 50, Appendix J leakage test. At this time, the combined Type B and Type C leakage must be < 0.6 L_a, and the overall Type A leakage must be < 0.75 L_a. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those

(continued)

BACKGROUND (continued)

DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis.

APPLICABLE SAFETY ANALYSES

The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 0.682% by weight of the containment and drywell air per 24 hours at the calculated maximum peak containment pressure (P_a) of 11.9 ~~11.5~~ psig. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the secondary containment.

Primary containment air locks satisfy Criterion 3 of the NRC Policy Statement.

LCO

As part of the primary containment, the air lock's safety function is related to control of containment leakage rates following a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

The primary containment air locks are required to be OPERABLE. For each air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, both air lock doors must be OPERABLE, and the test connection valves must be OPERABLE in accordance with LCO 3.6.1.3. These normally closed manual isolation valves are considered OPERABLE when closed or when intermittently opened under administrative controls. The interlock allows only one air lock door to be open at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.7 (continued)

each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.1.7 overlaps this SR to provide complete testing of the safety function. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.8

11.9

The analyses in Reference 2 is based on leakage that is less than the specified leakage rate. Leakage through any single main steam line must be ≤ 100 scfh when tested at a pressure of ~~11.5~~ psig. Leakage through all four steam lines must be ≤ 250 scfh when tested at P_a (~~11.5~~ psig). The MSIV leakage rate must be verified to be in accordance with the leakage test requirements of Reference 3, as modified by approved exemptions. A Note is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2 and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required.

SR 3.6.1.3.9

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of Reference 2 is met.

This SR is modified by a Note that states these valves are only required to meet the combined leakage rate in MODES 1, 2, and 3 since this is when the Reactor Coolant System is

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Residual Heat Removal (RHR) Containment Spray System

BASES

BACKGROUND

The primary containment is designed with a suppression pool so that, in the event of a loss of coolant accident (LOCA), steam released from the primary system is channeled through the suppression pool water and condensed without producing significant pressurization of the primary containment. The primary containment is designed so that with the pool initially at the minimum water volume and the worst single failure of the primary containment heat removal systems, suppression pool energy absorption combined with subsequent operator controlled pool cooling will prevent the primary containment pressure from exceeding its design value. However, the primary containment must also withstand a postulated bypass leakage pathway that allows the passage of steam from the drywell directly into the primary containment airspace, bypassing the suppression pool. The primary containment also must withstand a low energy steam release into the primary containment airspace. The RHR Containment Spray System is designed to mitigate the effects of bypass leakage and low energy line breaks.

There are two redundant, 100% capacity RHR containment spray subsystems. Each subsystem consists of a suction line from the suppression pool, an RHR pump, a heat exchanger, and three spray spargers inside the primary containment (outside of the drywell) above the refueling floor. Dispersion of the spray water is accomplished by 350 nozzles in each subsystem.

The RHR containment spray mode will be automatically initiated, if required, following a LOCA.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses that predict the primary containment pressure response for a LOCA with the maximum allowable bypass leakage area.

0.8

The equivalent flow path area for bypass leakage has been specified to be ~~0.9~~ ft^2. The analysis demonstrates that with containment spray operation the primary containment pressure remains within design limits.

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the RHR Suppression Pool Cooling System removes heat from the suppression pool. The suppression pool is designed to absorb the sudden input of heat from the primary system. In the long term, the pool continues to absorb residual heat generated by fuel in the reactor core. Some means must be provided to remove heat from the suppression pool so that the temperature inside the primary containment remains within design limits. This function is provided by two redundant RHR suppression pool cooling subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each RHR subsystem contains a pump and two heat exchangers in series and is manually initiated and independently controlled. The two RHR subsystems perform the suppression pool cooling function by circulating water from the suppression pool through the RHR heat exchangers and returning it to the suppression pool. RHR service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the external heat sink.

The heat removal capability of one RHR subsystem is sufficient to meet the overall DBA pool cooling requirement to limit peak temperature to ~~185°F~~ 210°F for loss of coolant accidents (LOCAs) and transient events such as a turbine trip without bypass or a stuck open safety/relief valve (S/RV). S/RV leakage and Reactor Core Isolation Cooling System testing increase suppression pool temperature more slowly. The RHR Suppression Pool Cooling System is also used to lower the suppression pool water bulk temperature following such events.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break LOCAs. The analyses demonstrate that the heat removal capacity of the RHR Suppression Pool Cooling System is adequate to maintain the primary containment conditions within design limits. The suppression pool temperature is calculated to remain below the design limit.

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.3 Drywell Purge System

BASES

BACKGROUND

The Drywell Purge System ensures a uniformly mixed post accident containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration.

Extended Power Uprate

The drywell purge compressor also performs the function diluting the drywell source term with the containment and suppression pool environment by pressurizing the drywell and discharging the drywell source term through the drywell ~~suppression pool vents with the implementation of the Alternative Source Term (Reference 3)~~, this dilution of drywell source term is ~~no longer~~ credited in the Equipment Qualification analysis.

The Drywell Purge System is an Engineered Safety Feature and is designed to operate following a loss of coolant accident (LOCA) in post accident environments without loss of function. The system has two independent subsystems, each consisting of a compressor and associated valves, controls, and piping. Each subsystem is sized to pump 1000 scfm. Each subsystem is powered from a separate emergency power supply. Since each subsystem can provide 100% of the mixing requirements, the system will provide its design function with a worst case single active failure.

Following a LOCA, the drywell is immediately pressurized due to the release of steam into the drywell environment. This pressure is relieved by the lowering of the water level within the weir wall, clearing the drywell vents and allowing the mixture of steam and noncondensibles to flow into the primary containment through the suppression pool, removing much of the heat from the steam. The remaining steam in the drywell begins to condense. As steam flow from the reactor pressure vessel ceases, the drywell pressure falls rapidly. Both drywell purge compressors start automatically 30 seconds after a LOCA signal is received from the Emergency Core Cooling System instrumentation, but only when drywell pressure has decreased to within approximately 0.87 psi above primary containment pressure.

(continued)

ACTIONS

B.1 and B.2 (continued)

provided by one division of the hydrogen igniters. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. The verification may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two drywell purge subsystems inoperable for up to 7 days. Seven days is a reasonable time to allow two drywell purge subsystems to be inoperable because the hydrogen control function is maintained and ~~because of the low probability of the occurrence of a LOCA that would generate hydrogen in amounts capable of exceeding the flammability limit~~.

C.1

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

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates the associated channel will function properly. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 31 day Frequency is reasonable, based on operating experience.

SR 3.6.3.3.2

Operating each drywell purge subsystem from the control room for ≥ 15 minutes ensures that each subsystem is OPERABLE and

(continued)

ACTIONS

A.1

In the event the drywell is inoperable, it 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 the drywell OPERABLE during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring drywell OPERABILITY) occurring during periods when the drywell is inoperable is minimal. Also, the Completion Time is the same as that applied to inoperability of the primary containment in LCO 3.6.1.1, "Primary Containment."

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1.1

0.8

The analyses in Reference 2 are based on a maximum drywell bypass leakage. This Surveillance ensures that the actual drywell bypass leakage is less than or equal to the acceptable A/√k design value of ~~0.9~~ ft^2 assumed in the safety analysis. The testing is performed at a differential pressure of ≥ 3.0 psid with one airlock door open (the airlock door remaining open is changed for the performance of each required test) and the drywell bypass leakage is calculated from the measured leakage. As left drywell bypass leakage, prior to the first startup after performing a required drywell bypass leakage test, is required to be ≤ 10% of the drywell bypass leakage limit. At all other times between required drywell leakage rate tests, the acceptance criteria is based on design A/√k. At the design A/√k the containment temperature and pressurization response are bounded by the assumptions of

(continued)

BASES (continued)

APPLICABLEE SAFETY ANALYSES

The Drywell Vacuum Relief System must function in the event of a large break LOCA to control rapid weir wall overflow that could cause drag and impact loadings on essential equipment and systems in the drywell above the weir wall. The Drywell Vacuum Relief System is not required to assist in hydrogen dilution or to protect the structural integrity of the drywell following a large break LOCA. Furthermore, their passive operation (remaining closed and not leaking during drywell pressurization) is implicit in all of the LOCA analyses (Ref. 1).

The Drywell Vacuum Relief System satisfies Criterion 3 of the NRC Policy Statement.

LCO

The LCO ensures that in the event of a LOCA, two drywell post-LOCA and two drywell purge vacuum relief subsystems are available to mitigate the potential subsequent drywell depressurization. Each vacuum relief subsystem is OPERABLE when capable of opening at the required setpoint but is maintained in the closed position during normal operation.

APPLICABILITY

In MODES 1, 2, and 3, a Design Basis Accident could cause pressurization of primary containment. Therefore, Drywell Vacuum Relief System OPERABILITY is required during these MODES. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the Drywell Vacuum Relief System OPERABLE is not required in MODE 4 or 5.

ACTIONS

The ACTIONS are modified by a NOTE, which ensures appropriate remedial actions are taken, if necessary, if the drywell is rendered inoperable by inoperable drywell vacuum relief subsystems.

<u>A.1</u>

0.8

With one or more vacuum relief subsystems open, the subsystem must be closed within 4 hours. This assures that drywell leakage would not result if a postulated LOCA were to occur. The 4 hour Completion Time is acceptable, since the drywell design bypass leakage $(A/\sqrt{k})$ of ~~0.9~~ ft^2 is

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.7 Main Turbine Bypass System

BASES

BACKGROUND	The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is 30.4% of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Turbine Bypass System consists of three hydraulically operated combined stop and control valves. The bypass valves are controlled by the turbine-generator and Pressure Control System, as discussed in FSAR Section 7.7.1.5. Normally, the bypass control valves are held closed and the pressure regulator controls the turbine control valves, directing all steam flow to the turbine. If the speed control load restricts steam flow to the turbine, the pressure regulator controls system pressure by opening the bypass control valves. If the capacity of the bypass valves is exceeded while the turbine cannot accept an increase in steam flow, the system pressure will rise and the reactor protection system action will cause shutdown of the reactor.
APPLICABLE SAFETY ANALYSES	The Main Turbine Bypass System is assumed to function during the rod withdrawal error (RWE) at power event, as discussed in FSAR Section 15.4.2, loss of feedwater heating event (LOFWH), as discussed in FSAR Section 15.1.1 and the slow opening of the recirculation control valve events as described in FSAR Section 15.4.5. Opening the bypass valves during these events mitigates the increase in reactor vessel pressure, which affects the MCPR and LHGR during the event. Only the RWE and LOFWH events initiating from near RTP will open the bypass valves. The basis for the applicable power range of the Main Turbine Bypass System is the slow opening of the recirculation control valve. Two or more inoperable Main Turbine Bypass valves may result in LHGR and MCPR penalties.
LCO	Two of the three Main Turbine Bypass valves are required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause slow pressurization, such that the Safety Limit MCPR is not exceeded. With two or more Main Turbine Bypass valves inoperable, modifications to the LHGR limits (LCO 3.2.3) and the MCPR limits (LCO 3.2.2) may be applied to allow continued operation. Main Turbine Bypass valves are considered OPERABLE when they are capable of opening in response to increasing main steam line pressure. This response is within the assumption of the applicable analysis. The LHGR and MCPR limits for two or more inoperable Main Turbine Bypass valves are specified in the COLR.

BASES

APPLICABILITY	The Main Turbine Bypass System is required to OPERABLE at ≥ 70% RTP to ensure that the fuel cladding integrity safety limit and the cladding 1% plastic strain limit are not violated during the slow opening of the recirculation control valve event. As discussed in the Bases for LCO 3.2.2 and LCO 3.2.3, sufficient margin to these limits exists below 70% RTP. Additionally, the Main Turbine Bypass valves are not expected to open when the event initiates from below 70% RTP. Therefore, these requirements are only necessary when operating at or above this power.
ACTIONS	A.1 If the Main Turbine Bypass system is inoperable, or the LHGR and MCPR limits for two or more inoperable Main Turbine Bypass valves, as specified in the COLR, are not applied, the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status or adjust the LHGR and MCPR limits accordingly. The 2 hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of an event occurring during this period requiring two of the three Main Turbine Bypass valves. B.1 If the Main Turbine Bypass System cannot be restored to OPERABLE status or the LHGR and MCPR limits for two or more inoperable Main Turbine Bypass valves are not applied, THERMAL POWER must be reduced to < 70% RTP. As discussed in the Applicability section, operation at <70% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass system is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The 4 hour Completion Time is 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 Cycling each Main Turbine Bypass valve through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Therefore, the Frequency is acceptable from a reliability standpoint. SR 3.7.7.2 The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals, the valves will actuate to their required position. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 18 month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.
REFERENCES	None