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U.S. Nuclear Regulatory Commission
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SUSQUEHANNA STEAM ELECTRIC STATION
PROPOSED LICENSE AMENDMENT
NUMBERS 285 FOR UNIT 1 OPERATING LICENSE NO. NPF-14
AND 253 FOR UNIT 2 OPERATING LICENSE NO. NPF-22
CONSTANT PRESSURE POWER UPRATE **Docket Nos. 50-387**
PLA-6002 **and 50-388**

References: 1. U. S. Nuclear Regulatory Commission, Regulatory Guide 1.174 "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," November, 2002.

2. PPL Letter PLA-5931, Britt T. McKinney (PPL) to USNRC, "Susquehanna Steam Electric Station Proposed License Amendment Numbers 279 for Unit 1 Operating License No. NPF-14 and 248 for Unit 2 Operating License No. NPF-22 ARTS/MELLLA Implementation," dated November 18, 2005.

3. PPL Letter PLA-5963, Britt T. McKinney (PPL) to USNRC, "Susquehanna Steam Electric Station Proposed Amendment No. 281 to License NPF-14 and Proposed Amendment No. 251 to License NPF-22: Application for License Amendment and Related Technical Specification Changes to Implement Full-Scope Alternative Source Term in Accordance With 10 CFR 50.67," dated October 13, 2005.

4. PPL Letter PLA-5933, Britt T. McKinney to USNRC "Susquehanna Steam Electric Station Proposed Amendment No. 280 to Unit 1 Facility Operating License NPF-14 and Proposed Amendment No. 249 to Unit 2 Facility Operating License NPF-22: Revise Technical Specification 3.4.10 RCS Pressure and Temperature (P/T) Limits," dated October 5, 2005.

A001

Pursuant to 10 CFR 50.90, PPL Susquehanna LLC (PPL), hereby requests approval of amendments to the Susquehanna Steam Electric Station (SSES) Unit 1 and Unit 2 Operating Licenses (OLs) and Technical Specifications (TS), as described in the enclosure.

The proposed change would increase the maximum power level authorized by Section 2.C (1) from 3489 megawatts thermal (MWt) to 3952 MWt, an approximate 13 percent increase in thermal power. The proposed Constant Pressure Power Uprate (CPPU) represents an increase of approximately 20 percent above the Original Licensed Thermal Power (OLTP).

NRC approval of the requested increase in reactor thermal power level would allow PPL to implement operational changes to generate and supply a higher steam flow to the turbine generator. Higher steam flow is accomplished by increasing the reactor power along specified control rod and core flow lines. This increase in steam flow will enable increasing the electrical output of the plant.

As part of the Susquehanna CPPU request, PPL is proposing the following changes to the licensing basis:

1. Modification of the Standby Liquid Control System for single pump operation and use of enriched Boron,

2. Change of the Local Power range Monitor (LPRM) Technical Specification calibration interval,

3. Installation of a manually operated valve in the Ultimate Heat Sink (UHS) and a UHS analysis methods change, and

4. A containment analysis methods change

5. Addition of a Technical Specification to "3.7 Plant Systems," namely "3.7.8 Main Turbine Pressure Regulation System." Note that the new Technical Specification has been patterned on a similar Technical Specification "3.7.6 Main Turbine Bypass System."

The descriptions and technical evaluations of these proposed changes are contained in the enclosure.

As demonstrated in the enclosed evaluation, the proposed amendments do not involve a significant hazard consideration.

PPL plans to implement the first step of the uprate (approximate 7 % increase) for Unit 2 before restart from the refueling outage currently planned for the Spring 2007. Therefore, to support the PPL schedule for the first power uprate step, and for subsequent reload core design and outage planning, PPL requests that the proposed changes be approved by June 30, 2007.

Implementation of the first step of the uprate is planned to be completed within 120 days from startup (entry into Mode 2) following the Spring refueling outages in 2007 for Unit 2; and 2008 for Unit 1. The remaining portion of the uprate is planned to be implemented within 120 days from startup following the Spring 2009 Refueling Outage for Unit 2; and 2010 for Unit 1.

The enclosure to this letter contains PPL's evaluation of this proposed change. Included are a description of the proposed changes, technical analysis of the changes, regulatory safety analysis of the change (No Significant Hazards Consideration and the Applicable Regulatory Requirements/Criteria), and environmental consideration.

Attachment 1 is a mark-up of the Technical Specifications and the Operating License, showing the proposed changes.

Attachment 2 is a mark-up of the associated Technical Specification Bases, provided for information.

Attachment 3 contains a Supplemental Environmental Report supporting a conclusion of no significant impact.

The technical bases for this request follows the guidelines contained in General Electric (GE) Licensing Topical Reports (LTR) NEDC-33004P-A, "Constant Pressure Power Uprate" (CLTR). NRC has approved use of this LTR for reference as a basis for a power uprate license amendment request with the exception of the CLTR's proposed elimination of large transient testing. Attachment 4 contains the Power Uprate Safety Analysis Report (PUSAR). The PUSAR is an integrated summary of the results of the safety analysis and evaluations performed specifically for the SSES CPPU. The PUSAR contains information, which GE and which AREVA NP, Inc. (referred to throughtout the remainder of this request as Framatome ANP, Inc.) consider proprietary. GE requests and Framatome ANP, Inc. requests that their respective proprietary information be withheld from public disclosure in accordance with 10 CFR 2.390(a)4 and 9.17(a)4.

Affidavits supporting these requests are included with Attachment 5.

A non-proprietary version of the report is provided in Attachment 6.

Attachment 7 provides a list of completed and currently planned modifications for CPPU implementation. These modifications will be implemented during five refueling outages [Spring Outage 2006 through the Spring Outage 2010]. Modifications performed during the Spring 2006 Outage (U1-14) and Spring 2008 Outage (U1-15) will allow for an approximate 7 % increase in Unit 1 CLTP. Modifications performed in the Spring 2007 Outage (U2-13) will allow for an approximate 7 % increase in Unit 2 CLTP. Modifications performed during the Spring 2009 Unit 2 Outage (U2-14) and the Spring 2010 Unit 1 Outage (U1-16) will allow for the remaining approximate 7 % increase in Units 2 and 1 CLTP, respectively.

The amount of the additional 7% which can be used will be dependent on atmospheric conditions, since the SSES generators will become the component which limits electrical generation. Reactor power will be manipulated to maintain a maximum generator output, therefore the CPPU licensed core thermal power will only be achieved during hot summer conditions.

The list of modifications in Attachment 7 are planned actions, which do not constitute regulatory commitments by PPL. The modifications listed in Attachment 7 are being implemented in accordance with the requirements of 10 CFR 50.59 and do not require NRC review and approval.

Attachment 8 provides the Startup Testing plan, which specifies the EPU testing at the power levels listed above, in the description of Attachment 8, and a comparison of Initial Startup Testing and EPU Testing. The only large transient test that PPL proposes to perform is a condensate pump trip. Attachment 8 includes a justification for exceptions to the other large transient tests. This enclosure supplements PUSAR Section 10.4.

Attachment 9 provides a summary of the PPL Flow Induced Vibration Extent of Condition (EOC) completed or currently planned reviews to address the potential for increased flow-induced vibration. PPL has actively participated in the BWR Owners Group EPU Committee.

Attachment 10 is a summary of the actions completed or currently planned to ensure the integrity of the steam dryer at CPPU conditions. Attachment 10 contains a summary of the current condition of the dryer, the 1986 dryer instrumented test report, and an evaluation of the current dryer stresses and margins. It includes an assessment of the potential for acoustic resonances, based on calculated and scale model testing. Attachment 10 also provides the plan for completing the dryer startup monitoring.

Attachment 11 is a summary of grid impact studies which demonstrate that the CPPU will not have a significant effect on the reliability or operating characteristics of SSES or on the offsite system.

Attachment 12 is a markup of the review matrices contained in NRC's "Review Standard for Extended Power Uprates" (RS-001), with cross-references to the CLTR, as well as the SSES PUSAR and FSAR.

Attachment 13 provides a mark-up of the BWR Template Safety Evaluation contained in RS-001. Note that the PPL FSAR includes an evaluation of SSES with respect to the General Design criteria. The Attachment 13 mark-up of the BWR Template Safety Evaluation includes only the changes to the relevant Evaluations or Conclusions of the Inserts. Unchanged material is not included.

Attachment 14 is the non-proprietary version of the Steam Dryer Structural Evaluation.

This license amendment request, while not being submitted as a risk informed licensing action as discussed in Regulatory Guide 1.174, has been evaluated from a risk perspective, as described in Section 10.5 of the PUSAR .

PPL has previously requested approval of amendments to the SSES Technical Specifications to permit implementation of Average Power Range Monitor/Rod Block Monitor/Technical Specifications/Maximum Extended Load Line Limit Analysis (ARTS/MELLLA), in Reference 2. ARTS/MELLLA supports operation of SSES in a core flow region, which is above the rated rod line. Implementation of ARTS will increase plant efficiency by updating the thermal limits requirements. Approval of ARTS/MELLLA is necessary to support implementation of EPU for the first approximate 7 % increase in CLTP for each unit.

PPL has also previously requested approval of amendments to Technical Specifications for a full scope application of an Alternative Source Term (Reference 3). Reference 3 evaluations were performed at the CPPU power level. The CPPU was analyzed and the PUSAR was prepared based on AST methodology. The results indicate that offsite and control room doses are within the regulatory limits. This CPPU submittal includes a change in the required volume of sodium pentaborate solution, which bounds the change in volume required for CPPU operation. Approval of AST is necessary to support implementation of EPU for the first approximate 7 % increase in CLTP for each unit.

PUSAR Section 3.2.1, "Reactor Vessel Fracture Toughness," states that the Technical Specification Pressure-Temperature (P-T) Curves have been revised. PPL modified the P-T curves for the reactor coolant system to accommodate CPPU conditions. PPL submitted revised P-T curves in Reference 4 for the current 40 year licensed life of the units. PPL will provide the technical bases for the P-T curves for the renewed license period at CPPU conditions for the planned License Renewal Application.

There are no regulatory commitments associated with the proposed changes.

The need for the changes has been discussed with the SSES NRC Project Manager.

The proposed changes have been reviewed by the SSES Plant Operations Review Committee and by the Susquehanna Review Committee. In accordance with 10 CFR 50.91(b), PPL is providing the Commonwealth of Pennsylvania with a copy of this proposed License Amendment request.

If you have any questions or require additional information, please contact Mr. John M. Oddo at (610) 774-7596.

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

Executed on: 3-28-06

B. T. McKinney

B. T. McKinney

Enclosure:
PPL Susquehanna Evaluation of the Proposed Changes

Attachments:

Attachment 1	Proposed Technical Specification Changes (Mark-up)
Attachment 2	Changes to Technical Specifications Bases Pages (Mark-up, Provided for Information)
Attachment 3	Supplemental Environmental Report
Attachment 4	PUSAR (GE Proprietary, Framatome Proprietary and Affidavits)
Attachment 5	GE and Framatome ANP Affidavits
Attachment 6	PUSAR (Non-proprietary)
Attachment 7	List of Planned Modifications
Attachment 8	Startup Testing
Attachment 9	Flow Induced Vibration Piping/Components Evaluation
Attachment 10	Steam Dryer Structural Evaluation
Attachment 11	Grid Stability and Evaluation
Attachment 12	RS-001 – Standard Review Plan Correlation Matrices
Attachment 13	RS-001 – Safety Evaluation Template
Attachment 14	Steam Dryer Structural Evaluation (Non-Proprietary)

Copy: NRC Region I
Mr. A. Blamey, NRC Sr. Resident Inspector
Mr. R. V. Guzman, NRC Project Manager
Mr. R. Janati, DEP/BRP

ENCLOSURE TO PLA-6002

PPL SUSQEHANNA EVALUATION OF PROPOSED CHANGES TO

UNIT 1 AND UNIT 2 OPERATING LICENSES AND TECHNICAL SPECIFICATIONS FOR EXTENDED POWER UPRATE

PPL Evaluation

SUBJECT: PPL SUSQUEHANNA EVALUATION OF PROPOSED CHANGES TO UNIT 1 AND UNIT 2 OPERATING LICENSES AND TECHNICAL SPECIFICTIONS FOR EXTENDED POWER UPRATE (EPU) OPERATION

1. DESCRIPTION

Extended Power Uprate

The proposal would increase the Susquehanna Steam Electric Station's (SSES) licensed thermal power to 3952 Megawatts Thermal (MWt), which is 20 percent above the original Rated Thermal Power (RTP) of 3293 MWt, and approximately 13 percent above the current RTP of 3489 MWt.

NRC approval of the requested increase in reactor thermal power level will allow PPL to implement operational changes to generate and supply a higher steam flow to the turbine-generator. Higher steam flow is accomplished by increasing the reactor power along specified control rod and core flow lines. This increase in steam flow will enable increasing the electrical output of the plant.

The technical bases for this request follows the guidelines contained in the NRC-Approved GE Nuclear Energy (GENE) Licensing Topical Report (LTR) for Extended Power Uprate (EPU) Safety Analysis, NEDC-33004P-A "Constant Pressure Power Uprate" (CLTR) (Reference 1).

The proposed amendments include supporting changes to the Unit 1 and Unit 2 Operating Licenses and Technical Specifications necessary to implement the increased power level.

As part of the PPL EPU request, PPL is also proposing the following changes to the licensing basis:

1. Modification of the Standby Liquid Control System for single pump operation and use of enriched Boron,
2. Change of the Local Power Range Monitor (LPRM) Technical Specification calibration interval,
3. Installation of a manually operated valve in the Residual Heat Removal Service Water (RHRSW) and Ultimate Heat Sink Systems and a methods change, and
4. A containment analysis methods change

PPL proposes to perform the following revisions:

Standby Liquid Control System Technical Specification Change

The proposal would change the Standby Liquid Control (SLC) system Technical Specification 3.1.7. The proposed change is required to support the planned Susquehanna Steam Electric Station (SSES) Constant Pressure Power Uprate (CPPU). In support of the uprate, the SSES ATWS evaluation was re-analyzed to demonstrate continued compliance with 10 CFR 50.62.

To support the extended power uprate, PPL proposes to use a sodium pentaborate solution with a higher enrichment. With a higher enrichment, a lower solution weight-percent, lower concentrations, and lower tank volume are required. In addition, with the replacement of the existing SLC solution, system operation can change from two pumps, to a single pump. This will allow for a reduction in the required pump flow and discharge pressure, due to a lower system back pressure.

LPRM Calibration Interval Technical Specification SR Frequency Change

The proposed change would revise the calibration frequency requirement for the Local Power Range Monitors (LPRMs) from 1000 MWD/MT to 2000 MWD/MT average core exposure. By extending the LPRM calibration frequency, this surveillance may be better scheduled to coincide with other LPRM testing and control rod sequence exchanges. In addition, this will reduce operating time on the Traversing Incore Probe (TIP) system potentially resulting in the need for fewer repairs in a high radiation area. The time Primary Containment Isolation TIP Ball Valves are open will be further reduced.

Residual Heat Removal Service Water (RHR Service Water) Ultimate Heat Sink System Technical Specification and Methods Change

PPL proposes to add a manual spray bypass isolation valve to mitigate the effects of a failure of an existing spray array bypass isolation valve to close for the design basis event at CPPU conditions. It is also proposed that the small spray arrays be used to dissipate heat in the event that the large spray array valves fail to open for the design basis event at CPPU conditions. The manual spray array isolation valves and the small spray arrays are credited in the Ultimate Heat Sink (UHS) safety analysis which is performed to demonstrate that the UHS will maintain a maximum design temperature of 97°F following a design basis LOCA in one unit and concurrent safe shutdown of the other unit under CPPU conditions.

The new manual spray array bypass line valve on each spray loop is being installed in a valve vault for physical protection. Each valve will be capable of being operated from outside the vault with the use of a reach rod and a detachable valve handle that will be staged in a specific location. No other special tools are required for operation of the new valves.

PPL proposes to modify the Residual Heat Removal Service Water (RHRSW) and UHS Technical Specification 3.7.1 to add the manual spray array bypass isolation valves and small spray array isolation valves. In support of the proposed CPPU, re-evaluation of the UHS performance analysis was required. Re-evaluation of the UHS response for the design basis event was performed using the SSES Current Licensing Basis methodology. However, an alternate analytical element was employed for the calculation of decay heat. This element is not part of the SSES current UHS analytical bases. The revised analysis used decay heat values calculated per the ANSI/ANS 5.1-1979 decay heat model, with a two-sigma uncertainty instead of the Branch Technical Position ASB 9-2 model which is the current SSES licensing basis. NRC review and approval is requested for the use of this element because it is a change to the current methodology which results in less conservative results.

Containment Analysis Methods Change

In support of the proposed CPPU, re-evaluation of the DBA-LOCA containment analyses was required. Re-evaluation of the associated long-term response analyses were performed by General Electric with the SHEX code, which is the SSES Current Licensing Basis methodology. With respect to the revised analysis, two alternate analytical elements were employed. These alternate elements are consistent with GE's current industry practices for re-evaluating containment response. However, they are not part of the SSES current containment analytical bases (Current Licensing Basis). These elements are: 1) crediting the presence of passive heat sinks; and 2) the use of the ANSI/ANS 5.1-1979 decay heat model, with a two-sigma uncertainty, instead of the ANS-5 model, with 20%/10% uncertainty. NRC review and approval is requested of these two elements, since they are changes to the current methodology which result in less conservative results.

Main Turbine Pressure Regulation System

The proposal would add a Technical Specification to "3.7 Plant Systems", namely "3.7.8 Main Turbine Pressure Regulation System". The proposed change is required to support the planned Susquehanna Steam Electric Station (SSES) Constant Pressure Power Uprate (CPPU).

In support of the Constant Pressure Power Uprate (CPPU), the SSES transient analyses were reanalyzed. It was determined that an inoperable Main Turbine Pressure Regulation System may result in a reduction in fuel thermal margins. Hence, a new Technical Specification is proposed to require that both main turbine pressure regulators shall be operable.

Prior License Submittals

PUSAR Section 3.2.1, "Reactor Vessel Fracture Toughness," states that a request for amendment to Technical Specification 3.5.10, Reactor Coolant System Pressure – Temperature (P-T) curves has been submitted. In that request, the P-T curves for the reactor coolant system have been revised to account for EPU conditions. PPL submitted the revised P-T curves in PLA 5933 (Reference 2) for the current 40 year licensed life of the units. PPL will provide the technical bases for the P-T curves for the renewed license period at EPU conditions for the planned License Renewal Application.

By letter dated October 13, 2005 (Reference 3), PPL requested a full scope application of an Alternative Source Term (AST) for SSES. The results determined that offsite and control room doses are within regulatory requirements. AST evaluations were performed at CPPU conditions and the results were considered during preparation of the SSES PUSAR. Approval of AST is required prior to NRC approval of CPPU.

PPL has previously requested approval of amendments to the SSES Technical Specifications to permit implementation of Average Power Range Monitor/Rod Block Monitor/Technical Specifications/Maximum Extended Load Line Limit Analysis (ARTS/MELLLA), in Reference 4. ARTS/MELLLA supports operation of SSES in a core flow region, which is above the current rated rod line. Implementation will increase plant efficiency by updating the thermal limits requirements. Approval of ARTS/MELLLA is necessary prior to NRC approval of CPPU for the first approximate 7% increase in Unit 1 and 2 CLTP.

PPL plans to implement the first step of the uprate (approximate 7 % increase) for Unit 2 before restart from the refueling outage currently planned for the Spring 2007. Therefore, to support the PPL schedule for the first power uprate step, and for subsequent reload core design and outage planning, PPL requests that the proposed changes be approved by June 30, 2007.

Implementation of the first step of the uprate is planned to be completed within 120 days from startup (entry into Mode 2) following the Spring refueling outages in 2007 for Unit 2; and 2008 for Unit 1. The remaining portion of the uprate is planned to be implemented within 120 days from startup following the Spring 2009 Refueling Outage for Unit 2; and 2010 for Unit 1.

Two outages for each unit are listed because a stepped approach for increasing power level is planned to obtain optimal fuel utilization and to ensure manageable core thermal limits are maintained. The stepped approach allows a thorough evaluation of plant performance and physical condition following one cycle of CPPU operation. A stepped implementation also results in improved outage management, with respect to modification installation. Also, the modifications necessary for the final 7% step increase may not be installed until the second outage.

Note that a License Amendment Request [PLA-5882, dated October 5, 2005] proposes to delete the Technical Specification requirements related to hydrogen recombiners, containment hydrogen monitors and containment oxygen monitors. The changes are consistent with Revision 1 of the NRC-approved Industry/Technical Specification Task Force (TSTF) Standard Technical Specification Changes Traveler, TSTF-447.

2. PROPOSED CHANGE

The proposed changes all evolve from the fundamental increase in SSES Licensed Thermal Power to 3,952 MWt.

The marked-up pages for the proposed changes to the Operating License and the Technical Specifications (TS) are included in Attachment 1 of this submittal. A PPL proposed license amendment, dated June 27, 2005 (Reference 5), requested approval for a Power Range Neutron Monitor System (PRNMS) upgrade. A PPL proposed license amendment, dated November 18, 2005 (Reference 4), currently in NRC review, requested approval for ARTS/MELLLA implementation. Some of the Technical Specification changes proposed in the PRNMS and ARTS/MELLLA submittals are affected by this EPU submittal. The markups in Attachment 1 show the current Technical Specifications, retyped to include the PRNMS and the proposed ARTS/MELLLA changes, as submitted in Reference 4 and Reference 5.

A PPL proposed license amendment, dated December 1, 2005 (Reference 20), currently in NRC review, requested approval for MCPR Safety Limits and Reference Changes. Some of the Technical Specification changes proposed in the MCPR Safety Limits and Reference submittal are affected by this EPU submittal. The markups in Attachment 1 show the current Technical Specifications, retyped to include the proposed MCPR Safety Limits and Reference Changes as submitted in Reference 20.

This CPPU proposal would change the following:

<u>Extended Power Uprate</u>

PPL is requesting an increase in the maximum authorized power level for Susquehanna from 3489 MWt to 3952 MWt. This represents an increase of approximately 13 percent from the current RTP.

Proposed changes to the Units 1 and 2 Operating License and Technical Specifications are listed in Table 1 with a brief description of the basis for the change.

For clarity, selected TS, including values expressed in percent RTP not affected or changed by this request, are discussed in Table 2. Any value expressed in percent RTP that is not revised for CPPU represents an actual change in absolute Power Level (MWt). The table provides a listing of these values and the bases for not changing them.

As part of the CPPU, PPL is also proposing the following changes to the Licensing Basis:

<u>Standby Liquid Control (SLC) System Technical Specification Change</u>

The proposed change to the SSES Units 1 and 2 SLC Technical Specifications involves the following:

1) Revision of the limit for the minimum concentration of sodium pentaborate in solution from "<13.6 weight-percent but within limits of Figure 3.1.7-1" to "is not within the limits of Figure 3.1.7-1" in Technical Specification 3.1.7, Condition A;

2) Revision of the restoring concentration of sodium pentaborate insolution from "to within limits >13.6 weight percent" to "within limits of Figure 3.1.7-1" in Technical Specification 3.1.7, Required Action A.1,
3) Revision of the completion time from "72 hours AND 10 days from discovery of failure to meet the LCO" to "8 hours" in Technical Specification 3.1.7 Action A,
4) Deleted the completion time condition "AND 10 days from discovery of failure to meet the LCO" in Technical Specification 3.1.7, Action B,
5) Revision of the minimum available volume of tank inventory from "4587 gallons" to "within the limits of Figure 3.1.7-1" in SR 3.1.7.1,
6) Revision of the limit for the minimum concentration of sodium pentaborate in solution from "≥13.6 weight percent and within limits of Figure 3.1.7-1" to "within the limits of Figure 3.1.7-1" in Surveillance Requirement (SR) 3.1.7.5,
7) Revision of the minimum pump flow rate from "41.2 gpm" to "40.0 gpm" in SR 3.1.7.7,
8) Revision of the minimum pump discharge pressure from "1395 psig" to "1250 psig" in SR 3.1.7.7,
9) Replacement of Figure 3.1.7-1 to reflect the lower required sodium pentaborate concentration versus tank volume, which reflects the use of enriched boron; and
10) The addition of a new SR to "Verify the sodium pentaborate enrichment is greater than, or equal to 88 atom percent B-10 prior to adding inventory to the SLC system tank."

The proposed changes are consistent with NUREG-1433 (Reference 6).

<u>LPRM Calibration Interval Technical Specification SR Frequency Change</u>

SR 3.3.1.1.8 currently requires that LPRMs be calibrated at a frequency of every 1000 megawatt-days/metric ton (MWD/MT). The proposed change would revise the frequency of the surveillance to every 2000 megawatt-days/metric ton (MWD/MT).

<u>RHR Service Water System and Ultimate Heat Sink Technical Specification and Methods Change</u>

PPL proposes to modify the RHRSW and UHS Technical Specification 3.7.1 as follows:

Manual UHS Spray Array Bypass Line Isolation Valves – Requirements for the new valves are added to the specification. Associated Conditions and a Surveillance Requirement (SR) are added for these valves. The SR requires verification that the manual UHS spray array bypass line isolation valves can be aligned to the desired position with a frequency of 92 days.

Small Spray Array Isolation Valves – Requirements for the valves are added to the specification. Associated conditions and an SR are added for these valves. The SR requires verification that the small spray array isolation valves can be aligned to the desired position with a frequency of 92 days.

In addition, with respect to decay heat predictions in the UHS performance analysis, PPL proposes the use of ANSI/ANS 5.1-1979 with a two-sigma uncertainty, in lieu of the Branch Technical Position ASB 9-2 model.

Containment Analysis Methods Change

PPL proposes to account for passive heat sinks in the long-term Susquehanna DBA-LOCA containment response analysis, which are not currently credited, as described in Section 6.2.1.1.3.3.1.3 of the SSES FSAR. In addition, with respect to decay heat predictions, PPL proposes the use of ANSI/ANS 5.1-1979 with a two-sigma uncertainty, in lieu of the ANS-5 with 20%/10% uncertainty.

Main Turbine Pressure Regulation System

The proposed new Technical Specification would add: Limiting Conditions for Operation (LCO) requiring either both main turbine pressure regulators be operable or adherence to inoperable regulator limits in the Core Operating Limits Report (COLR); an Applicability statement; Action Statements for a main turbine pressure regulator inoperable; and Surveillance Requirements for the Main Turbine Pressure Regulation System and components.

Technical Specification Bases Changes

PPL proposes to make the supporting changes to the Technical Specification Bases in accordance with Technical Specification 5.5.10, "Technical Specifications (TS) Bases Control Program". Associated Bases changes for Units 1 and 2 are provided in Attachment 2, for information only.

Table 1
Susquehanna Units 1 and 2 Proposed Operating License and Technical Specification Changes

Technical Specification Section	Description of Change	Basis for Change
License Condition C.(1)	Revises the value of the Maximum Power Level to the CPPU power level of 3952 MWt.	See CPPU PUSAR section 1.3.1 and Table 1-2.
1.1, Definitions	Revises the definition of RATED THERMAL POWER (RTP) from 3489 MWt to 3952 MWt.	See CPPU PUSAR section 1.3.1 and Table 1-2.
2.1, Safety Limits, 2.1.1.1, Reactor Core Safety Limits	Revises the Safety Limit (SL) value for Low Pressure or Low Core Flow from 25% RTP to 23% RTP.	See CPPU PUSAR Section 2.1 (This change establishes the threshold for thermal limits monitoring for several other specifications.)
3.1.7, SLC System, Condition A and	Revises the limit for the minimum concentration of sodium pentaborate in solution from "<13.6 weight percent but" to "is not" within the limits of Figure 3.1.7-1.	See CPPU PUSAR 6.5 and 9.3.
3.1.7, SLC System, Required Action A.1	Revises the restoring concentration of sodium pentaborate in solution from ">13.6 weight percent" to "of Figure 3.1.7-1".	See CPPU PUSAR 6.5 and 9.3.
3.1.7, SLC System, Action A Completion Time	Revised "72 hours AND 10 days from discovery of failure to meet the LCO" to "8 hours".	This completion time is consistent Action C. Two SLC subsystems inoperable, since an unacceptable sodium pentaborate concentration would render both subsystems inoperable.
3.1.7, SLC System, Action B Completion Time	Deleted "AND 10 days from discovery of failure to meet the LCO".	The proposed changes to Action A (stated above) eliminate this exception.
3.1.7, SLC System, SR 3.1.7.1	Revises the limit for the minimum volume of sodium pentaborate from "≥4587 gallons" to "within the limits of Figure 3.1.7-1".	See CPPU PUSAR 6.5 and 9.3.
3.1.7, SLC System, SR 3.1.7.5	Deleted "≥13.6 weight percent and" to state that the solution is within the limits of Figure 3.1.7-1.	See CPPU PUSAR 6.5 and 9.3.
3.1.7, SLC System, SR 3.1.7.7	Revises the limit for the pump minimum flow rate from 41.2 gpm to 40.0 gpm and the limit for the pump minimum discharge pressure from 1395 psig to 1238 psig.	See CPPU PUSAR 6.5 and 9.3.

Table 1 Susquehanna Units 1 and 2 Proposed Operating License and Technical Specification Changes		
Technical Specification Section	**Description of Change**	**Basis for Change**
3.1.7, SLC System, New SR 3.1.7.10	Adds a new surveillance requirement to verify the minimum sodium pentaborate enrichment is ≥ 88 atom percent B-10.	See CPPU PUSAR 6.5 and 9.3.
3.1.7, SLC System, Figure 3.1.7-1	Revises the curve providing sodium pentaborate volume versus concentration requirements to provide for the use of enriched sodium pentaborate.	See CPPU PUSAR 6.5 and 9.3.
3.2.1, APLHGR, Applicability	Revises the Applicability from 25% RTP to 23% RTP.	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.
3.2.1, APLHGR, Required Action B.1	Revises the value in the Required Action from 25% RTP to 23% RTP.	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.
3.2.1, APLHGR, SR 3.2.1.1, 1st Frequency	Revises the value in the 1st frequency from 25% RTP to 23% RTP.	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.
3.2.1, APLHGR, SR 3.2.1.1, 3rd frequency	Revises the value in the 3rd frequency from 50% RTP to 44% RTP.	Revises the value for the 3rd SR frequency to maintain the value approximately unchanged in thermal power. At CLTP 50% RTP = 3489 MWt x 0.50 = 1744.5 MWt. At CPPU 1744.5 MWt = 44.14% RTP. The use of 44% RTP is slightly more conservative. At CLTP the SR must be performed within 24 hours after exceeding 1744.5 MWt. At CPPU the SR must be performed within 24 hours after exceeding 1738.8 MWt.
3.2.2, MCPR, Applicability	Revises the Applicability from 25% RTP to 23% RTP.	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.

Table 1
Susquehanna Units 1 and 2 Proposed Operating License and Technical Specification Changes

Technical Specification Section	Description of Change	Basis for Change
3.2.2, MCPR, Required Action B.1	Revises the value in the Required Action from 25% RTP to 23% RTP.	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.
3.2.2, MCPR, SR 3.2.2.1, 1st frequency	Revises the value in the 1st frequency from 25% RTP to 23% RTP.	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.
3.2.2, MCPR, SR 3.2.2.1, 3rd frequency	Revises the value in the 3rd frequency from 50% RTP to 44% RTP.	Revises the value for the 3rd SR frequency to maintain the value approximately unchanged in thermal power. At CLTP 50% RTP = 3489 MWt x 0.50 = 1744.5 MWt. At CPPU 1744.5 MWt = 44.14% RTP. The use of 44% RTP is slightly more conservative. At CLTP the SR must be performed within 24 hours after exceeding 1744.5 MWt. At CPPU the SR must be performed within 24 hours after exceeding 1738.8 MWt.
3.2.3, LHGR, Applicability	Revises the Applicability from 25% RTP to 23% RTP.	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.
3.2.3, LHGR, Required Action B.1	Revises the value in the Required Action from 25% RTP to 23% RTP.	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.
3.2.3 LHGR, SR 3.2.3.1, 1st frequency	Revises the value in the 1st frequency from 25% RTP to 23% RTP.	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.

Table 1
Susquehanna Units 1 and 2 Proposed Operating License and Technical Specification Changes

Technical Specification Section	Description of Change	Basis for Change
3.2.3, LHGR, SR 3.2.3.1, 3rd frequency	Revises the value in the 3rd frequency from 50% RTP to 44% RTP.	Revises the value for the 3rd SR frequency to maintain the value approximately unchanged in thermal power. At CLTP 50% RTP = 3489 MWt x 0.50 = 1744.5 MWt. At CPPU 1744.5 MWt = 44.14% RTP. The use of 44% RTP is slightly more conservative. At CLTP the SR must be performed within 24 hours after exceeding 1744.5 MWt. At CPPU the SR must be performed within 24 hours after exceeding 1738.8 MWt.
3.3.1.1, RPS Instrumentation, Required Action E.1	Revises the value for the Required Action from 30% RTP to 26% RTP	Revises the value for the Required Action to maintain the value approximately unchanged in thermal power. At CLTP, 30% RTP = 1046.7 MWt. At CPPU 1046.7 MWt = 26.49% RTP. The use of 26.0% RTP is slightly more conservative. At CLTP the Required Action requires power be reduced to < 1046.7 MWt. At CPPU the Required Action requires power be reduced to < 1027.5 MWt.
3.3.1.1, RPS Instrumentation, Required Action J.1	Revises the value for the Required Action from 25% RTP to 23% RTP	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.
3.3.1.1, RPS Instrumentation, SR 3.3.1.1.3 and associated Note	Revises the threshold for SR performance to 23% RTP.	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.
3.3.1.1, RPS Instrumentation SR 3.3.1.1.8	Revises the LPRM Calibration Frequency from 1000 MWD/MT to 2000 MWD/MT	See CPPU PUSAR Section 5.1.1.2.

Table 1
Susquehanna Units 1 and 2 Proposed Operating License and Technical Specification Changes

Technical Specification Section	Description of Change	Basis for Change
3.3.1.1, RPS Instrumentation, SR 3.3.1.1.16	Revises the limit specified in the SR from 30% RTP to 26% RTP.	Revises the value for the Limit to maintain the value approximately unchanged in thermal power. At CLTP, 30% RTP = 1046.7 MWt. At CPPU 1046.7 MWt = 26.49% RTP. Use of 26.0% RTP is slightly more conservative. At CLTP the SR verifies that the functions are not bypassed when power is ≥ 1046.7 MWt. At CPPU the SR verifies that the functions are not bypassed when power is ≥ 1027.5 MWt.
3.3.1.1, RPS Instrumentation, SR 3.3.1.1.19	Revises the SR value from 30% RTP to 25% RTP.	See PUSAR Section 2.4.
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, function 2.b	Revises the AV for Simulated Thermal Power – High (for two loop operation) from ≤ 0.62 W + 64.2% RTP to ≤ 0.55 W + 60.7% RTP.	Note this proposed change assumes NRC approval of changes proposed in Reference 4, ARTS/MELLLA. See PUSAR section 5.3.3 and table 5-1. The AV formula for APRM Simulated Thermal Power – High has been recalculated; using an NRC approved methodology based on the change to the Analytical Limit (AL).
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, Note (b)	Revises the AV for Simulated Thermal Power – High (for single loop operation) from ≤ 0.62 (W - ΔW) + 64.2% RTP to 0.55 (W - ΔW) + 60.7% RTP.	Note this proposed change assumes NRC approval of changes proposed in Reference 4, ARTS/MELLLA. See PUSAR section 5.3.3 and table 5-1. Setpoints were determined using an NRC approved methodology based on the change to the Analytical Limit (AL).

Table 1 Susquehanna Units 1 and 2 Proposed Operating License and Technical Specification Changes		
Technical Specification Section	**Description of Change**	**Basis for Change**
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, function 2.f	Revises the Applicability for the OPRM trip function from ≥ 25% RTP to ≥ 23% RTP.	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, function 8	Revises the Applicable Modes or Other Specified Conditions from 30% RTP to 26% RTP.	Revises the threshold value OPERABILITY to maintain the value approximately unchanged in thermal power. At CLTP, 30% RTP = 1046.7 MWt. At CPPU 1046.7 MWt = 26.49% RTP. Use of 26.0% RTP is slightly more conservative. At CLTP the Applicability requires the function to be OPERABLE when power is ≥ 1046.7 MWt. At CPPU the Applicability requires the function to be OPERABLE when power is ≥ 1027.5 MWt.
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, function 9	Revises the Applicable Modes or Other Specified Conditions from 30% RTP to 26% RTP.	Revises the threshold value OPERABILITY to maintain the value approximately unchanged in thermal power. At CLTP, 30% RTP = 1046.7 MWt. At CPPU 1046.7 MWt = 26.49% RTP. Use of 26.0% RTP is slightly more conservative. At CLTP the Applicability requires the function to be OPERABLE when power is ≥ 1046.7 MWt. At CPPU the Applicability requires the function to be OPERABLE when power is ≥ 1027.5 MWt.
3.3.2.2, Feedwater – Main Turbine High Water Level Trip Instrumentation, Applicability	Revises the Applicability from 25% RTP to 23% RTP.	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.

Table 1 Susquehanna Units 1 and 2 Proposed Operating License and Technical Specification Changes		
Technical Specification Section	**Description of Change**	**Basis for Change**
3.3.2.2, Feedwater – Main Turbine High Water Level Trip Instrumentation, Required Action C.1	Revises the value for the Required Action from 25% RTP to 23% RTP	Revised to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1.
3.3.4.1, EOC-RPT Instrumentation, Applicability	Revises the Applicability from 30% RTP to 26% RTP.	Revises the Applicability to maintain the value approximately unchanged in thermal power. At CLTP, 30% RTP = 1046.7 MWt. At CPPU 1046.7 MWt = 26.49% RTP. Use of 26.0% RTP is slightly more conservative. At CLTP the Applicability requires the function to be OPERABLE when power is ≥ 1046.7 MWt. At CPPU the Applicability requires the function to be OPERABLE when power is ≥ 1027.5 MWt.
3.3.4.1, EOC-RPT Instrumentation, Required Action C.2	Revises the value of 30% RTP to 26% RTP	Revises the value to maintain it approximately unchanged in thermal power. At CLTP, 30% RTP = 1046.7 MWt. At CPPU 1046.7 MWt = 26.49% RTP. Use of 26.0% RTP is slightly more conservative. At CLTP the Required Action requires power to be reduced to ≤ 1046.7 MWt. At CPPU the Applicability requires the function to be OPERABLE when power is ≤ 1027.5 MWt.

Table 1 Susquehanna Units 1 and 2 Proposed Operating License and Technical Specification Changes		
Technical Specification Section	**Description of Change**	**Basis for Change**
3.3.4.1, EOC-RPT Instrumentation, SR 3.3.4.1.4	Revises the value of 30% RTP to 26% RTP	Revises the value to maintain it approximately unchanged in thermal power. At CLTP, 30% RTP = 1046.7 MWt. At CPPU 1046.7 MWt = 26.49% RTP. Use of 26.0% RTP is slightly more conservative. At CLTP the SR requires verification the function is not bypassed when power is ≥ 1046.7 MWt. At CLTP the SR requires verification the function is not bypassed when power is ≥ 1027.5 MWt.

Table 1
Susquehanna Units 1 and 2 Proposed Operating License and Technical Specification Changes

Technical Specification Section	Description of Change	Basis for Change
3.3.6.1, Primary Containment Isolation Instrumentation, function 1.c, Main Steam Line Flow High	Revises the AV from 121 psid to 179 psid.	See CPPU PUSAR 5.3.1. The current AV of 121 psid corresponds to an analytical limit (AL) of 138% of the CLTP rated steam flow. The value of 138% resulted from an increase in rated steam flow resulting from a reduction in measurement uncertainty associated with use of the leading edge flow meter technology for measuring FW flow rate. Prior to that change the AL in % steam flow was 140%. For CPPU the AL in % steam flow is restored to its prior value of 140%. To accommodate the increased steam flow for CPPU, the flow instrumentation is being replaced with instrumentation capable of monitoring the increased main steam flow rate. The AV and associated nominal trip setpoint (NTSP) were recalculated using an NRC approved methodology considering the (1) increase in AL to restore the previous AL of 140%, (2) the increased CPPU steam flow and (3) the replacement main steam line isolation instrumentation.
3.4.2, Jet Pumps, SR 3.4.2.1, Note 2	Revises the value of 25% RTP to 23% RTP.	Revises the note to incorporate the reduction in thermal limits monitoring threshold required by the change to TS 2.1.1.1.
3.4.3, Safety/Relief Valves (S/RVs), LCO	Revises the LCO to require 14 S/RVs to be OPERABLE versus 12 S/RVs	See CPPU PUSAR Section 3.1.

Table 1 Susquehanna Units 1 and 2 Proposed Operating License and Technical Specification Changes		
Technical Specification Section	**Description of Change**	**Basis for Change**
3.4.10, RCS P/T Limits, SR 3.4.10.5, Note a	Revises the value of 30% RTP to 27% RTP	Revises the value to maintain it approximately unchanged in thermal power. At CLTP, 30% RTP = 1046.7 MWt. At CPPU 1046.7 MWt = 26.49% RTP. Use of 27.0% RTP is slightly more conservative. At CLTP the SR must be met when power is ≤ 1046.7 MWt. At CLTP the SR must be met when power is ≤ 1067.0 MWt.
3.4.10, RCS P/T Limits, SR 3.4.10.6, Note a	Revises the value of 30% RTP to 27% RTP	Revises the value to maintain it approximately unchanged in thermal power. At CLTP, 30% RTP = 1046.7 MWt. At CPPU 1046.7 MWt = 26.49% RTP. Use of 27.0% RTP is slightly more conservative. At CLTP the SR must be met when power is ≤ 1046.7 MWt. At CLTP the SR must be met when power is ≤ 1067.0 MWt.
3.6.1.3, PCIVs, SR 3.6.3.12	Revise the 1st test pressure from 22.5 psig to 24.3 psig.	See CPPU PUSAR section 4.1.1 and Table 4-1. This value is maintained at 0.5 x P_a.
3.7.1, RHRSW and UHS, Condition A	Adds the entry conditions for inoperable valves in a new Table 3.7.1-3 and the entry conditions for the combination of valves inoperable in Tables 3.7.1-1, 3.7.1-2, and 3.7.1-3 that are in the same return header.	Revised to add valves whose operation is credited in the UHS performance analysis. See CPPU PUSAR 6.4.5.
3.7.1, RHRSW and UHS, SR 3.7.1.6	Adds the SR to periodically stroke the small loop spray array valves with a frequency of 92 days.	Surveillance is added for valves whose operation is credited in the UHS performance analysis. See CPPU PUSAR 6.4.5.

Table 1 Susquehanna Units 1 and 2 Proposed Operating License and Technical Specification Changes		
Technical Specification Section	**Description of Change**	**Basis for Change**
3.7.1, RHRSW and UHS, SR 3.7.1.7	Adds the SR to periodically stroke the spray loop bypass manual valves with a frequency of 92 days.	Surveillance is added for valves whose operation is credited in the UHS performance analysis. See CPPU PUSAR 6.4.5.
3.7.1, RHRSW and UHS, Table 3.7.1-1	Adds the spray loop small spray array valves to the Table 3.7.1-1	Revised to add valves whose operation is credited in the UHS performance analysis. See CPPU PUSAR 6.4.5.
3.7.1, RHRSW and UHS, Table 3.7.1-3	Adds a new Table 3.7.1-3 for the spray array bypass manual valves	Revised to add valves whose operation is credited in the UHS performance analysis. See CPPU PUSAR 6.4.5.
3.7.6, Main Turbine Bypass System, Applicability	Revises the value of 25% RTP to 23% RTP.	Revises the Applicability to incorporate the reduction in thermal limits monitoring threshold required by the change to TS 2.1.1.1.
3.7.8, Main Turbine Pressure Regulation System	Adds a new technical specification requiring either both main turbine pressure regulator be operable or adherence to inoperable regulator limits in the Core Operating Limits Report (COLR)	At CPPU conditions failure of a pressure regulator with the redundant pressure regulator out of service, is a limiting event. The new specification requires either prompt restoration of the inoperable pressure regulator to OPERABLE status or requires appropriate thermal limits specified in the COLR for the condition be applied to ensure that Safety Limits are not exceeded.
5.5.12, Primary Containment Leakage Rate Testing Program	Revises the value of P_a from 45.0 psig to 48.6 psig.	See CPPU PUSAR section 4.1.1 and Table 4-1.

Table 1 Susquehanna Units 1 and 2 Proposed Operating License and Technical Specification Changes		
Technical Specification Section	**Description of Change**	**Basis for Change**
5.6.5.b, Core Operating Limits Report (COLR)	Removes the restriction on THERMAL POWER level when feedwater flow measurements from the Leading Edge Flow Meter System are not available.	Use of the Leading Edge Flow Meter System permitted a reduction in the uncertainty associated with analytical limits used to determine the core operating limits from 2% RTP to 0.4% RTP and allowed operating at a higher thermal power level. TS 5.6.5.b restricts THERMAL POWER to a reduced power level when the Leading Edge Flow Meter System is not available such that a 2% margin between the operating power level and the power level used in the analyses is maintained. For CPPU the analytical methods used to determine the core operating limits utilizes 2% uncertainty without regard for the improved feedwater flow measurement accuracy provided by the Leading Edge Flow Measurement System. Consequently, the restriction on THERMAL POWER level when feedwater flow measurements from the Leading Edge Flow Meter System are not available is no longer appropriate.
5.6.5.b, Core Operating Limits Report (COLR), Listing of approved analytical methods, item 10 and 11	Delete approved analytical methods 10 and 11 (for Unit 1) and methods 17 and 18 (for Unit 2). Renumber subsequent methods 12, 13, 14, and 15 (for Unit 1) and method 19 (for Unit 2) accordingly.	The methods being deleted are no longer needed with the restoration of the 2% margin between the analyses and the operating power level. See change to 5.6.5.b above.

Table 2
Susquehanna Units 1 and 2 Technical Specifications Unchanged References to % RTP

Technical Specification Section	Bases for No Change
1.3, Completion Times	Example 1.3-5, contain "% RTP," this is only an example used to clarify Completion Time requirements and does not need to change for CPPU.
1.4, Frequency	Examples 1.4-1, 1.4-2 and 1.4-3 contain "% RTP," these are only examples used to clarify frequency requirements and do not need to change for CPPU.
3.1.3, Control Rod OPERABILITY, Note to Condition D and Note to Condition E.	Maintaining the value at 10% RTP is more conservative in terms of absolute Power. At CLTP the allowance provided by this note is applicable > 348.9 MWt. At CPPU the allowance provided by this note is applicable > 395.2 MWt.
3.1.4, Control Rod Scram Times, SR 3.1.4.1 1st and 2nd Frequency and SR 3.1.4.4 Frequency	The 40% RTP used in the surveillance requirement is a value chosen for convenience and is not a critical parameter. The 40% RTP remains unchanged even though the actual power level will be slightly higher than the pre-CPPU condition. 40% RTP is greater than the Rod Worth Minimizer low power set point (≤ 10% RTP) such that Control Rod Drive positioning is less restricted and scram testing is easier to perform. Reactor dome pressure is expected to be greater than 800 psig, which allows testing conditions that are closer to normal operating pressure. Additionally 40% RTP is well below 100% RTP.
3.1.6, Rod Pattern Control, Applicability	Maintaining the value at 10% RTP is more conservative in terms of absolute Power. At CLTP this specification is applicable in Modes 1 and 2 when power is ≤ 348.9 MWt. At CLTP this specification is applicable in Modes 1 and 2 when power is ≤ 395.2 MWt..
3.3.1.1, RPS Instrumentation, SR 3.3.1.1.2	The ≤ 2% RTP permissible deviation between average power range monitor channels and calculated power is a tolerance value and does not need to change for CPPU.
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, function 2.a Allowable Value	The allowable value (AV) for this function is not changed. The associated design limit was reduced by 2% RTP to incorporate the reduction in thermal limits monitoring threshold required by the changes to TS 2.1.1.1. A setpoint calculation was performed using an NRC approved methodology. The setpoint calculation determined the AV does not change. This is due to the improved accuracy of the PRNMS system and apparent conservatism in establishing the existing AV.
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, Functions 2b Simulated Thermal Power - High (clamp value) and Function 2c, Fixed Neutron Flux - High	The allowable values of 115.5% RTP for function 2b and 120%RTP for function 2c are not changed to maintain the same nominal trip setpoint and the analytical limit values.

Table 2 Susquehanna Units 1 and 2 Technical Specifications Unchanged References to % RTP	
Technical Specification Section	**Bases for No Change**
3.3.2.1, Control Rod Block Instrumentation, Note for SR 3.3.2.1.2, and Note for SR 3.3.2.1.3, and SR 3.3.2.1.5	Maintaining the value at ≤ 10% RTP is more conservative in terms of absolute Power. At CLTP the SR must be performed after power is ≤ 348.9 MWt. At CPPU the SR must be performed after power is ≤ MWt 395.2 MWt.
3.3.2.1, Control Rod Block Instrumentation, SR 3.3.2.1.5	Maintaining the value at 10% RTP is conservative in terms of absolute power. At CLTP the SR verifies the RWM is not bypassed when ≤ 348.9 MWt. At CPPU the SR verifies the RWM is not bypassed when ≤ 395.2 MWt.
3.3.2.1, Control Rod Block Instrumentation, SR 3.3.2.1.4.a; Table 3.3.2.1-1, Notes to Applicable Mode or Other Specified Conditions (a), (c), (d), and (e)	The low power setpoint (LPSP), intermediate power setpoint (IPSP), and high power setpoint (HPSP) for the Rod Block Monitor do not change for CPPU. Setpoints are verified on a cycle specific basis.
3.3.2.1, Control Rod Block Instrumentation, Table 3.3.2.1-1, Note (g)	Maintaining the value at ≤ 10% RTP is more conservative in terms of absolute Power. At CLTP the function is applicable when power is ≤ 348.9 MWt. At CPPU the function is applicable when power is ≤ 395.2 MWt.
3.5.1, ECCS-Operating, SR 3.5.1.6, Frequency	The value of 25% RTP used in the surveillance requirement is a value chosen for convenience and is not a critical parameter. The 25% RTP remains unchanged even though the actual power level will be slightly higher than the pre-CPPU condition.
3.6.3.3, Primary Containment Oxygen Concentration, Applicability (a and b) and Required Action B	The 15% RTP establishes start of a 24 hour window for completing inerting and de-inerting the containment during plant startups and shutdowns. The sequence of operations during plant startups and shutdowns is substantially unchanged by the EPU. Therefore, the current 15% RTP value does not need to be changed.

3. BACKGROUND

Extended Power Uprate

The Susquehanna Steam Electric Station (SSES) was originally licensed to operate at a maximum power level of 3293 MWt.

PPL has performed 2 power uprates. The first uprate, termed a Stretch Uprate, increased the licensed thermal power by approximately 4.5% (References 7, 8, and 9). The second uprate of 1.4% was a result of improved instrumentation allowing a reduction in the uncertainty in thermal power, termed an Appendix K Uprate or Measurement Uncertainty Recapture (MUR) (Reference 10).

An increase in the electrical output of a BWR plant is accomplished primarily by generating and supplying higher steam flow to the turbine-generator. As currently licensed, most BWR plants, including SSES, have an as-designed equipment and system capability to accommodate steam flow rates above the original rating. In addition, continuing improvements in the analytical techniques (computer codes and data) based on several decades of BWR safety technology, plant performance feedback, and improved fuel and core designs have resulted in a significant increase in the design and operating margins between calculated safety analysis results and the licensing limits. These available safety analyses differences, combined with the excess as-designed equipment, system and component capabilities, provide BWR plants the capability to achieve an increase in their thermal power ratings of between 5 and 20% without major nuclear steam supply system (NSSS) hardware modifications.

In March 2003, the NRC approved the use of the CLTR as a basis for power uprate license amendment requests, subject to limitations specified in the CLTR and in the associated NRC safety evaluation. The limitations relate to license amendment requests that may not be pursued concurrently with the power uprate request. In addition, licensees proposing to use fuel designs other than GE fuel may reference the CPPU LTR as a basis for their power uprate for areas other than those involving reactor systems and for fuel issues which are not impacted by the fuel design.

A higher steam flow is achieved by increasing the reactor power along specified control rod and core flow lines. A limited number of operating parameters are changed, some setpoints are adjusted and instruments are recalibrated. Plant procedures are revised, and tests similar to some of the original startup tests are performed. Modifications to some power generation equipment will be implemented over time, as needed.

Detailed evaluations of the reactor, engineered safety features, power conversion, emergency power, support systems, environmental issues, and design basis accidents were performed. These evaluations demonstrate that SSES can safely operate at 3952 MWt.

Standby Liquid Control (SLC) System Technical Specification Change

The SLC system is discussed in Section 9.3.5 of the SSES Final Safety Analysis Report (FSAR). The system is designed to bring the reactor, at any time during the fuel cycle, from full power to a sub-critical condition, without taking any credit for control rod motion following a scram. The SLC system complies with the requirements of 10 CFR 50.62, "Requirements for reduction of risk from anticipated transients without scram (ATWS) events for light-water-cooled nuclear power plants."

An analysis was used to determine the required boron weight-percent, concentration, and enrichment, as well as the minimum pump flow rate required to safely shutdown the reactor. Consistent with the requirements of 10 CFR 50.62, the analysis assumed no control rod movement, and failure of the Alternate Rod Insertion (ARI) system following a scram, and demonstrated that the ATWS acceptance criteria for critical plant parameters are satisfied.

The results of that analysis concluded that the requirements of 10 CFR 50.62 are satisfied with the following SLC system attributes:

1) A sodium pentaborate solution with a weight-percent greater than or equal to 7.0% (versus the current 13.6%);
2) A sodium pentaborate solution with an enrichment equal to or greater than 88 atom percent B-10;
3) A reactor shutdown boron requirement of 660 ppm, plus a 25% margin for leakage and imperfect mixing;
4) A total system flow rate of 40.0 gal/min (versus. the current 82.4 gal/min).

PPL intends to replace the existing sodium pentaborate solution with a solution as described by items 1 thru 3. In addition, to improve the overall reliability of the SLC system, the system control logic will be modified to provide for single pump versus two pumps operation. With single pump operation, the use of the proposed enriched boron solution is required to support operation at CPPU conditions.

Precedent submittals for the use of an enriched sodium pentaborate solution are the Duane Arnold Energy Center, Fermi-2, Brown Ferry, and Hatch plants. The Brunswick approved license change (Reference 11) is specifically cited since it is a recent precedent similar to this request, and was in support of a BWR Extended Power Uprate.

In a separate license amendment request (Reference 3), PPL has proposed the implementation of an Alternative Source Term (AST), which complies with the guidance given in RG 1.183 and US NRC Standard Review Plan Section 15.01. Under the provisions of that request, the SLC system will be used to maintain suppression pool pH level above 7 following any DBA-LOCAs, which could involve significant fission product releases.

The use of the proposed enriched boron solution is required to support the implementation of CPPU at SSES.

LPRM Calibration Interval Technical Specification SR Frequency Change

Each LPRM detector contains a fission chamber. When neutrons interact with fissile material within the fission chamber, a signal is generated and conditioned, indicating neutron flux intensity, which is related to local power. Each LPRM assembly also contains a calibration tube for a Traversing Incore Probe (TIP). The TIP system is used to calibrate the LPRMs to maintain design accuracy during operations. The TIP system provides a signal proportional to the neutron flux and this high precision signal is used for adjusting LPRM gains during calibration.

LPRMs are calibrated periodically because of changes in the instrument sensitivity due to depletion of the fissile detection material. Calibration data is obtained from the TIP system, using the movable neutron detectors to measure the in-core flux distribution for comparison with the LPRM readings.

At CPPU Rated Thermal Power (RTP), 1000 MWD/MT is about 34 days (i.e., 1000 MWD/MT x 136 metric tons ÷ 3952 MWt). The proposed change to the SR frequency will approximately double the effective time interval between successive LPRM calibrations.

RHR Service Water System and Ultimate Heat Sink Technical Specification and Methods Change

The UHS is an 8-acre, 25 million gallon concrete lined spray pond. The function of the UHS is to provide water to the RHRSW and ESW systems at a temperature less than the 97°F design temperature of the RHRSW and ESW systems. The UHS is designed to supply the RHRSW and ESW systems with the cooling capacity required following a design bases LOCA in one unit and concurrent safe shutdown of the other unit for thirty days without fluid addition. The UHS spray system consists of 2 divisions, each with a large and small spray array and a spray array bypass line. The UHS is described in the FSAR, Section 9.2.7.

As a result of operation at CPPU conditions, the post-LOCA UHS heat load increases, primarily due to higher reactor decay heat. A review was performed to evaluate the increased UHS heat load for the CPPU. This review concludes that the UHS system, modified as noted in Section 1, Description, above and Attachment 4, Section 6.4.5, is capable of maintaining a maximum design temperature of 97°F following a design basis LOCA in one unit and concurrent safe shutdown of the other unit. The revised analysis used decay heat values calculated per the ANSI/ANS 5.1-1979 decay heat model, with a two-sigma uncertainty, instead of the Branch Technical Position ASB 9-2 model, which is the current licensing basis.

Containment Analysis Methods Change

The DBA-LOCA long-term containment response is described in Section 6.2.1.1.3.3.1.3 of the FSAR. The supporting analysis, which was performed for the Stretch Uprate in the early 1990's, was performed with the GE SHEX methodology. In that analysis, passive heat sinks were not credited, and the ANS-5, with 20%/10% uncertainty decay heat model, was used as input.

The CPPU re-evaluation of the DBA-LOCA for the long term suppression pool temperature response was performed by General Electric with the SHEX computer program, which is the SSES Current Licensing Basis methodology. To provide for consistency with current GE standards for containment re-evaluations, two alternate analytical elements, which are not part of the SSES current containment analytical bases, were employed. These elements are: 1) crediting the presence of passive heat sinks; and, 2) the use of the ANSI/ANS 5.1-1979 decay heat model, with a two-sigma uncertainty, instead of the ANS-5 model, with 20%/10% uncertainty.

Main Turbine Pressure Regulation System

The Main Turbine Pressure Regulation System is designed to control main steam pressure. The Main Turbine Pressure Regulation System contains two pressure regulators which are provided to maintain primary system pressure control. Failure of the primary or controlling pressure regulator and the backup pressure regulator are discussed in FSAR Section 15.2.1. The main turbine pressure regulation function of the Turbine Electro Hydraulic Control System is discussed in the FSAR, Sections 7.7.1.5 and 15.2.1.

If the backup pressure regulator fails downscale or is out of service when the primary regulator fails downscale, the turbine control valves (TCVs) will close in the servo or normal operating mode. Since the TCV closure is not a fast closure, there is no loss of EHC pressure to provide an anticipatory scram. The reactor pressure will increase to the point that a high neutron flux or a high reactor pressure scram is initiated to shut down the reactor. An inoperable Main Turbine Pressure Regulation System may result in a MCPR and / or LHGR penalty.

Hence, a new Technical Specification is proposed with an LCO requiring Both Main Turbine Pressure Regulators be operable to limit the pressure increase in the main steam lines and reactor pressure vessel during a postulated failure of the controlling pressure regulator so that the Safety Limit MCPR and LHGR are not exceeded.

4. TECHNICAL ANALYSIS

Extended Power Uprate

The safety analysis report in Attachment 4 summarizes the results of the significant safety evaluations performed that justify uprating the licensed thermal power at Susquehanna Steam Electric Station (SSES).

Summary

The generation and supply of higher steam flow for the turbine-generator accomplishes an increase in electrical output of a BWR plant. Most BWR plants, including SSES, as currently licensed, have an as-designed equipment and system capability to accommodate steam flow rates at least 5% above the original rating. In addition, continuing improvements in the analytical techniques (computer codes and data) based on several decades of BWR safety technology, plant performance feedback, and improved fuel and core designs have resulted in a significant increase in the design and operating margins between calculated safety analysis results and the licensing limits. These available safety analyses differences, combined with the excess as-designed equipment, system and component capabilities, provide BWR plants the capability to achieve an increase in their thermal power ratings of between 5 and 20% without major nuclear steam supply system (NSSS) hardware modifications, and to provide for power increases to 20% with limited hardware modifications, with no significant increase in the hazards presented by the plant as approved by the NRC at the original license stage.

The plan for achieving higher power is to extend the power to flow map along the standard Maximum Extended Load Line Limit Analysis (MELLLA) power to flow upper boundary. The extension of the power-to-flow map does not require an increase in the maximum core flow limit or operating pressure over the pre-CPPU values.

Discussions of Issues Being Evaluated

SSES performance and responses to postulated accidents and transients have been evaluated for a CPPU license amendment. The safety assessment summarizes the safety significant plant responses to events analyzed, consistent with the current licensing basis, and the effects on various margins of safety. The results determined that no significant hazards consideration is involved.

CPPU Analysis Basis

SSES has performed two power uprates. The first uprate, termed a Stretch Uprate, increased the licensed thermal power by approximately 4.5%. (References 7, 8, and 9) The second uprate of 1.4% was a result of improved instrumentation allowing a reduction in the uncertainty in thermal power, termed an Appendix K Uprate or Measurement Uncertainty Recapture (MUR) (Reference 10). The key thermal power levels are as follows:

- The Original Licensed Thermal Power (OLTP) is 3293 MWt.
- The Stretch Uprate Licensed Thermal Power is 3441 MWt.
- The Current Licensed Thermal Power (CLTP) and Rated Thermal Power (RTP) is the Appendix K Uprate Power, which is 3489 MWt.
- The Analysis Thermal Power is 1.02 x 3441 MWt or 3510 MWt.

Note that the Appendix K Uprate reduced the power uncertainty to 1.006, therefore the analysis power level remains the same, namely 1.006 x 3489 MWt = 3510 MWt.

Thus, SSES is currently licensed for operation up to 3489 MWt, and the current safety analyses are based on this value. The CPPU RTP level included in this evaluation is 120% of the original licensed thermal power level. The CPPU safety analyses are based on a power level of 1.02 times the CPPU power level unless the Regulatory Guide 1.49 two percent power factor is already accounted for in the analysis methods.

Fuel Thermal Limits

No new fuel design is required for CPPU. The current fuel design limits will continue to be met at CPPU conditions. Analyses for each fuel reload will continue to meet the criteria accepted by the NRC. Future fuel designs will meet acceptance criteria accepted by the NRC.

Makeup Water Sources

The BWR design concept includes a variety of ways to pump water into the reactor vessel to mitigate all types of events. There are numerous safety-related and non-safety-related cooling sources. The safety-related cooling water sources alone would maintain core integrity by providing adequate cooling water.

CPPU does not result in a change in the number of available water sources, nor does it change the selection of those assumed to function in the safety analyses. NRC-approved methods were used for analyzing the performance of the Emergency Core Cooling Systems (ECCS) during loss-of-coolant-accidents.

CPPU results in an increase in decay heat, and thus, the time required to cooldown to cold shutdown conditions increases. The existing cooling capacity can bring the SSES units to cold shutdown within a time span that continues to meet plant safety and regulatory operational requirements.

Design Basis Accidents

Design Basis Accidents (DBAs) are very low probability postulated events whose characteristics and consequences are used in the design of the plant, so that the plant can mitigate their consequences to within acceptable regulatory limits. For BWR licensing evaluations, capability is demonstrated for coping with the range of postulated pipe break sizes in the largest recirculation, steam, and feedwater lines, a postulated break in one of the ECCS lines, and the most limiting small lines. This break range bounds the full spectrum of large and small, high and low energy line breaks; and ensures the success of plant systems to mitigate the accidents, while accommodating a single active equipment failure in addition to the postulated LOCA. Several of the most significant licensing assessments are made using these LOCA ground rules. These assessments are:

1. **Challenges to Fuel**

Emergency Core Cooling Systems (ECCS) are described in Section 6.2 of the SSES Final Safety Analysis Report (FSAR). The ECCS Performance Evaluation described in Attachment 4, Section 4.3 demonstrates the continued conformance to the acceptance criteria of 10 CFR 50.46. A complete spectrum of pipe breaks is investigated from the largest recirculation line down to the most limiting small line break. As shown in Attachment 4, Table 4-2, the licensing safety margin is not affected by CPPU. The change in peak clad temperature (PCT) for CPPU is insignificant compared to the large amount by which the results are below the regulatory criteria. Therefore, the ECCS safety margin is not affected by CPPU.

2. **Challenges to the Containment**

Attachment 4, Table 4-1 provides the results of analyses of the SSES containment response to the most severe LOCAs. The effect of CPPU on the peak values for containment pressure and temperature confirms the suitability of the plant for operations at CPPU RTP. Also, the effects of CPPU on the conditions that affect the containment dynamic loads are evaluated, and the results were satisfactory for CPPU operation. Where plant conditions with CPPU are within the range of conditions used to define the current dynamic loads, current safety criteria are met and no further structural analysis is required. The change in short-term containment response is acceptable. Because there will be more residual heat with CPPU, the containment long-term response increases. However, containment pressures and temperatures remain below their design limits following any design basis accident, and thus, the results for the containment and its cooling systems are satisfactory for CPPU operation. The increase in the calculated post LOCA suppression pool temperature above the currently assumed peak temperature was evaluated and determined to be acceptable, since it remains below the limit.

The NPSH requirements for the Residual Heat Removal and Core Spray pumps were analyzed at the maximum pump runout flows, which exceed the pump design basis flows, a temperature of 220° F, which is the suppression pool design limit, and the maximum design basis suction strainer debris loading. The analysis assumes the containment pressure is equal to the vapor pressure of the suppression pool water to ensure that no credit is taken for containment overpressure during design basis accidents. The inputs in the ECCS NPSH calculations for friction loss, static head, and suction strainer debris loading are not changed and are not affected by EPU. Therefore, the available NPSH exceeds the required NPSH for the RHR and CS pumps.

3. Design Basis Accidents Radiological Consequences

An analysis of the impact of operation at CPPU conditions on the radiological consequences of DBAs was performed in a separate license amendment request (Reference 3) proposing a full scope implementation of an Alternative Source Term (AST) as promulgated in 10 CFR 50.67. The proposed SSES CPPU radiological source term was used as the basis for the AST license amendment request. The AST analyses were performed using guidance in Regulatory Guide 1.183 and Standard Review Plan Section 15.0.1. Offsite and control room doses were determined for the following major DBAs: Loss of Coolant Accident Inside Containment, Main Steam Line Break Outside Containment, Fuel and Equipment Handing Accidents, and Control Rod Drop Accident.

The dose consequence analyses demonstrate that the dose criteria of 10 CFR 50.67 are met for the CPPU power level. The dose consequence evaluations include related CPPU modifications and use of recent meteorological dispersion data.

Other plant specific radiological analyses in the SSES design basis were reviewed and updated for CPPU conditions. The dose consequences for these postulated radiological accidents remain within applicable regulatory limits.

Anticipated Operational Occurrence Analyses

The effects of Anticipated Operational Occurrences (AOO) are evaluated by investigating a number of disturbances of process variables and malfunctions or failures of equipment. These events are primarily evaluated against the Safety Limit Minimum Critical Power Ratio (SLMCPR) and other applicable Specified Acceptable Fuel Design Limits (SAFDLs) such as the avoidance of fuel centerline melting and not exceeding 1% fuel cladding plastic strain. Compliance with SLMCPR and with the other applicable SAFDLs has been determined using NRC-approved methods. As described in Section 9.1 of Attachment 4, the limiting AOOs have been evaluated for the CPPU RTP conditions. No change to the basic characteristic of any of the limiting events is caused by the CPPU. The results of the CPPU AOO evaluations demonstrate that CPPU RTP operation can be safely implemented consistent with the bases for the Technical Specification Power Distribution Limits. Licensing acceptance criteria are not exceeded. Continued compliance with the SLMCPR and other applicable Specified Acceptable Fuel Design Limits will be confirmed on a cycle specific basis. Therefore, the margin of safety is not affected by CPPU.

The current licensing basis (FSAR Section 10.4.7) indicates that either a single feedwater pump trip or a single condensate pump will not result in a reactor SCRAM. As a result of CPPU, under certain atmospheric conditions (high ambient temperatures) and certain reactor flow (high rod lines) i.e., during very limited periods of time, the ability to avoid a SCRAM upon a single feedwater pump trip or a single condensate pump trip may not be assured. Section 7.4.2, "Transient Operation" of the PUSAR (Attachment 4) provides a description of the feedwater system evaluation.

Combined Effects

Design basis accidents are postulated using deterministic regulatory criteria to evaluate challenges to the fuel, containment, and site related accident radiation dose limits. The off-site and control room dose evaluations are performed in accordance with Regulatory Guide 1.183, the AST methodology. The postulated DBAs are not intended to represent actual event sequences but are intended to serve as surrogates to enable the performance of deterministic evaluations of the response of the plant's engineered safety features. These evaluations are selected to produce the greatest challenge to fuel and containment and bound the effects of other DBAs.

The DBA that produces the highest peak clad temperature does not result in more severe damage to the fuel than assumed in the SSES off-site and control room dose evaluations. The DBA that produces the maximum containment pressure does not result in leak rates to the environment that are greater than assumed used in the off-site and control room dose evaluations. Thus, the post accident doses calculated in conformance with Regulatory Guide 1.183 and SRP Section 15.0.1 provide bounding DBA results that envelope the greatest challenge to fuel and containment.

Environmental Qualification

Safety related electrical equipment and instrumentation have been evaluated under normal and accident environmental conditions associated with operation at CPPU conditions. The qualification envelope does not change significantly due to CPPU. Equipment evaluations determined that the majority of equipment remains qualified for operation at CPPU conditions. Components that do not meet initial qualification based on CPPU conditions will be qualified using additional analysis or replaced with qualified replacements prior to increasing power above CLTP conditions.

Balance-of-Plant

The balance-of-plant (BOP) systems and equipment used to perform safety-related and normal operation functions have been reviewed for CPPU in a manner comparable to that for safety-related NSSS systems/equipment. CPPU operation for BOP systems and equipment is supported by either generic or plant specific evaluations, which includes modifications made (or planned) to BOP components.

Core Thermal Power Measurement

The current licensed thermal power level (3489MWt) is based on reduced uncertainty in core thermal power measurement achieved with the leading edge flow meter or (LEFM✓™) ultrasonic flow measurement system described in Reference 10. If the LEFM✓™ system becomes unavailable, plant operation at 3489MWt may continue for 6 hours after the last valid correction factor was obtained from the LEFM✓™ system. Procedural guidance directs that reactor power be reduced to a level less than or equal to the previously licensed power level (3441MWt) if the LEFM✓™ system cannot be restored to operation within 6 hours. Core power is then maintained at a level less than or equal to 3441 MWt until the LEFM✓™ system is returned to service.

Analyses for the proposed CPPU are based on a power level at least 1.02 times the CPPU power level unless the Regulatory Guide 1.49 two percent power factor is already accounted for in the analysis methods. Therefore, following NRC approval of the proposed amendment Technical Specifications and plant procedures will no longer direct that power be reduced if the measurement system becomes unavailable.

Probabilistic Risk Assessment

Attachment 4, Section 10.5 describes the results of Level 1 and Level 2 Probabilistic Risk Assessments (PRAs) performed for CPPU conditions. Using the NRC guidelines established in Regulatory Guide 1.174 and the calculated results from the Level 1 PRA, the best estimate for the SSES CDF risk increase due to the CPPU (1.1E-07/yr for both units) is in the lower left corner of Region III (i.e., very small risk changes). The best estimate for the LERF increase (1.0E-09/yr for both units) is also in the lower left corner of the Region III range of RG 1.174.

Primary Containment Leakage Rate Testing Program

Surveillance Requirements 3.6.1.1.1, 3.6.1.2.1, 3.6.1.3.11, 3.6.1.3.12, and 3.6.1.3.13 require that primary containment leakage rates be demonstrated in accordance with the Primary Containment Leakage Rate Testing Program. The testing program is required by 10 CFR 50.54(o) and 10 CFR 50 Appendix J and is described in Technical Specification 5.5.12. The program is established on a performance basis in accordance with 10 CFR 50 Appendix J, Option B, as modified by approved exemptions.

The Type A integrated leak rate test and the Type B and C local leak rate tests are performed at the calculated peak containment pressure (Pa). Pa increases to 48.6 psig for the CPPU; and Technical Specifications 3.6.1.3.12 and 5.5.12 are being revised to reflect the change.

Standby Liquid Control (SLC) System Technical Specification Change

The evaluation of the SLC system performance for ATWS plant transient conditions was performed in accordance with NEDC-32424P-A (Reference 12) and NEDC-33004P-A (Reference 1). These evaluations are described in Attachment 4, Sections 6.5 (9.3.1, and 9.3.3). The key results of these evaluations are discussed below.

Based upon SLC shutdown margin analyses, the existing natural boron concentration requirements for achieving cold shutdown (660 PPM natural boron) is not increased for CPPU. The allowable concentrations (in weight-percent) of the SLC tank sodium pentaborate solution are being lowered, as shown on the attached Technical Specification mark-ups (Attachment 1). This is intended to limit the reliance on tank and piping heat tracing, thus providing for additional assurance of system Operability. The revised tank volume and concentrations are based on achieving the reactor shutdown boron requirement of 650 ppm, plus a 25% margin for leakage and imperfect mixing.

As discussed Section 9.3.3 of Attachment 4, SLC system operation, assuming single pump operation, with a sodium pentaborate solution with properties within the acceptance region of the new proposed Figure 3.1.7-1, can limit peak suppression pool temperature to a maximum of 206°F, which is well within the SSES suppression pool design limit of 220°F. In addition to providing for acceptable peak suppression pool temperatures during ATWS scenarios, 10 CFR 50.62(c)(4) requires that each BWR have a SLC system with a minimum flow capacity and boron content equivalent in control capacity to 86 gpm of 13 weight-percent sodium pentaborate solution. NEDE-31096-P-A (Reference 13) provides guidance for boron equivalency determinations. Equation 1-1 of that document may be used to demonstrate injection capacity equivalency as follows:

$$\frac{Q}{86} \times \frac{M251}{M} \times \frac{C}{13} \times \frac{E}{19.8} \geq 1$$

Where: Q = SLC system flow rate;
M = Mass of water in the reactor and Recirculation System at hot rated conditions (lbs_m);
C = Sodium pentaborate solution concentration (weight-percent); and,
E = Boron-10 isotope enrichment (19.8 atom-percent of natural boron).

For SSES, the value of M251 can be taken as 1. Applying the values of the remaining parameters, which were assumed in the CPPU ATWS analysis described in Section 9.3.3 of Attachment 4 yields:

$$\frac{40}{86}\times\frac{7}{13}\times\frac{88}{19.8}=1.11$$

Thus, the equivalency requirement of 10 CFR 50.62 is satisfied.

There are minimal, if any impacts of the new sodium pentaborate solution on the mechanical and electrical aspects of the SLC system. The SLC pump, motor, and system valves are all adequate to transport the required minimum flow rate to the reactor vessel under worst case postulated operating conditions. In addition, since only one pump operation is required, the margin between the maximum pump discharge pressure and the nominal setpoint of the pump discharge relief valve is increased from 105 psi to 250 psi; mainly due to a lower system back pressure, which results from lower pipe line losses.

In a separate license amendment request, PPL has proposed the implementation of an Alternative Source Term (AST), which, with specific exemptions, complies with the guidance given in RG 1.183 and US NRC Standard Review Plan 15.01 (Reference 3). Under the provisions of that request, the SLC system can be used to maintain suppression pool pH level above 7 following any DBA-LOCAs which would involve significant fission product releases. The revised sodium pentaborate solution requirements were evaluated using the methodologies outlined in NUREG/CR5950 (Reference 14), NUREG-1081 (Reference 15), and NUREG/CR-5732 (Reference 16). That evaluation demonstrated that the SLC system will meet this post-LOCA suppression pool pH control design function.

LPRM Calibration Interval Technical Specification Change

Technical Specification SR 3.3.1.1.8 establishes an LPRM calibration frequency of 1000 MWD/MT average core exposure. The proposed change would increase the interval between whole core LPRM calibrations to 2000 MWD/MT.

The APRM and RBM systems are the only nuclear instrumentation systems which use LPRM readings. The APRM readings are maintained within the calibration criteria by manual calibration against weekly heat balance calculations. SSES uses improved LPRM chambers which are NA 300 series. The LPRM calibration interval extension has no significant effect on the APRM accuracy during the power maneuvers or transients between LPRM calibrations. For the ARTS based RBM, when a rod is selected, the RBM channel readings are automatically calibrated to a fixed reference value which is independent of the APRM reading. The proposed use of the ARTS based RBM is currently under NRC review. Therefore, it is concluded that the performance of the APRM and RBM systems are not significantly affected by the proposed LPRM surveillance interval increase.

The justification to increase the surveillance interval is based on the assumptions used in the safety limit analysis methodology (Reference 17). The safety limit analysis uses an assembly power uncertainty value which includes a component of LPRM depletion uncertainty. This uncertainty component is due to the sensitivity changes during irradiation. The uncertainty component is primarily a function of thermal fluence since the last calibration. The safety limit analysis is performed using an uncertainty based upon the calibration interval of 2500 effective full power hours (EFPH) according to the original power densities so this is equivalent to approximately 2500 MWD/MT. The proposed value of 2000 MWD/MT is chosen to allow for a 25% surveillance extension which is supported by the value used in the safety limit determination. The 25% extension facilitates surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the surveillance (e.g., transient conditions or other ongoing surveillance or maintenance activities). A 25% extension of the specified frequency would result in conducting the surveillance prior to 2500 MWD/MT.

In addition, SSES uses the Framatome POWERPLEX core monitoring system which employs nodal diffusion theory, coupled with plant data and the improved flux instrumentation. The POWERPLEX system is based on accepted BWR calculation methods used to monitor on-line core performance and thus allows accurate assessment of thermal limits.

RHR Service Water System and Ultimate Heat Sink Technical Specification and Methods Change

The UHS is designed to supply the RHRSW and ESW systems with the cooling capacity required during a combination LOCA/LOOP for 30 days without fluid addition. The post-LOCA UHS heat load increases as a result of CPPU, primarily due to increased decay heat. The revised analysis used decay heat values calculated per the ANSI/ANS 5.1-1979 decay heat model, with a two-sigma uncertainty, instead of the Branch Technical Position ASB 9-2 model, which is the current SSES licensing basis. Approval of this element of the UHS performance analysis is requested since it is a change to the current methodology, which results in less conservative results.

The manual spray array bypass isolation valves and the small spray arrays are credited in the UHS safety analysis performed to demonstrate that the UHS will maintain a maximum design temperature of 97°F following a design basis LOCA in one unit and concurrent safe shutdown of the other unit under CPPU conditions. PPL proposes to modify the Residual Heat Removal Service Water (RHRSW) and Ultimate Heat Sink (UHS) systems.

Currently, the worst case single failure for the UHS System is the failure of a bypass line motor operated isolation valve to close when required. In the event of a failure of the bypass line's motor operated valve to close, the RHRSW and ESW system heat loads on the affected loop cannot be adequately cooled due to the large amount of water left unsprayed (i.e., heat addition to the UHS) via the bypass line at CPPU conditions.

To improve system reliability and performance, an additional manually operated valve is being installed in each spray array bypass line. This valve provides redundant capability to isolate the bypass line in the event of a failure of the motor operated bypass line isolation valve to close and establish spray cooling operations on the affected loop. The Technical

Specification changes are proposed to assure that the manual bypass valves will be capable of isolating the spray bypass line in the event of a failure of the motor operated bypass valve. The Technical Specifications for ESW are not affected.

The large spray array in each loop is capable of passing full flow and dissipating the full design basis heat load from the RHRSW and ESW systems. The small spray array is required for heat dissipation when low system flows are required. Failure of a large spray array isolation valve to open would require reduction of system flow within 3 hours after the start of a design basis event, when full system flow is no longer required. System flow would be through the bypass line during the first three hours. Starting at 3 hours, the small spray array would be needed to dissipate heat in the loop that included the failed large spray array isolation valve. The Technical Specification Changes are proposed to provide reasonable assurance that the small spray array isolation valves will be capable of being operated in the event that its use is required. Consistent with the design requirements for RHRSW, the new manual valves will be installed per ASME Section III, Class 3 requirements.

The spray array bypass lines flow into the UHS above the water line. Flow through these lines is readily identified locally by visual observation. As part of CPPU implementation, operating procedures will be revised to require visual confirmation of the absence of flow through the bypass lines when the sprays are called upon to operate. This provides positive indication that the existing motor operated spray array bypass valve has closed. In the event that flow in the bypass line is observed, an operator will be dispatched to close the new manually operated spray array bypass valve.

Personnel called upon to observe bypass line flow and operate the new manual spray array bypass valve will not need to traverse radiation fields or other harsh environmental conditions. Therefore, there are no dose consequences or personnel safety issues due to operation of the new valve. Necessary communications can be accomplished via existing radio communications capabilities and no additional communications equipment is required. The minimum required staffing level specified in TS is adequate for these actions. Training is planned on the use of the new valve. Appropriate procedure(s) will be revised or developed to control its operation.

It is proposed that the manual spray array bypass valves be added as components that must be operable in a new proposed Table 3.7.1-3. The current Required Actions and Completion times that apply when the motor operated bypass valves are inoperable will apply when the manual spray array bypass valves are inoperable. The application of these Required Actions and Completion times to the manual spray array bypass valves is conservative since the manual spray array bypass isolation valves perform the same function as the motor operated bypass isolation valves but are only required in the event of a single failure.

Similar rationale applies to the addition of the small spray array isolation valves to Table 3.7.1-1 as components that must be operable to meet LCO 3.7.1. The Required Actions and Completion times that apply when the large spray array isolation valves are inoperable will apply when the small spray array isolation valves are inoperable. The application of these Required Actions and Completion times to the small spray bypass isolation valves is conservative since the small spray array isolation valves perform the same function as the motor operated bypass isolation valves but only in the event of a single failure.

The staff's consideration regarding the use of the ANSI/ANS 5.1-1979 decay heat model is documented in References 1 and 18. While this model is not part of the SSES Current Licensing Basis, it provides for a conservative projection of long-term decay heat loads, and its use has been previously accepted by the staff on plant specific bases, as described in the cited references.

As a result of the discussion presented in this section, the overall effect of the proposed Technical Specification change is to ensure that the RHRSW and UHS systems meet their design intent and perform their design function in the event of a design basis accident at CPPU conditions.

Containment Analysis Methods Change

The existing computer program of record for the SSES DBA-LOCA long-term suppression pool temperature response is the GE SHEX methodology, and thus, the continued use of this methodology is consistent with the SSES Current Licensing Basis. However, two analytical elements, which are consistent with GE standards for containment re-evaluations, are not part of the SSES Current Licensing Bases. These elements are: 1) crediting the presence of passive heat sinks; and, 2) the ANSI/ANS 5.1-1979 decay heat model, with a two-sigma uncertainty.

The practice of crediting passive heat sinks is discussed in Branch Technical Position CSB 6-1 (Reference 19). The current SSES containment analysis does not credit passive heat sinks of any kind. The updated SSES CPPU analysis credits structural steel, and the containment liner, while conservatively not crediting the thermal mass of concrete structures. The use of these heat sinks is consistent with the limitations of the SHEX code, and provides a realistic model of this natural phenomenon.

The staff's consideration regarding the use of the GE SHEX code, along with the ANSI/ANS 5.1-1979 decay heat model, is documented in References 1 and 20. While this model is not part of the SSES current licensing basis, it provides for a conservative projection of long-term containment heat loads, and its use has been previously accepted by the staff on plant specific bases, as described in the cited references. The use of this decay heat model is also consistent with the limitations and restrictions of the SHEX code.

It is therefore concluded that the use of these elements provides for an acceptable method of calculating the long-term containment response to DBA-LOCA scenarios.

Main Turbine Pressure Regulation System

The proposed Technical Specification 3.7.8 requires that the operability of the main turbine pressure regulation system is monitored so that proper thermal limits can be administered.

The proposed Technical Specification parallels the existing Technical Specification 3.7.6 for the Main Turbine Bypass System.

Analyses for limiting fuel thermal margin transient events were performed for CPPU conditions. Typically, the limiting events for a reload analysis are the Generator Load Rejection Without Bypass (GLRWOB) event or a Control Rod Withdrawal Error (CRWE) depending on the assumptions used for the Rod Block Monitor (RBM). The results of the transient analyses for CPPU have identified that the Pressure Regulator Failure Downscale (PRFDS) event without a backup pressure regulator can become a limiting event. The analysis assumes that the backup pressure regulator is in an Out Of Service (OOS) condition. The severity of the PRFDS event is governed by the operability of the main turbine pressure regulation system.

A failure of the controlling pressure regulator with the backup pressure regulator operable results in a mild pressure disturbance similar to a pressure setpoint change and no significant reduction in fuel thermal margins occur. If the backup pressure regulator also fails downscale or is out of service when the controlling regulator fails downscale, the TCVs will close in the servo or normal operating mode. Since the TCV closure is not a fast closure, there is no loss of EHC pressure to provide an anticipatory scram. The reactor pressure will increase to the point that a high neutron flux or a high reactor pressure scram is initiated to shut down the reactor. The increase in flux and pressure affects both MCPR and LHGR during the event. An inoperable Main Turbine Pressure Regulation System may require a MCPR and / or LHGR penalty.

Technical Specification 3.7.8 is proposed because it would provide explicit protection of the MCPR Safety Limit and 1% cladding strain limit, by establishing appropriate thermal limits. These thermal limits would be a function of the operability of the main turbine pressure regulation system. The appropriate thermal limits for a pressure regulator out of service would be determined from those specified in the COLR from the reload analysis.

5. REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration

PPL Susquehanna has evaluated whether or not a significant hazards consideration is involved with the proposed change, 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?

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Response: No.

The probability (frequency of occurrence) of Design Basis Accidents occurring is not affected by the increased power level, because Susquehanna continues to comply with the regulatory and design basis criteria established for plant equipment. A probabilistic risk assessment demonstrates that the calculated core damage frequencies do not significantly change due to Constant Pressure Power Uprate (CPPU). Scram setpoints (equipment settings that initiate automatic plant shutdowns) are established such that there is no significant increase in scram frequency due to CPPU. No new challenges to safety-related equipment result from CPPU.

The changes in consequences of postulated accidents, which would occur from 102% of the CPPU (rated thermal power) RTP compared to those previously evaluated, are acceptable. The results of CPPU accident evaluations do not exceed the NRC-approved acceptance limits. The spectrum of postulated accidents and transients has been investigated, and are shown to meet the plant's currently licensed regulatory criteria. In the area of fuel and core design, for example, the Safety Limit Minimum Critical Power Ratio (SLMCPR) and other applicable Specified Acceptable Fuel Design Limits (SAFDLS) are still met. Continued compliance with the SLMCPR and other SAFDLs will be confirmed on a cycle specific basis consistent with the criteria accepted by the NRC.

Challenges to the Reactor Coolant Pressure Boundary were evaluated at CPPU conditions (pressure, temperature, flow, and radiation) were found to meet their acceptance criteria for allowable stresses and overpressure margin.

Challenges to the containment have been evaluated, and the containment and its associated cooling systems continue to meet 10 CFR 50, Appendix A, Criterion 16, Containment Design; Criterion 38, Containment Heat Removal; and Criterion 50, Containment Design Basis. The increase in the calculated post LOCA suppression pool temperature above the currently assumed peak temperature was evaluated and determined to be acceptable.

Radiological release events (accidents) have been evaluated, and shown to meet the guidelines of 10 CFR 50.67.

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

Standby Liquid Control (SLC) System Technical Specification Change

Response: No.

The proposed changes revise Technical Specification 3.1.7 for the SLC system to reflect new boron weight-percent, concentration, and enrichment requirements. In addition, with the transition from two pumps to single pump operation, the proposed changes reduce the required SLC pump flow and discharge pressure needed for compliance with 10 CFR 50.62, thus increasing the reliability of the system. The changes do not otherwise alter the design or operation of the SLC system, and the existing design of the system is sufficient to transport the enriched sodium pentaborate solution. The SLC system is not considered to be the initiator of any event currently analyzed in the FSAR. Therefore, the proposed changes do not increase the probability of a previously evaluated accident.

The SSES CPPU ATWS analysis was performed by GE in accordance with the guidance provided in NEDC-32424P-A (Reference 12), and used standard accepted assumptions, inputs, and codes. That analysis, which demonstrated that the acceptance criteria for peak vessel pressure, peak cladding temperature, peak local cladding oxidation, peak suppression pool temperature, and peak containment pressure, established the requirements for the proposed boron weight-percent and concentration, and pump flow rate. Also note that the CPPU ATWS analysis assumed the availability of only a single pump, versus two pumps. As a result, no fission product barriers are adversely challenged, and the radiological consequences of previously evaluated accidents (i.e., ATWS) are not increased.

PPL has submitted a license amendment request to change the SSES DBA-LOCA source term licensing basis to 10 CFR 50.67, i.e., Alternate Source Term (Reference 3). Under the provisions of that request, the SLC system can be used to maintain suppression pool pH level above 7 following a DBA-LOCA which could involve significant fission product releases. The revised sodium pentaborate solution requirements were evaluated using the methodologies outlined in NUREG/CR5950 (Reference 14), NUREG-1081 (Reference 15), and NUREG/CR-5732 (Reference 16). That evaluation demonstrated that the SLC system will meet this post-LOCA suppression pool pH control design function.

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

LPRM Calibration Interval Technical Specification SR Frequency Change

Response: No.

The revised surveillance interval continues to ensure that the LPRM signal is adequately calibrated. This change will not alter the basic operation of process variables, structures, systems, or components as described in the SSES FSAR, and no new equipment is introduced by the change in LPRM surveillance interval. The performance of the APRM and RBM systems is not significantly affected by the proposed LPRM surveillance interval increase. Therefore, the probability of accidents previously evaluated is unchanged.

The proposed change results in no change in radiological consequences of the design basis LOCA as currently analyzed for SSES. The consequences of an accident can be affected by the thermal limits existing at the time of the postulated accident, but LPRM chamber exposure has no significant effect on the calculated thermal limits because LPRM accuracy does not significantly deviate with exposure. For the extended calibration interval, the assumption in the safety limit analysis remains valid, maintaining the accuracy of the thermal limit calculation. Therefore, the thermal limit calculation is not significantly affected by LPRM calibration frequency and the consequences of an accident previously evaluated are unchanged.

The change does not affect the initiation of any event, nor does it negatively impact the mitigation of any event. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

RHR Service Water System and Ultimate Heat Sink Technical Specification and Methods Change

Response: No.

The proposed changes do not involve any new initiators for any accidents nor do they increase the likelihood of a malfunction of any Structures, Systems or Components (SSCs). Implementation of the subject changes reduces the probability of adverse consequences of accidents previously evaluated, because inclusion of the manual spray array bypass isolation valves and the small spray array isolation valves in the Technical Specifications (TS) increases their reliability to function for safe shutdown.

The use of the ANS/ANSI-5.1-1979 decay heat model in the UHS performance analysis is not relevant to accident initiation, but rather, pertains to the method used to evaluate currently postulated accidents. Its use does not, in any way, alter existing fission product boundaries, and provides a conservative prediction of decay heat. Therefore, the change in decay heat calculational method does not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

Containment Analysis Methods Change

Response: No.

The use of passive heat sinks, and the ANS/ANSI-5.1-1979 decay heat model are not relevant to accident initiation, but rather, pertain to the method used to evaluate postulated accidents. The use of these elements does not, in any way, alter existing fission product boundaries, and provides a conservative prediction of the containment response to DBA-LOCAs. Therefore the Containment Analysis Method Change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

Main Turbine Pressure Regulation System

Response: No.

Technical Specification 3.7.8 does not directly or indirectly affect any plant system, equipment, component, or change the process used to operate the plant. Technical Specification 3.7.8 would ensure acceptable performance, since it would establish requirements for adhering to the appropriate thermal limits, depending on the operability of the main turbine pressure regulation system. Use of the appropriate limits assures that the appropriate safety limits will not be exceeded during normal or anticipated operational occurrences. Thus, Technical Specification 3.7.8 does 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?

Extended Power Uprate

Response: No.

Equipment that could be affected by EPU has been evaluated. No new operating mode, safety-related equipment lineup, accident scenario, or equipment failure mode was identified. The full spectrum of accident considerations has been evaluated and no new or different kind of accident has been identified. CPPU uses developed technology and applies it within capabilities of existing or modified plant safety related equipment in accordance with the regulatory criteria (including NRC approved codes, standards and methods). No new accidents or event precursors have been identified.

The SSES TS require revision to implement EPU. The revisions have been assessed and it was determined that the proposed change will not introduce a different accident than that previously evaluated. Therefore the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

Standby Liquid Control (SLC) System Technical Specification Change

Response: No.

The proposed changes revise Technical Specification 3.1.7 for the SLC system to reflect new boron weight-percent, concentration, and enrichment requirements. In addition, with the transition from two pumps to single pump operation, the proposed changes reduce the required SLC pump flow and discharge pressure needed for compliance with 10 CFR 50.62. The changes do not otherwise alter the design or operation of the SLC system, and the existing design of the system is sufficient to process the enriched sodium pentaborate solution. With the exception of these changes, no other physical changes to plant structures or systems are proposed. In addition, a new Surveillance Requirement (SR 3.1.7.10) is added to ensure that the correct enrichment is verified prior to addition of inventory to the SLC tank. Thus, the proposed changes do not create a new initiating event for the spectrum of events currently postulated in the FSAR.

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

LPRM Calibration Interval Technical Specification SR Frequency Change

Response: No.

The proposed change will not physically alter the plant or its mode of operation. The performance of the APRM and RBM systems is not significantly affected by the proposed LPRM surveillance interval increase. As such, no new or different types of equipment will be installed and the basic operation of installed equipment is unchanged. The methods of governing plant operation and testing are consistent with current safety analysis assumptions. Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

RHR Service Water System and Ultimate Heat Sink Technical Specification and Methods Change

Response: No.

The subject changes apply Technical Specification controls to new UHS manual bypass isolation valves and the existing small spray array isolation valves. The design functions of the systems are not affected.

The addition of manually operated valves in the system, operational changes and the Technical Specification changes do not create the possibility of a new or different kind of accident from any previously evaluated.

The use of the ANS/ANSI-5.1-1979 decay heat model is not relevant to accident initiation, but rather pertains to the method used to evaluate currently postulated accidents. The use of this analytical tool 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 in the FSAR. Further, it does not result in the need to postulate any new accident scenarios. Therefore the decay heat calculational method change does not create the possibility of a new or different kind of accident from any accident previously evaluated

Containment Analysis Methods Change

Response: No.

The use of passive heat sinks and the ANS/ANSI-5.1-1979 decay heat model are not relevant to accident initiation, but pertain to the method used to evaluate currently postulated accidents. The use of these analytical tools 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 in the FSAR. Further, they do not result in the need to postulate any new accident scenarios. Therefore the Containment Analysis Method Change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

Main Turbine Pressure Regulation System

Response: No.

Technical Specification 3.7.8 will not directly or indirectly affect any plant system, equipment, or component and therefore does not affect the failure modes of any of these items. Thus, Technical Specification 3.7.8 does not create the possibility of a previously unevaluated operator error or a new single failure.

Therefore, Technical Specification 3.7.8 does not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

Extended Power Uprate

Response: No.

The CPPU affects only design and operational margins. Challenges to the fuel, reactor coolant pressure boundary, and containment were evaluated for CPPU conditions. Fuel integrity is maintained by meeting existing design and regulatory limits. The calculated loads on affected structures, systems and components, including the reactor coolant pressure boundary, will remain within their design allowables for design basis event categories. No NRC acceptance criterion is exceeded. Because the SSES configuration and responses to transients and postulated accidents do not result in exceeding the presently approved NRC acceptance limits, the proposed changes do not involve a significant reduction in a margin of safety.

Standby Liquid Control (SLC) System Technical Specification Change

Response: No.

The proposed changes revise Technical Specification 3.1.7 for the SLC system to reflect new boron weight-percent, concentration, and enrichment requirements. In addition, with the transition from two to single pump operation the proposed changes reduce the required SLC pump flow and discharge pressure needed for compliance with 10 CFR 50.62, thus increasing the reliability of the system. The changes do not otherwise alter the design or operation of the SLC system, and the existing design of the system is sufficient to process the enriched sodium pentaborate solution.

The CPPU ATWS analysis was performed in accordance with the guidance provided in NEDC-32424P-A (Reference 12), and used standard accepted assumptions, inputs, and codes. That analysis, which demonstrated that ATWS acceptance criteria are satisfied, established the requirements for the proposed boron weight-percent and concentration, and pump flow rate. Further, the CPPU ATWS analysis assumed only a single pump flow verses two pumps.

With respect to the proposed use of the SLC system for maintaining suppression pool pH level above 7 following a DBA-LOCAs, the revised sodium pentaborate solution requirements were evaluated using the methodologies outlined in US NRC NUREG/CR-5950, Rev. 3, "Iodine Evolution and pH Control," December 1992; USNRC NUREG-1081, "Post Accident Gas Generation from Radiolysis of Organic Materials," September 1984 and USNRC NUREG/CR-5732, "Iodine Chemical Forms in LW Severe Accidents," April 1992. That evaluation demonstrated that the SLC system can meet this post-LOCA suppression pool pH control design function.

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

LPRM Calibration Interval Technical Specification Change

Response: No.

The proposed change has no impact on equipment design or fundamental operation and there are no changes being made to safety limits or safety system allowable values that would adversely affect plant safety as a result of the proposed change. The performance of the APRM and RBM systems is not significantly affected by the proposed LPRM surveillance interval increase. The margin of safety can be affected by the thermal limits existing prior to an accident; however, uncertainties associated with LPRM chamber exposure have no significant effect on the calculated thermal limits. For the extended calibration interval, the assumption in the safety limit analysis remains valid, maintaining the accuracy of the thermal limit calculation.

Since the proposed change does not affect safety analysis assumptions or initial conditions, the margin of safety in the safety analyses are maintained. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

RHR Service Water System and Ultimate Heat Sink Technical Specification and Methods Change

Response: No.

Implementation of the subject changes does not significantly reduce the margin of safety since these changes add components and Technical Specification controls for the components not currently addressed in the Technical Specifications. These changes increase the reliability of the affected components/systems to function for safe shutdown.

Therefore these changes do not involve a significant reduction in margin of safety.

The ANS/ANSI-5.1-1979 model provides a conservative prediction of decay heat. The use of this element is consistent with current industry standards, and has been previously accepted by the staff for use in containment analysis by other licensees, as described in GE Nuclear Energy. "Constant Pressure Power Uprate," Licensing Topical Report NEDC-33004P-A, Revision 4, dated July 2003; and the letter to Gary L. Sozzi (GE) from Ashok Thandani (NRC) on the Use of the SHEX Computer Program and ANSI/ANS 5.1-1979, "Decay Heat Source Term for Containment Long-Term Pressure and Temperature Analysis," July 13, 1993. Therefore, the decay heat calculational method change does not involve a significant reduction in the margin of safety.

Containment Analysis Methods Change

Response: No.

The use of passive heat sinks and the ANS/ANSI-5.1-1979 decay heat model are realistic phenomena, and provide a conservative prediction of the plant response to DBA-LOCAs. The use of these elements is consistent with current industry standards, and has been previously accepted by the staff for other licensees, as described in GE Nuclear Energy: "Constant Pressure Power Uprate," Licensing Topical Report NEDC-33004P-A, Revision 4, dated July 2003; the letter to Gary L. Sozzi (GE) from Ashok Thandani (NRC) on the Use of the SHEX Computer Program; and ANSI/ANS 5.1-1979, "Decay Heat Source Term for Containment Long-Term Pressure and Temperature Analysis,"
July 13, 1993. Therefore the Containment Analysis Method Change does not involve a significant reduction in the margin of safety.

Main Turbine Pressure Regulation System

Since Technical Specification 3.7.8 does not alter any plant system, equipment, component, or processes used to operate the plant, the proposed change will not jeopardize or degrade the function or operation of any plant system or component governed by Technical Specifications. Technical Specification 3.7.8 preserves the margin of safety by establishing requirements for adhering to the appropriate thermal limits.

Conclusion for All Changes

Based upon the above, PPL Susquehanna 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.

5.2 Applicable Regulatory Requirements / Criteria

5.2.1 Analysis

Extended Power Uprate

10 CFR 50.36 (c)(2)(ii) Criterion 2, requires that TS LCOs include process variables, design features, and operating restrictions that are initial conditions of design basis accident analysis. The Technical Specifications ensure that the SSES system performance parameters are maintained within the values assumed in the safety analyses. The Technical Specification changes are supported by the safety analyses that were performed consistent with NRC approved methodology approved for SSES and continue to provide a comparable level of protection as the current Technical Specifications. Applicable regulatory requirements and significant safety evaluations performed in support of the proposed changes are described in Attachment 4.

Standby Liquid Control (SLC) System Technical Specification Change

10 CFR 50, Appendix A, GDC 26 requires that two independent reactivity control systems of different design principles be provided. For SSES, these systems are: the Control Rod Drive (CRD) system and the SLC system, which is the subject of the proposed Technical Specification changes. The evaluations described in Attachment 4, Sections 6.5, 9.3.1, and 9.3.3 demonstrate that the SLC system continues to satisfy the provisions of this GDC.

10 CFR 50, Appendix A, GDC 27 requires that the reactivity control systems have the combined capability to assure that under postulated accident conditions, with sufficient margin to account for stuck control rods, that the capability to adequately cool the core is maintained. The evaluations described in Attachment 4, Sections 6.5, 9.3.1, and 9.3.3 (ATWS) demonstrate that the SLC system continues to satisfy the provisions of this GDC.

10 CFR 50.62(c)(4) states in part: "Each BWR must have a SLC system with a minimum flow capacity and boron content equivalent in control capacity to 86 gpm of 13 weight-percent sodium pentaborate solution." NEDE-31096-P-A provides guidance for boron equivalency determinations. The application of this guidance demonstrates that the equivalency requirement of 10 CFR 50.62 are met.

LPRM Calibration Interval Technical Specification Change

10 CFR 50.36(c)(3) requires that TS LCOs include surveillance requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within

safety limits, and that the limiting conditions for operation will be met. The Technical Specification changes are supported by the safety analyses that were performed consistent with NRC approved methodology and continue to provide a comparable level of protection as the current Technical Specifications. Significant Safety evaluations performed in support of the proposed changes are described in
Attachment 4.

RHR Service Water System and Ultimate Heat Sink Technical Specification and Methods Change

GDC-5 requires SSCs important to safety not to be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units. The proposed changes do not affect compliance with GDC-5 as described in FSAR Section 3.1. The RHRSW system and UHS continue to be designed such that no single failure will prevent it from achieving its safety function.

GDC-44 requires that a system to transfer heat from structures, systems, and components important to safety to an ultimate heat sink be provided. The system safety function shall be to transfer the combined heat load of these structures, systems, and components under normal operating and accident conditions. The proposed change does not affect compliance with GDC-44 as described in FSAR Section 3.1. The RHRSW system is designed to Seismic Category I requirements. Redundant safety related components served by RHRSW are supplied through redundant supply headers and returned through redundant discharge or return lines. Electric power for operation of redundant safety related components of RHRSW is supplied from separate independent offsite and redundant onsite standby power sources. No single active failure renders RHRSW incapable of performing its safety function.

Regulatory Guide 1.27 Revision 2 applies to nuclear power plants that use water as the ultimate heat sink. The proposed change does not affect compliance with Regulatory Guide 1.27 Revision 2 as described in Sections 3.13 and 9.2.7 of the FSAR. The UHS continues to be capable of providing sufficient cooling for 30 days to permit simultaneous safe shutdown and cooldown of both SSES units and maintain them in a safe shutdown condition.

10 CFR 50.36(c)(3), requires that Technical Specification LCOs include surveillance requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions for operation will be met. The Technical Specification changes are supported by the safety analyses that were performed consistent with NRC approved methodology and continue to provide a comparable level of protection as current Technical Specifications.

Containment Analysis Methods Change

10 CFR 50, Appendix A, GDC-16 requires that a reactor containment be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity, and that it be assured that containment design parameters important to safety not be exceeded for as long as postulated accident conditions require. The evaluations described in Attachment 4, Section 4.1 demonstrate that containment parameters stay within their design limits.

10 CFR 50, Appendix A, GDC-50 requires that the reactor containment structure be designed so that the structure and its internal compartments can accommodate the calculated pressure and temperature conditions resulting from any loss of coolant accident. The evaluations described in Attachment 4, Section 4.1 demonstrate that containment parameters stay within their design limits.

Main Turbine Pressure Regulation System

Title 10 of the Code of Federal Regulations (10 CFR) establishes the fundamental regulatory requirements with respect to reactivity control systems. Specifically, General Design Criterion 10 (GDC 10), "Reactor design," in Appendix A, "General Design Criteria for Nuclear Power Plants," 10 CFR Part 50 states, in part, that the reactor core and associated coolant, control, and protection systems shall be designed with appropriate margin to assure that specified acceptable fuel design limits are not exceeded.

Technical Specification 3.7.8 will ensure that the MCPR Safety Limit will not be violated and that fuel cladding strain will not exceed 1%. This satisfies the requirement of GDC-10 regarding acceptable fuel design limits.

5.2.2 Conclusion

Based on the analyses provided in Section 4, Technical Analysis, the proposed change is consistent with applicable regulatory requirements and criteria. In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

6. ENVIRONMENTAL CONSIDERATION

Proposed Changes for Extended Power Uprate

The proposed Operating License and Technical Specification changes required for implementation of EPU meet the requirements for an environmental review as set forth in 10 CFR 51.20, "Criteria For And Identification Of Licensing And Regulatory Actions Requiring Environmental Impact Statements". A supplement to the Susquehanna Environmental Report in Attachment 3 concludes the following:

Normal operation radiation levels are expected to increase by no more than the percentage increase of the EPU. The increase in radiation levels is not expected to have any significant effect on the plant radiation shielding and would be offset by conservatism in the original design, source terms used, and analytical techniques. All offsite radiation doses would be within applicable regulatory standards.

PPL Susquehanna concludes that the environmental impacts of operation at 3,952 MWt are either bounded by impacts described in earlier National Environmental Policy Act (NEPA) assessments or within regulatory permitted limits. As a consequence, PPL Susquehanna believes that the EPU would not significantly (as defined in 40 CFR 1508.27) affect human health or the environment.

Other Proposed Changes:

Standby Liquid Control System Technical Specifications, LPRM Technical Specification Surveillance Interval, RHR Service Water System and Ultimate Heat Sink Technical Specification; and Methods Change; and Containment Analysis Methods Change
Main Turbine Pressure Regulation System

A review has determined that these other proposed changes would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, these proposed changes do not involve (i) a significant hazards consideration, (ii), a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, these proposed changes meet the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with these proposed changes.

7. REFERENCES

1. GE Nuclear Energy. "Constant Pressure Power Uprate," Licensing Topical Report NEDC-33004P-A, Revision 4 dated July 2003.

2. PPL Letter PLA-5933, Britt T. McKinney to USNRC "Susquehanna Steam Electric Station Proposed Amendment No. 280 to Unit 1 Facility Operating License NPF-14 and Proposed Amendment No. 249 to Unit 2 Facility Operating License NPF-22: Revise Technical Specification 3.4.10 RCS Pressure and Temperature (P/T) Limits," dated October 5, 2005.

3. PPL Letter PLA-5963, Britt T. McKinney (PPL) to USNRC, "Susquehanna Steam Electric Station Proposed Amendment No. 281 to License NPF-14 and Proposed Amendment No. 251 to License NPF-22: Application for License Amendment and Related Technical Specification Changes to Implement Full-Scope Alternative Source Term in Accordance With 10 CFR 50.67," dated October 13, 2005.

4. PPL Letter PLA-5931, Britt T. McKinney (PPL) to USNRC, "Susquehanna Steam Electric Station Proposed License Amendment Numbers 279 for Unit 1 Operating License No. NPF-14 and 248 for Unit 2 Operating License No. NPF-22 ARTS/MELLLA Implementation," dated November 18, 2005.

5. PPL Letter PLA-5880, Britt T. McKinney (PPL) to USNRC "Susquehanna Steam Electric Station Proposed License Amendment Numbers 272 for Unit 1 Operating License No. NPF-14 and 241 for Unit 2 Operating License No. NPF-22 Power Range Neutron Monitor System Digital Upgrade," dated June 27, 2005.

6. US NRC NUREG-1433, Revision 3, "Standard Technical Specifications General Electric Plants, BWR/4," June 2004.

7. PPL Letter PLA-3788, H. W. Keiser (PPL) to C. L. Miller (NRC) "Susquehanna Steam Electric Station Submittal of Licensing Topical Report On Power Uprate With Increased Flow," dated June 15, 1992.

8. PPL Letter PLA-4055, George T. Jones (PPL) to C. L. Miller (NRC) "Susquehanna Steam Electric Station Proposed Amendment No. 117 to License No. NPF-22: Power Uprate With Increased Flow," dated November 24, 1993.

9. PPL Letter PLA-4173, Robert G. Byram (PPL) to C. L. Miller (NRC) "Susquehanna Steam Electric Station Proposed Amendment No. 168 to License No. NPF-14: Power Uprate With Increased Flow," dated July 27, 1994.

10. PPL Letter PLA-5212, Robert G. Byram (PPL) to USNRC, "Susquehanna Steam Electric Station Proposed License Amendment No 235 to License NPF-14 and Proposed amendment No. 200 to NPF-22: Power Uprate," dated October 30, 2000.

11. Letter from US NRC to Mr. J.S. Keenan, "Brunswick Steam Electric Plant, Units 1 And 2 - Issuance Of Amendments RE: Standby Liquid Control Sodium Pentaborate Solution Requirements," March 25, 2003 (i.e., Amendment 227 and 255 For Brunswick Units 1 and 2).

12. GE Nuclear Energy, "Generic Guidelines For General Electric Boiling Water Reactor Extended Power Uprate," NEDC-32424P-A, Class III, (ELTR-1) February 1999.

13. GE Nuclear Energy, "Anticipated Transients Without SCRAM, Response To NRC ATWS Rule, 10 CFR 50.62," NEDE-31096-P-A, Class III, February 1987.

14. US NRC NUREG/CR5950, Revision 3, "Iodine Evolution And pH Control," December 1992.

15. US NRC NUREG-1081, "Post Accident Gas Generation From Radiolosis Of Organic Materials", September 1984.

16. US NRC NUREG/CR-5732, "Iodine Chemical Forms In LW Severe Accidents," April 1992.

17. ANF-524(P)(A) Revision 2 and Supplements 1 and 2, *ANF Critical Power Methodology for Boiling Water Reactors*, Advanced Nuclear Fuels Corporation, November 1990.

18. Letter to Gary L. Sozzi (GE) from Ashok Thadani (NRC) on the Use of the SHEX Computer Program and ANSI/ANS 5.1-1979 Decay Heat Source Term for Containment Long-Term Pressure and Temperature Analysis, July 13, 1993.

19. Branch Technical Position CSB 6-1, "Minimum Containment Pressure Model For PWR ECCS Performance Evaluation" (NUREG-0800, Section 6.2.1.5), Rev. 2, July 1981.

20. PPL Letter PLA-5990, Britt T. McKinney (PPL) to USNRC, "Susquehanna Steam Electric Station Proposed Amendment No. 283 To Unit 1 License NPF-14: MCPR Safety Limits and Reference Changes," dated December 1, 2005.

Attachment 1 to PLA-6002

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

Operating License Changes
Unit 1
(Mark-up)

startup, sealed neutron sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) PPL Susquehanna, LLC, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) PPL Susquehanna, LLC, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR 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) <u>Maximum Power Level</u>

3952

PPL Susquehanna, LLC is authorized to operate the facility at reactor core power levels not in excess of ~~3489~~ megawatts thermal in accordance with the conditions specified herein and in Attachment 1 to this license. The preoperational tests, startup tests and other items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) <u>Technical Specifications and Environmental Protection Plan</u>

The Technical Specifications contained in Appendix A, as revised through Amendment No. 225, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. PPL Susquehanna, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

For Surveillance Requirements (SRs) that are new in Amendment 178 to Facility Operating License No. NPF-14, the first performance is due at the end of the first surveillance interval that begins at implementation of Amendment 178. For SRs that existed prior to Amendment 178, including SRs with modified acceptance criteria and SRs whose frequency of performance is being extended, the first performance is due at the end of the first surveillance interval that begins on the date the Surveillance was last performed prior to implementation of Amendment 178.

Technical Specifications Changes
Unit 1
(Mark-up)

1.1 Definitions (continued)

RATED THERMAL POWER (RTP)

RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3489 MWt. 3952

REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME

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

SHUTDOWN MARGIN (SDM)

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

a. The reactor is xenon free;

b. The moderator temperature is 68°F; and

c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn.

With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.

STAGGERED TEST BASIS

A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during η Surveillance Frequency intervals, where η is the total number of systems, subsystems, channels, or other designated components in the associated function.

THERMAL POWER

THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

TURBINE BYPASS SYSTEM RESPONSE TIME

The TURBINE BYPASS SYSTEM RESPONSE TIME consists of the time from when the turbine bypass control unit generates a turbine bypass valve flow signal

(continued)

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs 23

2.1.1.1 With the reactor steam dome pressure < 785 psig or core flow < 10 million lbm/hr:

THERMAL POWER shall be ≤ 25% RTP.

2.1.1.2 With the reactor steam dome pressure ≥ 785 psig and core flow ≥ 10 million lbm/hr:

MCPR shall be ≥ 1.09 for two recirculation loop operation or ≥ 1.10 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.

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 sodium pentaborate in solution IS NOT ~~≤ 13.6 weight percent but~~ within limits of Figure 3.1.7-1.	A.1 Restore concentration of sodium pentaborate in solution to within limits ~~> 13.6 weight percent.~~ OF FIGURE 3.1.7-1	~~72~~ 8 hours ~~AND~~ ~~10 days from discovery of failure to meet the LCO~~
B. One SLC subsystem inoperable for reasons other than Condition A.	B.1 Restore SLC subsystem to OPERABLE status.	7 days ~~AND~~ ~~10 days from discovery of failure to meet the LCO.~~
C. Two SLC subsystems inoperable for reasons other than Condition A.	C.1 Restore one SLC subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	12 hours

WITHIN THE LIMITS OF FIGURE 3.1.7-1.

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.1.7.1	Verify available volume of sodium pentaborate solution is ~~≥ 4587 gallons.~~	24 hours
SR 3.1.7.2	Verify temperature of sodium pentaborate solution is within the limits of Figure 3.1.7-2.	24 hours
SR 3.1.7.3	Verify temperature of pump suction piping is within the limits of Figure 3.1.7-2.	24 hours
SR 3.1.7.4	Verify continuity of explosive charge.	31 days
SR 3.1.7.5	Verify the concentration of sodium pentaborate in solution is ~~≥ 13.6 weight percent and~~ within the limits of Figure 3.1.7-1.	31 days AND Once within 24 hours after water or sodium pentaborate is added to solution AND Once within 24 hours after solution temperature is restored within the limits of Figure 3.1.7-2

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.1.7.6	Verify each SLC subsystem manual and power operated 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 1250 40.0
SR 3.1.7.7	Verify each pump develops a flow rate ≥ ~~41.2~~ gpm at a discharge pressure ≥ ~~1395~~ psig.	In accordance with the Inservice Testing Program
SR 3.1.7.8	Verify flow through one SLC subsystem pump into reactor pressure vessel.	24 months on a STAGGERED TEST BASIS
SR 3.1.7.9	Verify all heat traced piping between storage tank and pump suction is unblocked.	24 months AND Once within 24 hours after solution temperature is restored within the limits of Figure 3.1.7-2

INSERT 3.1-22A

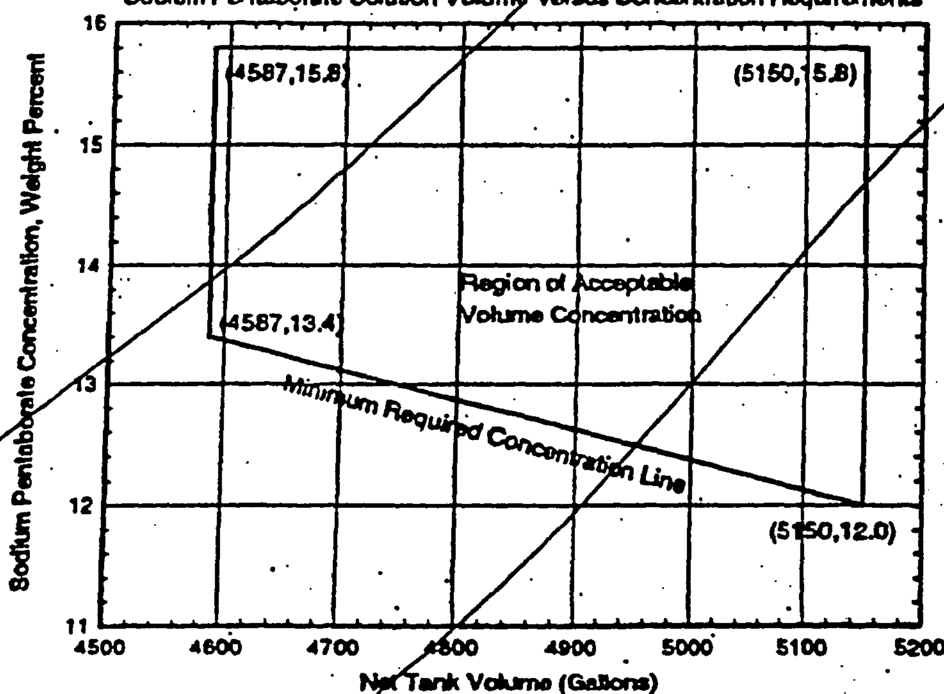
Insert 3.1-22A

SURVEILLANCE		FREQUENCY
SR 3.1.7.10	Verify sodium pentaborate enrichment is ≥ 88 atom percent B-10.	Prior to addition to SLC tank.

Insert 3.1-23A

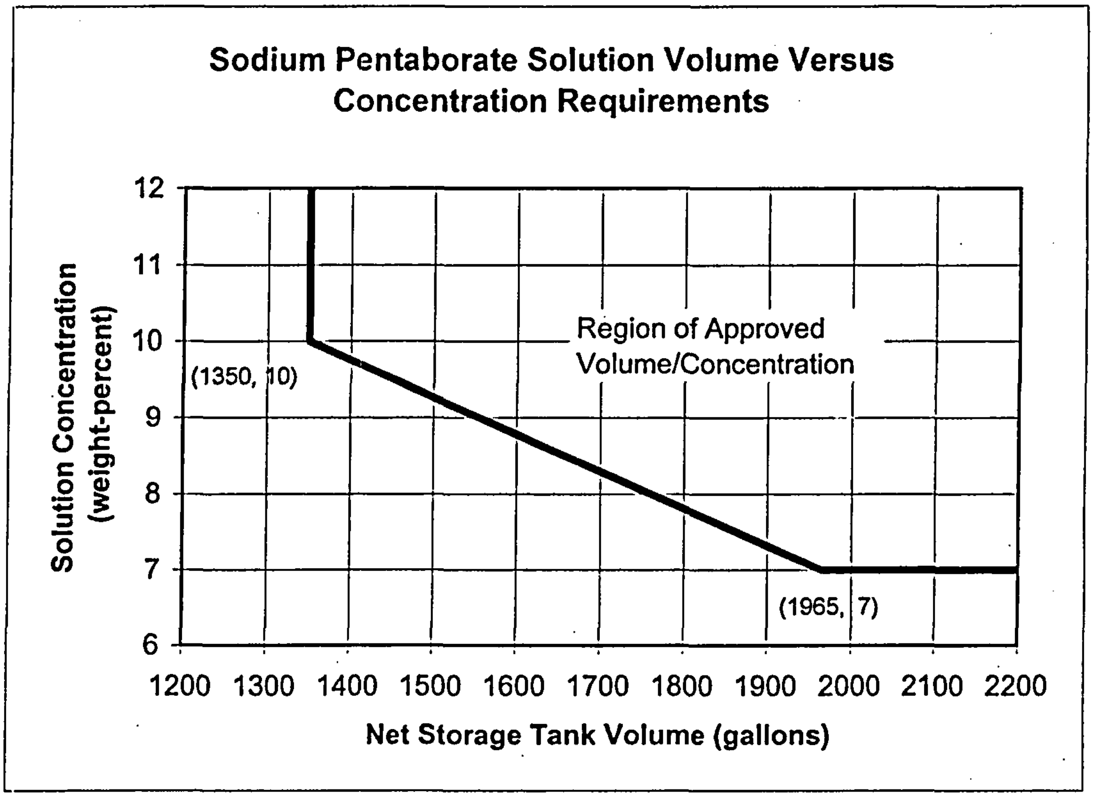
FIGURE 3.1.7-1

Sodium Pentaborate Solution Volume Versus Concentration Requirements



Insert 3.1-23A

FIGURE 3.1.7-1



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.

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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.	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 24 hours after ≥25% RTP 2.3 <u>AND</u> 24 hours thereafter <u>AND</u> Prior to exceeding 50% RTP

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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% RTP.

23

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% 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 24 hours after ≥25% RTP 23 AND 24 hours thereafter AND Prior to exceeding 60% RTP 44
SR 3.2.2.2	Determine the MCPR limits.	Once within 72 hours after each completion of SRs in 3.1.4

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.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

23

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.	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 24 hours after ≥ 25% RTP 23 AND 24 hours thereafter AND Prior to exceeding 50% RTP 44

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more Functions with RPS trip capability not maintained.	C.1 Restore RPS trip capability.	1 hour
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 channels.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1 Reduce THERMAL POWER to < 30% RTP.	4 hours 26
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1 Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1 Be in MODE 3.	12 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

(continued)

Retype to reflect PRNMS and ARTS/MELLLA

ACTIONS (continued)

CONDITION		REQUIRED ACTION		COMPLETION TIME
I.	As required by Required Action D.1 and referenced in Table 3.3.1.1-1	I.1	Initiate alternate method to detect and suppress thermal hydraulic instability oscillations.	12 hours
		<u>AND</u>		
		I.2	Restore require channels to OPERABLE.	120 days
J.	Required Action and associated Completion Time of Condition I not met.	J.1	Reduce THERMAL POWER to < ~~25~~% RTP.	4 hours

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Retype to reflect PRNMS and ARTS/MELLLA

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	Perform CHANNEL CHECK.	24 hours
SR 3.3.1.1.3	----------NOTE---------- Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. ------------------------ Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP while operating at ≥ 25% RTP.	23 7 days
SR 3.3.1.1.4	----------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

(continued)

Retype to ~~reflect~~ ~~PRNMS~~ and ARTS/~~MELLLA~~

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.6	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to fully withdrawing SRMs from the core.
SR 3.3.1.1.7	---NOTE--- Only required to be met during entry into MODE 2 from MODE 1. --- Verify the IRM and APRM channels overlap.	7 days
SR 3.3.1.1.8	Calibrate the local power range monitors.	2000 ~~1000~~ MWD/MT average core exposure
SR 3.3.1.1.9	---NOTE--- A test of all required contacts does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.1.1.10	Perform CHANNEL CALIBRATION.	92 days

(continued)

Retype ~~to~~ reflect PRNMS ~~and~~ ARTS/MELLLA

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.11	-----NOTES----- 1. Neutron detectors are excluded. 2. For Function 1.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL CALIBRATION.	184 days
SR 3.3.1.1.12	-----NOTES----- 1. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. 2. For Functions 2.b and 2.f, the CHANNEL FUNCTIONAL TEST includes the recirculation flow input processing, excluding the flow transmitters. ---------- Perform CHANNEL FUNCTIONAL TEST.	184 days
SR 3.3.1.1.13	Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.1.14	Perform CHANNEL FUNCTIONAL TEST.	24 months
SR 3.3.1.1.15	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.16	Verify Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ 30% RTP.	24 months

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(continued)

~~Retype to reflect~~ PRNMS and ARTS/MELLLA

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.17	---NOTES--- 1. Neutron detectors are excluded. 2. For Function 5 "n" equals 4 channels for the purpose of determining the STAGGERED TEST BASIS Frequency . 3. For Function 2.e, "n" equals 8 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. Testing of APRM and OPRM outputs shall alternate. --- Verify the RPS RESPONSE TIME is within limits.	24 months on a STAGGERED TEST BASIS
SR 3.3.1.1.18	---NOTES--- 1. Neutron detectors are excluded. 2. For Functions 2.b and 2.f, the recirculation flow transmitters that feed the APRMs are included. --- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.1.19	Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ 30% and recirculation drive flow is ≤ value equivalent ~~to~~ the core flow value defined in the COLR.	24 months 25
SR 3.3.1.1.20	Adjust recirculation drive flow to conform to reactor core flow.	24 months

Retype to reflect PRNMS and ARTS/MELLLA

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	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.11 SR 3.3.1.1.15	≤ 122/125 divisions of full scale
	5[(a)]	3	H	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.11 SR 3.3.1.1.15	≤ 122/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.4 SR 3.3.1.1.15	NA
	5[(a)]	3	H	SR 3.3.1.1.5 SR 3.3.2.2.15	NA
2. Average Power Range Monitors					
a. Neutron Flux—High (Setdown)	2	3[(c)]	G	SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.18	≤ 20% RTP
b. Simulated Thermal Power—High	1	3[(c)]	F	SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.18 SR 3.3.1.1.20	0.55W + 60.7 ≤ 0.62 W + 64.3% RTP[(b)] and ≤ 115.5% RTP

(continued)

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

(b) 0.62(W - ΔW) + 64.3% RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

0.55(W - ΔW) + 60.7

(c) Each APRM channel provides inputs to both trip systems

Retype to reflect PRNMS and ARTS/MELLLA

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
2. Average Power Range Monitors (continued)					
c. Neutron Flux—High	1	3(c)	F	SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.18	≤ 120% RTP
d. Inop	1, 2	3(c)	G	SR 3.3.1.1.12	NA
e. 2-Out-Of-4 Voter	1, 2	2	G	SR 3.3.1.2 SR 3.3.1.12 SR 3.3.1.15 SR 3.3.1.17	NA
f. OPRM Trip	≥ 25% RTP 23	3(c)	I	SR 3.3.1.2 SR 3.3.1.8 SR 3.3.1.12 SR 3.3.1.18 SR 3.3.1.19 SR 3.3.1.20	(d)
3. Reactor Vessel Steam Dome Pressure—High	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.15	≤ 1093 psig
4. Reactor Vessel Water Level—Low, Level 3	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.15	≥ 11.5 inches
5. Main Steam Isolation Valve—Closure	1	8	F	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ 11% closed
6. Drywell Pressure—High	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.15	≤ 1.88 psig

(continued)

(c) Each APRM channel provides inputs to both trip systems.

(d) See COLR for OPRM period based detection algorithm (PBDA) setpoint limits.

Retype to reflect PRNMS and ARTS/MELLLA

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
7. Scram Discharge Volume Water Level—High					
a. Level Transmitter	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 66 gallons
	5[a]	2	H	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 66 gallons
b. Float Switch	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 62 gallons
	5[a]	2	H	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 62 gallons
8. Turbine Stop Valve—Closure	≥ 30% RTP 26	4	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 7% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure—Low	≥ 30% RTP	2	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≥ 460 psig
10. Reactor Mode Switch— Shutdown Position	1,2	2	G	SR 3.3.1.1.14 SR 3.3.1.1.15	NA
	5[a]	2	H	SR 3.3.1.1.14 SR 3.3.1.1.15	NA
11. Manual Scram	1,2	2	G	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
	5[a]	2	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA

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

Retype to reflect PRNMS and ARTS/MELLLA

3.3 INSTRUMENTATION

3.3.2.2 Feedwater - Main Turbine High Water Level Trip Instrumentation

LCO 3.3.2.2 Three channels of feedwater - main turbine high water level trip instrumentation shall be OPERABLE.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

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ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One feedwater - main turbine high water level trip channel inoperable.	A.1 Place channel in trip.	7 days
B. Two or more feedwater - main turbine high water level trip channels inoperable.	B.1 Restore feedwater - main turbine high water level trip capability.	2 hours
C. Required Action and associated Completion Time of Conditions A or B not met.	C.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

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

OR

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 ~~≥ 30~~% RTP. ≥ 26

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable. AND MCPR limit for inoperable EOC-RPT not made applicable.	A.1 Restore channel to OPERABLE status.	72 hours
	OR	
	A.2 -----NOTE----- Not applicable if inoperable channel is the result of an inoperable breaker. ----- Place channel in trip.	72 hours
	OR	

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	72 hours
B. One or more Functions with EOC-RPT trip capability not maintained. AND MCPR limit for inoperable EOC-RPT not made applicable.	B.1 Restore EOC-RPT trip capability. OR B.2 Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	2 hours 2 hours
C. Required Action and associated Completion Time not met.	C.1 Remove the associated recirculation pump from service. OR C.2 Reduce THERMAL POWER to < 30% RTP.	4 hours 4 hours

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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	-----NOTE----- A test of all required contacts does not have to be performed. ---------- Perform CHANNEL FUNCTIONAL TEST.	 92 days
SR 3.3.4.1.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: TSV—Closure: ≤7% closed; and TCV Fast Closure, Trip Oil Pressure—Low: ≥ 460 psig.	24 months
SR 3.3.4.1.3	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	24 months
SR 3.3.4.1.4	Verify TSV—Closure and TCV Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ 30% RTP.	24 months

(continued)

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Table 3.3.6.1-1 (page 1 of 6)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
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 3.3.6.1.4 SR 3.3.6.1.5	≥ -136 inches
b. Main Steam Line Pressure - Low	1	2	E	SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 841 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 3.3.6.1.4 SR 3.3.6.1.5	179 psid ≤ ~~124 psig~~
d. Condenser Vacuum - Low	1 $2^{(a)}, 3^{(a)}$	2	D	SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5	≥ 8.8 inches Hg vacuum
e. Reactor Building Main Steam Tunnel Temperature - High	1,2,3	2	D	SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5	≤ 184°F
f. Manual Initiation	1,2,3	1	G	SR 3.3.6.1.5	NA

(continued)

(a) With any main turbine stop valve not closed.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.2.1 -----NOTES----- 1. Not required to be completed until 4 hours after associated recirculation loop is in operation. 2. Not required to be completed until 24 hours after > 25% RTP. ----- Verify at least two of the following criteria (a, b, or c) are satisfied for each operating recirculation loop: a. Recirculation loop drive flow versus Recirculation Pump speed 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.	23 24 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 Safety/Relief Valves (S/RVs)

LCO 3.4.3 The safety function of ~~12~~ 14 S/RVs shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.4.10.3	----------NOTE---------- Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump start. -------------------- Verify the difference between the bottom head coolant temperature and the reactor pressure vessel (RPV) coolant temperature is ≤ 145°F.	Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.10.4	----------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.	Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.10.5	----------NOTE---------- Only required to be met in single loop operation when: a. THERMAL POWER ≤ 80% RTP; or b. The operating recirculation loop flow ≤ 21,320 gpm. -------------------- Verify the difference between the bottom head coolant temperature and the RPV coolant temperature is ≤ 145°F.	27 Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.4.10.6	-----NOTE----- Only required to be met in single loop operation when the idle recirculation loop is not isolated from the RPV, and: a. THERMAL POWER ≤ 30% RTP; or b. The operating recirculation loop flow ≤ 21,320 gpm. ---------- Verify the difference between the reactor coolant temperature in the recirculation loop not in operation and the RPV coolant temperature is ≤ 50°F.	27 Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow.
SR 3.4.10.7	-----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.	30 minutes
SR 3.4.10.8	-----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.	30 minutes

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.10	Remove and test the explosive squib from each shear isolation valve of the TIP System.	24 months on a STAGGERED TEST BASIS
SR 3.6.1.3.11	-------NOTES------- Only required to be met in MODES 1, 2, and 3. ------- Verify the combined leakage rate for all secondary containment bypass leakage paths is ≤ 9 scfh when pressurized to ≥ P_a.	In accordance with the Primary Containment Leakage Rate Testing Program.
SR 3.6.1.3.12	-------NOTES------- Only required to be met in MODES 1, 2, and 3. ------- Verify leakage rate through each MSIV is ≤ 100 scfh and ≤300 scfh for the combined leakage including the leakage from the MS Line Drains, when the MSIVs are tested at ≥ 22.5 psig or P_a and the MS Line Drains are tested at P_a.	In accordance with the Primary Containment Leakage Rate Testing Program.

(continued)

24.3

3.7 PLANT SYSTEMS

3.7.1 Residual Heat Removal Service Water (RHRSW) System and the Ultimate Heat Sink (UHS)

LCO 3.7.1 Two RHRSW subsystems and the UHS shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

-----NOTE-----
Enter applicable Conditions and Required Actions of LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System-Hot Shutdown," for RHR shutdown cooling made inoperable by RHRSW System.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -----NOTE----- Separate Condition entry is allowed for each valve. --- One valve in Table 3.7.1-1 inoperable. OR One valve in Table 3.7.1-2 inoperable. OR ~~One valve in Table 3.7.1-2 and the same return loop valve in Table 3.7.1-1 inoperable.~~ Any combination of valves in Table 3.7.1-1, Table 3.7.1-2, or Table 3.7.1-3 in the same return loop inoperable. OR One valve in Table 3.7.1-3 inoperable.	A.1 Declare the associated RHRSW subsystems inoperable AND A.2 Restore the inoperable valve(s) to OPERABLE status.	Immediately 8 hours from the discovery of an inoperable RHRSW subsystem in the opposite loop from the inoperable valve(s) AND 72 hours

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	Verify the water level is greater than or equal to 678 feet 1 inch above Mean Sea Level.	12 hours
SR 3.7.1.2	Verify the average water temperature of the UHS is: a. ------------------------------NOTE------------------------------ Only applicable with both units in MODE 1 or 2, or with either unit in MODE 3 for less than twelve (12) hours. --- ≤ 85°F; or b. ------------------------------NOTE------------------------------ Only applicable when either unit has been in MODE 3 for at least twelve (12) hours but not more than twenty-four (24) hours. --- ≤ 87°F; or c. ------------------------------NOTE------------------------------ Only applicable when either unit has been in MODE 3 for at least twenty-four (24) hours. --- ≤ 88°F	24 hours
SR 3.7.1.3	Verify each RHRSW 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 3.7.1.4~~	~~Verify that valves HV-01222A and B (the spray loop bypass valves) close upon receipt of a closing signal.~~	~~92 days~~
~~SR 3.7.1.5~~	~~Verify that valves HV-01224A1 and B1 (the large loop spray array valves) open on receipt of an opening signal.~~	~~92 days~~

Insert 3.7-3A

Insert 3.7-3A

SR 3.7.1.4	Verify that valves HV-01222A and B (the spray array bypass valves) close upon receipt of a closing signal and open upon receipt of an opening signal.	92 days
SR 3.7.1.5	Verify that valves HV-01224A1 and B1 (the large spray array valves) close upon receipt of a closing signal and open upon receipt of an opening signal.	92 days
SR 3.7.1.6	Verify that valves HV-01224A2 and B2 (the small spray array valves) close upon receipt of a closing signal and open upon receipt of an opening signal.	92 days
SR 3.7.1.7	Verify that valves 012287A and 012287B (the spray array bypass manual valves) are capable of being opened and closed.	92 days

TABLE 3.7.1-1 ~~(PAGE 1 OF 1)~~

Ultimate Heat Sink Spray ~~Cooling Large~~ Array Valves

VALVE NUMBER	VALVE DESCRIPTION
HV-01224A1	Loop A large spray array valve
HV-01224B1	Loop B large spray array valve
HV-01224A2	Loop A small spray array valve
HV-01224B2	Loop B small spray array valve

TABLE 3.7.1-2

Array

Ultimate Heat Sink Spray Bypass Valves

VALVE NUMBER	VALVE DESCRIPTION
HV-01222A	Loop A spray array bypass valve
HV-01222B	Loop B spray array bypass valve

Insert 3.7-36A

< new page >

Insert 3.7-3bA

TABLE 3.7.1-3 Ultimate Heat Sink Spray Array Bypass Manual Valves	
VALVE NUMBER	VALVE DESCRIPTION
012287A	Loop A spray array bypass manual valve
012287B	Loop B spray array bypass manual valve

3.7 PLANT SYSTEMS

3.7.6 Main Turbine Bypass System

LCO 3.7.6 The Main Turbine Bypass System shall be OPERABLE.

<u>OR</u>

Apply the following limits for an inoperable Main Turbine Bypass System as specified in the COLR:

a. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and

b. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)."

APPLICABILITY: THERMAL POWER ≥ 25% RTP. 23

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Main Turbine Bypass System inoperable. <u>AND</u> Requirements of LCO 3.2.2 not met. <u>OR</u> Requirements of LCO 3.2.3 not met.	A.1 Satisfy the requirements of the LCO or restore Main Turbine Bypass System to OPERABLE status.	2 hours 23
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

3.7 PLANT SYSTEMS

3.7.8 Main Turbine Pressure Regulation System

LCO 3.7.8 Both Main Turbine Pressure Regulators shall be OPERABLE.

OR

Apply the following limits for an inoperable Main Turbine Pressure Regulator as specified in the COLR:

a. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and

b. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)."

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Main Turbine Pressure Regulator inoperable. AND Requirements of LCO 3.2.2 not met. OR Requirements of LCO 3.2.3 not met.	A.1 Satisfy the requirements of the LCO or restore Main Turbine Pressure Regulator to OPERABLE status.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.8.1	Verify that both Main Turbine Pressure Regulators are each capable of controlling main steam pressure.	92 days
SR 3.7.8.2	Perform a system functional test.	24 months

5.5 Programs and Manuals

5.5.11 Safety Function Determination Program (SFDP) (continued)

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.12 Primary Containment Leakage Rate Testing Program

A program shall be established, implemented, and maintained to comply with the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program", dated September 1995, as modified by the following exception:

a. NEI 94-01-1995, Section 9.2.3: The first Type A test performed after the May 4, 1992 Type A test shall be performed no later than May 3, 2007.

The peak calculated containment internal pressure for the design basis loss of coolant accident, Pa, is ~~45.0~~ psig. 48.6

The maximum allowable primary containment leakage rate, ~~La, at Pa, shall~~ be 1% of the primary containment air weight per day.

Leakage Rate Acceptance Criteria are:

a. Primary Containment leakage rate acceptance criterion is ≤ 1.0 La. During each unit startup following testing in accordance with this program, the leakage rate acceptance criteria are ≤ 0.60 La for Type B and Type C tests and ≤ 0.75 La for Type A tests:

b. Air lock testing acceptance criteria are:

   1) Overall air lock leakage rate is ≤ 0.05 La when tested at ≥ Pa.

   2) For each door, leakage rate is ≤ 5 scfh when pressurized to ≥ 10 psig.

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Primary Containment Leakage Rate Testing Program.

The provisions of SR 3.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

5.6 Reporting Requirements (continued)

5.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the main steam safety/relief valves, shall be submitted on a monthly basis no later than the 15th of each month following the calendar month covered by the report.

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. The Average Planar Linear Heat Generation Rate for Specification 3.2.1;
2. The Minimum Critical Power Ratio for Specification 3.2.2;
3. The Linear Heat Generation Rate for Specification 3.2.3;
4. The Average Power Range Monitor (APRM) Gain and Setpoints for Specification 3.2.4; and
5. The Shutdown Margin for Specification 3.1.1.
6. The OPRM setpoints for Specification 3.3.1.3.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC.

~~When an initial assumed power level of 102 percent of rated power is specified in a previously approved method, this refers to the power level associated with the design basis analyses, or 3510 MWt. The power level of 3510 MWt is 100.6% of the rated thermal power level of 3489 MWt. The RTP of 3489 MWt may only be used when feedwater flow measurement (used as input to the reactor thermal power measurement) is provided by the Leading Edge Flow Meter (LEFM✔™) as described in the LEFM✔™ Topical Report and supplement referenced below. When feedwater flow measurements from the LEFM✔™ system are not available, the core thermal power level may not exceed the originally approved RTP of 3441 MWt, but the value of 3510 MWt~~

(continued)

5.6 Reporting Requirements

5.6.5 COLR (continued)

~~(102% of 3441 MWt), remains the initial power level for the bounding licensing analysis.~~

~~Future revisions of approved analytical methods listed in this Technical Specification that are currently referenced to 102% of rated thermal power (3510 MWt) shall include reference that the licensed RTP is actually 3489 MWt. The revisions shall document that the licensing analysis performed at 3510 MWt bounds operation at the RTP of 3489 MWt so long as the LEFM✓™ system is used as the feedwater flow measurement input into the core thermal power calculation.~~

The approved analytical methods are described in the following documents, the approved version(s) of which are specified in the COLR.

1. PL-NF-90-001-A, "Application of Reactor Analysis Methods for BWR Design and Analysis."
2. XN-NF-80-19(P)(A), "Exxon Nuclear Methodology for Boiling Water Reactors," Exxon Nuclear Company, Inc.
3. XN-NF-85-67(P)(A), "Generic Mechanical Design for Exxon Nuclear Jet Pump BWR Reload Fuel, "Exxon Nuclear Company, Inc.
4. ANF-524(P)(A), "Advanced Nuclear Fuels Corporation Critical Power Methodology for Boiling Water Reactors"
5. NE-092-001A, "Licensing Topical Report for Power Uprate With Increased Core Flow," Pennsylvania Power & Light Company.
6. ANF-89-98(P)(A), "Generic Mechanical Design Criteria for BWR Fuel Designs," Advanced Nuclear Fuels Corporation.

(continued)

5.6 Reporting Requirements

5.6.5 COLR (continued)

9. XN-NF-84-105(P)(A), 'XCOBRA-T: A Computer Code for BWR Transient Thermal-Hydraulic Core Analysis," Exxon Nuclear Company.

10. ANF-524(P)(A), "ANF Critical Power Methodology for Boiling Water Reactors," Advanced Nuclear Fuels Corporation.

11. ANF-913(P)(A), "COTRANSA2: A Computer Program for Boiling Water Reactor Transient Analyses," Advanced Nuclear Fuels Corporation.

12. ANF-1358(P)(A), "The Loss of Feedwater Heating Transient in Boiling Water Reactors,' Advanced Nuclear Fuels Corporation.

13. EMF-2209(P)(A), "SPCB Critical Power Correlation,' Siemens Power Corporation.

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

15. NE-092-001 A, -Licensing Topical Report for Power Uprate With Increased Core Flow," Pennsylvania Power & Light Company.

~~16. Caldon, Inc., "TOPICAL REPORT: Improving Thermal Power Accuracy and Plant Safety while Increasing Operating Power Level Using the LEFTM@M System," Engineering Report - 80P~~

~~17. Caldon, Inc., "Supplement to Topical Report ER-80P: Basis for a Power Uprate with the LEFMV41 or LEFM CheckPlus™' System," Engineering Report ER-160P.~~

16 ~~18.~~ NEDO-32465-A, UBWROG Reactor Core Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications."

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.

(continued)

Retype to Reflect U1C15 Changes

Operating License Changes
Unit 2
(Mark-up)

(3) PPL Susquehanna, LLC, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed neutron sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) PPL Susquehanna, LLC, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, possess, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) PPL Susquehanna, LLC, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR 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

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PPL Susquehanna, LLC is authorized to operate the facility at reactor core power levels not in excess of ~~3489~~ megawatts thermal (100% power) in accordance with the conditions specified herein and in Attachment 1 to this license. The preoperational test, startup tests and other items identified in Attachment 1 to this license shall be completed as specified. Attachment 1 is hereby incorporated into this license.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 202, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. PPL Susquehanna, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

For Surveillance Requirements (SRs) that are new in Amendment 151 to Facility Operating License No. NPF-22, the first performance is due at the end of the first surveillance interval that begins at implementation of Amendment 151. For SRs that existed prior to Amendment 151, including SRs with modified acceptance criteria and

Technical Specifications Changes
Unit 2
(Mark-up)

1.1 Definitions (continued)

RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of ~~3489~~ MWt. 3952
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from when the monitored parameter exceeds its RPS trip setpoint at the channel sensor until de-energization of the scram pilot valve solenoids. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.
SHUTDOWN MARGIN (SDM)	SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming that: a. The reactor is xenon free; b. The moderator temperature is 68°F; and c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.
STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.
TURBINE BYPASS SYSTEM RESPONSE TIME	The TURBINE BYPASS SYSTEM RESPONSE TIME consists of the time from when the turbine bypass control unit generates a turbine bypass valve flow signal

(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 psig or core flow < 10 million lbm/hr:

THERMAL POWER shall be ≤ 25% RTP. 23

2.1.1.2 With the reactor steam dome pressure ≥ 785 psig and core flow ≥ 10 million lbm/hr:

MCPR shall be ≥ 1.09 for two recirculation loop operation or ≥ 1.10 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.

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 sodium pentaborate in solution IS NOT ~~< 13.6 weight percent but~~ within limits of Figure 3.1.7-1.	A.1 Restore concentration of sodium pentaborate in solution to within limits ~~> 13.6 weight percent.~~ OF FIGURE 3.1.7-1	~~72~~ 8 hours ~~AND~~ ~~10 days from discovery of failure to meet the LCO~~
B. One SLC subsystem inoperable for reasons other than Condition A.	B.1 Restore SLC subsystem to OPERABLE status.	7 days ~~AND~~ ~~10 days from discovery of failure to meet the LCO~~
C. Two SLC subsystems inoperable for reasons other than Condition A.	C.1 Restore one SLC subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	12 hours

WITHIN THE LIMITS OF FIGURE 3.1.7-1

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.1.7.1	Verify available volume of sodium pentaborate solution is ~~≥ 4587 gallons.~~	24 hours
SR 3.1.7.2	Verify temperature of sodium pentaborate solution is within the limits of Figure 3.1.7-2.	24 hours
SR 3.1.7.3	Verify temperature of pump suction piping is within the limits of Figure 3.1.7-2.	24 hours
SR 3.1.7.4	Verify continuity of explosive charge.	31 days
SR 3.1.7.5	Verify the concentration of sodium pentaborate in solution is ~~≥ 13.6 weight percent and~~ within the limits of Figure 3.1.7-1.	31 days AND Once within 24 hours after water or sodium pentaborate is added to solution AND Once within 24 hours after solution temperature is restored within the limits of Figure 3.1.7-2

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.7.6	Verify each SLC subsystem manual and power operated 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~~ 40.0 gpm at a discharge pressure ≥ ~~1395~~ 1250 psig.	In accordance with the Inservice Testing Program
SR 3.1.7.8	Verify flow through one SLC subsystem pump into reactor pressure vessel.	24 months on a STAGGERED TEST BASIS
SR 3.1.7.9	Verify all heat traced piping between storage tank and pump suction is unblocked.	24 months AND Once within 24 hours after solution temperature is restored within the limits of Figure 3.1.7-2

INSERT 3.1-22A

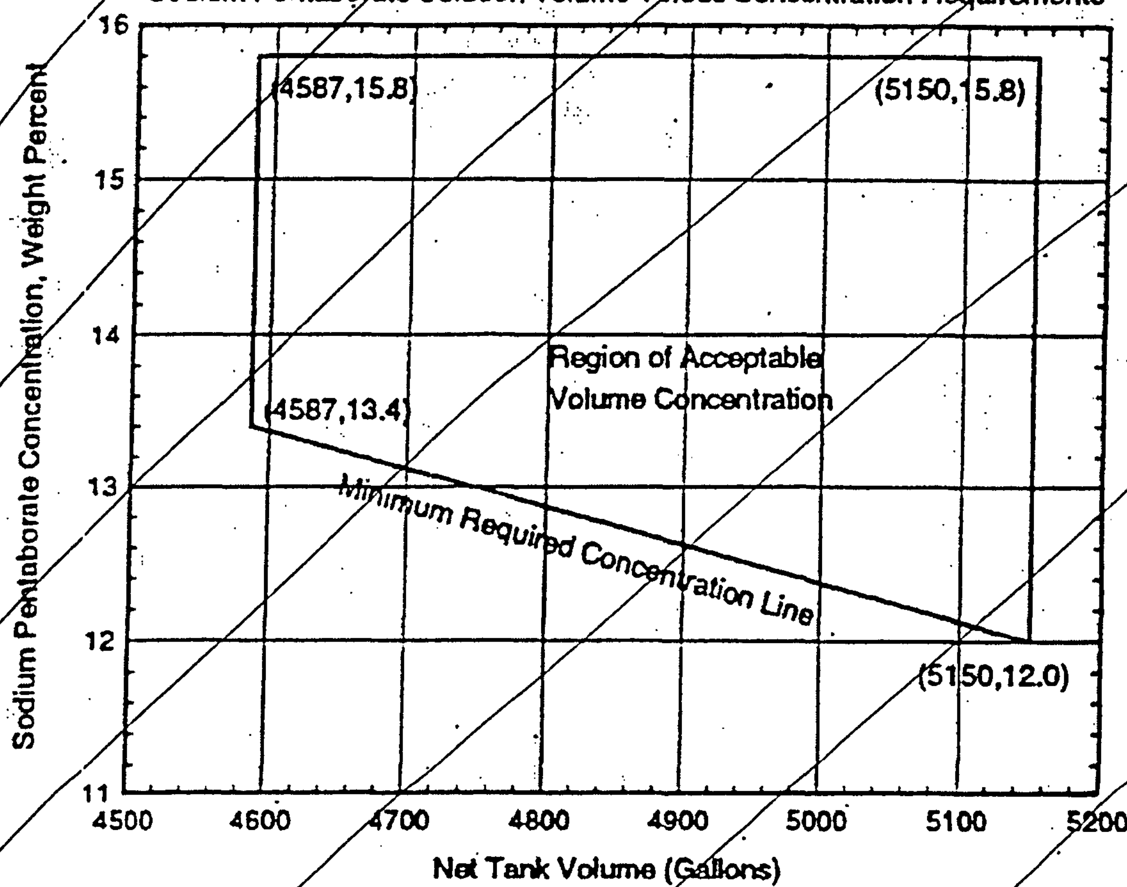
Insert 3.1-22A

	SURVEILLANCE	FREQUENCY
SR 3.1.7.10	Verify sodium pentaborate enrichment is ≥ 88 atom percent B-10.	Prior to addition to SLC tank.

INSERT 3.1-23A

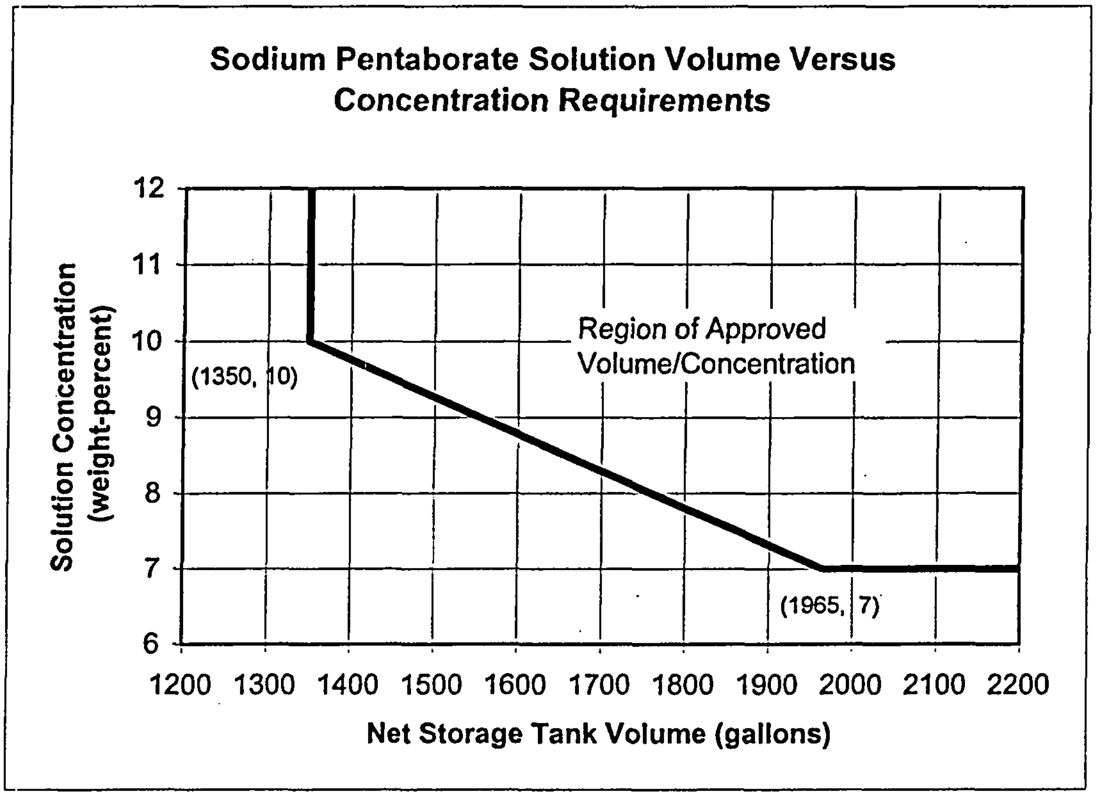
FIGURE 3.1.7-1

Sodium Pentaborate Solution Volume Versus Concentration Requirements



Insert 3.1-23A

FIGURE 3.1.7-1



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.

APPLICABILITY: THERMAL POWER ≥ 25% RTP. 23

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.	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 24 hours after ≥25% RTP 23 __AND__ 24 hours thereafter __AND__ Prior to exceeding 50% RTP

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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% RTP. 23

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% 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 24 hours after ≥25% RTP 23 <u>AND</u> 24 hours thereafter <u>AND</u> Prior to exceeding 50% RTP
SR 3.2.2.2	Determine the MCPR limits.	Once within 72 hours after each completion of SRs in 3.1.4

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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.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

23

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.	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 24 hours after ≥ 25% RTP 23 <u>AND</u> 24 hours thereafter <u>AND</u> Prior to exceeding 50% RTP 44

ACTIONS (continued)

CONDITION		REQUIRED ACTION		COMPLETION TIME
C.	One or more Functions with RPS trip capability not maintained.	C.1	Restore RPS trip capability.	1 hour
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 channels.	Immediately
E.	As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < 30% RTP. 26	4 hours
F.	As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G.	As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours
H.	As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

(continued)

Retype to reflect PBNMS and ARTS/MELLLA

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. As required by Required Action D.1 and referenced in Table 3.3.1.1-1	I.1 Initiate alternate method to detect and suppress thermal hydraulic instability oscillations.	12 hours
	<u>AND</u>	
	I.2 Restore require channels to OPERABLE.	120 days
J. Required Action and associated Completion Time of Condition I not met.	J.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

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Retype to reflect PRNMS and ARTS/MELLLA

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	Perform CHANNEL CHECK.	24 hours
SR 3.3.1.1.3	------------------------------NOTE------------------------------ Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. -- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP while operating at ≥ 25% RTP.	23 7 days
SR 3.3.1.1.4	------------------------------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

(continued)

Retype to reflect PRNMS and ARTS/MELLLA

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.6	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to fully withdrawing SRMs from the core.
SR 3.3.1.1.7	-------------------NOTE------------------- Only required to be met during entry into MODE 2 from MODE 1. --- Verify the IRM and APRM channels overlap.	7 days
SR 3.3.1.1.8	Calibrate the local power range monitors.	2,000 ~~1000~~ MWD/MT average core exposure
SR 3.3.1.1.9	-------------------NOTE------------------- A test of all required contacts does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.1.1.10	Perform CHANNEL CALIBRATION.	92 days

(continued)

~~Retype to reflect~~
PRN~~MS~~ and AR~~TS~~/MELLLA

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.11	-----NOTES----- 1. Neutron detectors are excluded. 2. For Function 1.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL CALIBRATION.	184 days
SR 3.3.1.1.12	-----NOTES----- 1. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2.. 2. For Functions 2.b and 2.f, the CHANNEL FUNCTIONAL TEST includes the recirculation flow input processing, excluding the flow transmitters. ---------- Perform CHANNEL FUNCTIONAL TEST.	184 days
SR 3.3.1.1.13	Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.1.14	Perform CHANNEL FUNCTIONAL TEST.	24 months
SR 3.3.1.1.15	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.16	Verify Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ ~~30~~% RTP.	24 months

(continued)

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Retype to reflect PRNMS and ARTS/MELLLA

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.17	------NOTES------ 1. Neutron detectors are excluded. 2. For Function 5 "n" equals 4 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. 3. For Function 2.e, "n" equals 8 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. Testing of APRM and OPRM outputs shall alternate. ------------ Verify the RPS RESPONSE TIME is within limits.	24 months on a STAGGERED TEST BASIS
SR 3.3.1.1.18	------NOTES------ 1. Neutron detectors are excluded. 2. For Functions 2.b and 2.f, the recirculation flow transmitters that feed the APRMs are included. ------------ Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.1.19	Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ 30% and recirculation drive flow is ≤ value equivalent to the core flow value defined in the COLR.	24 months 25
SR 3.3.1.1.20	Adjust recirculation drive flow to conform to reactor core flow.	24 months

~~Retype to reflect~~ PRNMS and ARTS/MELLLA

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	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.11 SR 3.3.1.1.15	≤ 122/125 divisions of full scale
	5[(a)]	3	H	SR 3.3.1.1.1 SR 3.3.1.1.5 SR 3.3.1.1.11 SR 3.3.1.1.15	≤ 122/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.4 SR 3.3.1.1.15	NA
	5[(a)]	3	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
2. Average Power Range Monitors					
a. Neutron Flux—High (Setdown)	2	3[(c)]	G	SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.18	≤ 20% RTP
b. Simulated *Thermal* Power—High	1	3[(c)]	F	SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.18 SR 3.3.1.1.20	0.55 W + 60.7 ≤ 0.62 W + 64.2% RTP[(b)] and ≤ 115.5% RTP

(continued)

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

(b) 0.62(W - ΔW) + 64.2% RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

(c) Each APRM channel provides ~~inputs to both~~ trip systems.

0.55(W − ΔW) + 60.7

~~Retype~~ to ~~reflect~~ PRNMS and ARTS/MELLLA

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
2. Average Power Range Monitors (continued)					
c. Neutron Flux—High	1	$3^{(c)}$	F	SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.8 SR 3.3.1.1.12 SR 3.3.1.1.18	≤ 120% RTP
d. Inop	1,2	$3^{(c)}$	G	SR 3.3.1.1.12	NA
e. 2-Out-Of-4 Voter	1, 2	2	G	SR 3.3.1.2 SR 3.3.1.12 SR 3.3.1.15 SR 3.3.1.17	NA
f. OPRM Trip	≥ 25% RTP 23	$3^{(c)}$	I	SR 3.3.1.2 SR 3.3.1.8 SR 3.3.1.12 SR 3.3.1.18 SR 3.3.1.19 SR 3.3.1.20	(d)
3. Reactor Vessel Steam Dome Pressure—High	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.15	≤ 1093 psig
4. Reactor Vessel Water Level—Low, Level 3	1,2	2	G	SR 3.3.1.1.1 SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.15	≥ 11.5 inches
5. Main Steam Isolation Valve—Closure	1	8	F	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ 11% closed
6. Drywell Pressure—High	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.10 SR 3.3.1.1.15	≤ 1.88 psig

(continued)

(c) Each APRM channel provides inputs to both trip systems.

(d) See COLR for OPRM period based detection algorithm (PBDA) setpoint limits.

Retype to reflect PRNMS and ARTS/MELLLA

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
7. Scram Discharge Volume Water Level—High					
a. Level Transmitter	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 66 gallons
	5[(a)]	2	H	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 66 gallons
b. Float Switch	1,2	2	G	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 62 gallons
	5[(a)]	2	H	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15	≤ 62 gallons
8. Turbine Stop Valve—Closure	≥ 30% RTP 26	4	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≤ 7% closed
9. Turbine Control Valve Fast Closure, Trip Oil Pressure—Low	≥ 30% RTP	2	E	SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.15 SR 3.3.1.1.16 SR 3.3.1.1.17	≥ 460 psig
10. Reactor Mode Switch—Shutdown Position	1,2	2	G	SR 3.3.1.1.14 SR 3.3.1.1.15	NA
	5[(a)]	2	H	SR 3.3.1.1.14 SR 3.3.1.1.15	NA
11. Manual Scram	1,2	2	G	SR 3.3.1.1.5 SR 3.3.1.1.15	NA
	5[(a)]	2	H	SR 3.3.1.1.5 SR 3.3.1.1.15	NA

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

Retype to reflect PRNMS and ARTS/MELLLA

3.3 INSTRUMENTATION

3.3.2.2 Feedwater - Main Turbine High Water Level Trip Instrumentation

LCO 3.3.2.2 Three channels of feedwater - main turbine high water level trip instrumentation shall be OPERABLE.

APPLICABILITY: THERMAL POWER ≥ 25% RTP.

23

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One feedwater - main turbine high water level trip channel inoperable.	A.1	Place channel in trip.	7 days
B. Two or more feedwater - main turbine high water level trip channels inoperable.	B.1	Restore feedwater - main turbine high water level trip capability.	2 hours
C. Required Action and associated Completion Time of Conditions A or B not met.	C.1	Reduce THERMAL POWER to < 25% RTP.	4 hours

23

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

OR

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 > ~~30~~% RTP.

26

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more channels inoperable. AND MCPR limit for inoperable EOC-RPT not made applicable.	A.1	Restore channel to OPERABLE status.	72 hours
	OR		
	A.2	-----NOTE----- Not applicable if inoperable channel is the result of an inoperable breaker. --------------- Place channel in trip.	 72 hours
	OR		

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.3	Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	72 hours
B. One or more Functions with EOC-RPT trip capability not maintained. AND MCPR limit for inoperable EOC-RPT not made applicable	B.1	Restore EOC-RPT trip capability.	2 hours
	OR		
	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 from service.	4 hours
	OR		
	C.2	Reduce THERMAL POWER to < 30% RTP.	4 hours

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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	--- A test of all required contacts does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	 92 days
SR 3.3.4.1.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: TSV—Closure: ≤ 7% closed; and TCV Fast Closure, Trip Oil Pressure—Low: ≥ 460 psig.	24 months
SR 3.3.4.1.3	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	24 months
SR 3.3.4.1.4	Verify TSV—Closure and TCV Fast Closure, Trip Oil Pressure—Low Functions are not bypassed when THERMAL POWER is ≥ 30% RTP.	24 months

(continued)

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Table 3.3.6.1-1 (page 1 of 6)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
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 3.3.6.1.4 SR 3.3.6.1.5	≥ -136 inches
b. Main Steam Line Pressure - Low	1	2	E	SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 841 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 3.3.6.1.4 SR 3.3.6.1.5	179 psid ≤ ~~121 psig~~
d. Condenser Vacuum - Low	1 $2^{(a)}, 3^{(a)}$	2	D	SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5	≥ 8.8 inches Hg vacuum
e. Reactor Building Main Steam Tunnel Temperature - High	1,2,3	2	D	SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5	≤ 184°F
f. Manual Initiation	1,2,3	1	G	SR 3.3.6.1.5	NA

(continued)

(a) With any main turbine stop valve not closed.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.2.1 -------------------------NOTES------------------------- 1. Not required to be completed until 4 hours after associated recirculation loop is in operation. 2. Not required to be completed until 24 hours after ≥ 25% RTP. --- Verify at least two of the following criteria (a, b, or c) are satisfied for each operating recirculation loop: a. Recirculation loop drive flow versus Recirculation Pump speed 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.	23 24 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 Safety/Relief Valves (S/RVs)

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LCO 3.4.3 *The safety function of* ~~12~~ *S/RVs shall be* OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.10.3	----------NOTE---------- Only required to be met in MODES 1, 2, 3, and 4 during recirculation pump start. -------------------- Verify the difference between the bottom head coolant temperature and the reactor pressure vessel (RPV) coolant temperature is ≤ 145°F.	Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.10.4	----------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.	Once within 15 minutes prior to each startup of a recirculation pump
SR 3.4.10.5	----------NOTE---------- Only required to be met in single loop operation when: a. THERMAL POWER ≤ 80% RTP; or b. The operating recirculation loop flow ≤ 21,320 gpm. -------------------- Verify the difference between the bottom head coolant temperature and the RPV coolant temperature is ≤ 145°F.	27 Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.4.10.6	---NOTE--- Only required to be met in single loop operation when the idle recirculation loop is not isolated from the RPV, and: a. THERMAL POWER ≤ 30% RTP; or b. The operating recirculation loop flow ≤ 21,320 gpm. ------ Verify the difference between the reactor coolant temperature in the recirculation loop not in operation and the RPV coolant temperature is ≤ 50°F.	27 Once within 15 minutes prior to an increase in THERMAL POWER or an increase in loop flow.
SR 3.4.10.7	---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.	30 minutes
SR 3.4.10.8	---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.	30 minutes

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.6.1.3.11	----------NOTES---------- Only required to be met in MODES 1, 2, and 3. ---------- Verify the combined leakage rate for all secondary containment bypass leakage paths is $\leq$ 9 scfh when pressurized to $\geq P_a$.	In accordance with the Primary Containment Leakage Rate Testing Program.
SR 3.6.1.3.12	----------NOTES---------- Only required to be met in MODES 1, 2, and 3. ---------- Verify leakage rate through each MSIV is $\leq$100 scfh and $\leq$ 300 scfh for the combined leakage including the leakage from the MS Line Drains when the MSIVs are tested at $\geq$ ~~22.5~~ psig or P_a and the MS Line Drains are tested at P_a.	In accordance with the Primary Containment Leakage Rate Testing Program.

(continued)

24.3

3.7 PLANT SYSTEMS

3.7.1 Residual Heat Removal Service Water (RHRSW) System and the Ultimate Heat Sink (UHS)

LCO 3.7.1 Two RHRSW subsystems and the UHS shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTE---

Enter applicable Conditions and Required Actions of LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System-Hot Shutdown," for RHR shutdown cooling made inoperable by RHRSW System.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------NOTE------------ Separate Condition entry is allowed for each valve. ---------------------------- One valve in Table 3.7.1-1 inoperable. OR One valve in Table 3.7.1-2 inoperable. OR One valve in Table 3.7.1-3 inoperable. OR ~~One valve in Table 3.7.1-2 and the same return loop valve in Table 3.7.1-1 inoperable.~~ Any combination of valves in Table 3.7.1-1, Table 3.7.1-2, or Table 3.7.1-3 in the same return loop inoperable.	A.1 Declare the associated RHRSW subsystems inoperable. AND A.2 Restore the inoperable valve(s) to OPERABLE status.	Immediately 8 hours from the discovery of an inoperable RHRSW subsystem in the opposite loop from the inoperable valve(s) AND 72 hours

(continued)

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.7.1.1	Verify the water level is greater than or equal to 678 feet 1 inch above Mean Sea Level.	12 hours
SR 3.7.1.2	Verify the average water temperature of the UHS is: a. ----------NOTE---------- Only applicable with both units in MODE 1 or 2, or with either unit in MODE 3 for less than twelve (12) hours. -------------------- ≤ 85°F; or b. ----------NOTE---------- Only applicable when either unit has been in MODE 3 for at least twelve (12) hours but not more than twenty-four (24) hours. -------------------- ≤ 87°F; or c. ----------NOTE---------- Only applicable when either unit has been in MODE 3 for at least twenty-four (24) hours. -------------------- ≤ 88°F.	24 hours
SR 3.7.1.3	Verify each RHRSW 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 3.7.1.4~~	~~Verify that valves HV-01222A and B (the spray loop bypass valves) close upon receipt of a closing signal.~~	~~92 days~~
~~SR 3.7.1.5~~	~~Verify that valves HV-01224A1 and B1 (the large loop spray array valves) open upon receipt of an opening signal.~~	~~92 days~~

Insert 3.7-3A

Insert 3.7-3A

SR 3.7.1.4	Verify that valves HV-01222A and B (the spray array bypass valves) close upon receipt of a closing signal and open upon receipt of an opening signal.	92 days
SR 3.7.1.5	Verify that valves HV-01224A1 and B1 (the large spray array valves) close upon receipt of a closing signal and open upon receipt of an opening signal.	92 days
SR 3.7.1.6	Verify that valves HV-01224A2 and B2 (the small spray array valves) close upon receipt of a closing signal and open upon receipt of an opening signal.	92 days
SR 3.7.1.7	Verify that valves 012287A and 012287B (the spray array bypass manual valves) are capable of being opened and closed.	92 days

TABLE 3.7.1-1 ~~(PAGE 1 OF 1)~~

Ultimate Heat Sink Spray ~~Cooling Large~~ Array Valves

VALVE NUMBER	VALVE DESCRIPTION
HV-01224A1	Loop A large spray array valve
HV-01224B1	Loop B large spray array valve
HV-01224A2	Loop A Small spray array valve
HV-01224B2	Loop B Small spray array valve

TABLE 3.7.1-2 (PAGE 1 OF 1)

Ultimate Heat Sink Spray Array Bypass Valves

VALVE NUMBER	VALVE DESCRIPTION
HV-01222A	Loop A spray array bypass valve
HV-01222B	Loop B spray array bypass valve

Insert 3.7-3bA

<New Page>

Insert 3.7-3bA

TABLE 3.7.1-3 Ultimate Heat Sink Spray Array Bypass Manual Valves	
VALVE NUMBER	VALVE DESCRIPTION
012287A	Loop A spray array bypass manual valve
012287B	Loop B spray array bypass manual valve

3.7 PLANT SYSTEMS

3.7.6 Main Turbine Bypass System

LCO 3.7.6 The Main Turbine Bypass System shall be OPERABLE.

<u>OR</u>

Apply the following limits for an inoperable Main Turbine Bypass System as specified in the COLR:

a. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and

b. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)."

APPLICABILITY: THERMAL POWER ≥ 25% RTP. 23

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Main Turbine Bypass System inoperable. <u>AND</u> Requirements of LCO 3.2.2 not met. <u>OR</u> Requirements of LCO 3.2.3 not met.	A.1 Satisfy the requirements of the LCO or restore Main Turbine Bypass System to OPERABLE status.	2 hours 23
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 25% RTP.	4 hours

3.7 PLANT SYSTEMS

3.7.8 Main Turbine Pressure Regulation System

LCO 3.7.8 Both Main Turbine Pressure Regulators shall be OPERABLE.

OR

Apply the following limits for an inoperable Main Turbine Pressure Regulator as specified in the COLR:

a. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and

b. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)."

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Main Turbine Pressure Regulator inoperable. AND Requirements of LCO 3.2.2 not met. OR Requirements of LCO 3.2.3 not met.	A.1 Satisfy the requirements of the LCO or restore Main Turbine Pressure Regulator to OPERABLE status.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.8.1	Verify that both Main Turbine Pressure Regulators are each capable of controlling main steam pressure.	92 days
SR 3.7.8.2	Perform a system functional test.	24 months

5.5 Programs and Manuals

5.5.11 Safety Function Determination Program (SFDP) (continued)

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered. When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.12 Primary Containment Leakage Rate Testing Program

A program shall be established, implemented, and maintained to comply with the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak-Test Program," dated September 1995, as modified by the following exception:

a. NEI 94-01-1995, Section 9.2.3: The first Type A test performed after the October 31, 1992 Type A test shall be performed no later than October 30, 2007.

The peak calculated containment internal pressure for the design basis loss of coolant accident, Pa, is ~~15.0~~ psig. 48.6

The maximum allowable primary containment leakage rate, La, ~~at Pa, shall~~ be 1% of the primary containment air weight per day.

Leakage Rate Acceptance Criteria are:

a. Primary Containment leakage rate acceptance criterion is ≤ 1.0 La. During each unit startup following testing in accordance with this program, the leakage rate acceptance criteria are ≤ 0.60 La for Type B and Type C tests and ≤ 0.75 La for Type A tests;

b. Air lock testing acceptance criteria are:

   1) Overall air lock leakage rate is ≤ 0.05 La when tested at ≥ Pa,

   2) For each door, leakage rate is ≤ 5 scfh when pressurized to ≥ 10 psig.

The provisions of SR 3.0.2 do not apply to the test frequencies specified in the Primary Containment Leakage Rate Testing Program.

The provisions of SR 3.0.3 are applicable to the Primary Containment Leakage Rate Testing Program.

5.6 Reporting Requirements (continued)

5.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the main steam safety/relief valves, shall be submitted on a monthly basis no later than the 15th of each month following the calendar month covered by the report.

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1. The Average Planar Linear Heat Generation Rate for Specification 3.2.1;

2. The Minimum Critical Power Ratio for Specification 3.2.2;

3. The Linear Heat Generation Rate for Specification 3.2.3;

4 The Average Power Range Monitor (APRM) Gain and Setpoints for Specification 3.2.4; and

5. The Shutdown Margin for Specification 3.1.1.

6. The OPRM setpoints for Specification 3.3.1.3.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC.

~~When an initial assumed power level of 102 percent of rated power is specified in a previously approved method, this refers to the power level associated with the design basis analyses, or 3510 MWt. The power level of 3510 MWt is 100.6% of the rated thermal power level of 3489 MWt. The RTP of 3489 MWt may only be used when feedwater flow measurement (used as input to the reactor thermal power measurement) is provided by the Leading Edge Flow Meter (LEFM✓™) as described in the LEFM✓™ Topical Report and supplement referenced below. When feedwater flow measurements from the LEFM✓™ system are not available, the~~

(continued)

5.6.5 COLR (continued)

core thermal power level may not exceed the originally approved RTP of 3441 MWt, but the value of 3510 MWt (102% of 3441 MWt) remains the initial power level for the bounding licensing analysis.

Future revisions of approved analytical methods listed in this Technical Specification that are currently referenced to 102% of rated thermal power (3510 MWt) shall include reference that the licensed RTP is actually 3489 MWt. The revisions shall document that the licensing analysis performed at 3510 MWt bounds operation at the RTP of 3489 MWt so long as the LEFM✓™ system is used as the feedwater flow measurement input into the core thermal power calculation.

The approved analytical methods are described in the following documents, the approved version(s) of which are specified in the COLR.

1. XN-NF-81-58(P)(A), "RODEX2 Fuel Rod Thermal-Mechanical Response Evaluation Model," Exxon Nuclear Company.
2. XN-NF-85-67(P)(A), "Generic Mechanical Design for Exxon Nuclear Jet pump BWR Reload Fuel," Exxon Nuclear Company.
3. EMF-85-74(P)(A), "RODEX2A (BWR) Fuel Rod Thermal-Mechanical Evaluation Model," Siemens Power Corporation.
4. ANF-89-98(P)(A), "Generic Mechanical Design Criteria for BWR Fuel Designs," Advanced Nuclear Fuels Corporation.
5. XN-NF-80-19(P)(A), "Exxon Nuclear Methodology for Boiling Water Reactors," Exxon Nuclear Company.
6. EMF-2158(P)(A), "Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation of CASMO-4/MICROBURN-B2," Siemens Power Corporation.
7. EMF-2361(P)(A), "EXEM BWR-2000 ECCS Evaluation Model," Framatome ANP.
8. EMF-2292(P)(A), "ATRIUM™-10: Appendix K Spray Heat Transfer Coefficients," Siemens Power Corporation.
9. XN-NF-84-105(P)(A), "XCOBRA-T: A Computer Code for BWR Transient Thermal-Hydraulic Core Analysis," Exxon Nuclear Company.

(continued)

5.6 Reporting Requirements

5.6.5 COLR (continued)

10. ANF-524(P)(A), "ANF Critical Power Methodology for Boiling Water Reactors," Advanced Nuclear Fuels Corporation.

11. ANF-913(P)(A), "COTRANSA2: A Computer Program for Boiling Water Reactor Transient Analyses," Advanced Nuclear Fuels Corporation.

12. ANF-1358(P)(A), "The Loss of Feedwater Heating Transient in Boiling Water Reactors," Advanced Nuclear Fuels Corporation.

13. EMF-2209(P)(A), "SPCB Critical Power Correlation," Siemens Power Corporation.

14. EMF-1997(P)(A), "ANFB-10 Critical Power Correlation", Siemens Power Corporation.

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

16. NE-092-001A, "Licensing Topical Report for Power Uprate With Increased Core Flow," Pennsylvania Power & Light Company.

17. ~~Caldon, Inc., "TOPICAL REPORT: Improving Thermal Power Accuracy and Plant Safety while Increasing Operating Power Level Using the LEFM√™ System," Engineering Report - 80P.~~

18. ~~Caldon, Inc., "Supplement to Topical Report ER-80P: Basis for a Power Uprate with the LEFM√™ or LEFM CheckPlus™ System," Engineering Report ER-160P.~~

17 ~~19.~~ NEDO-32465-A, "BWROG Reactor Core Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications."

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.

continued

Attachment 2 to PLA-6002

Proposed Technical Specifications Bases Changes

(Mark-up)

Technical Specifications Bases Changes
Unit 1
(Mark-up)

APPLICABLE SAFETY ANALYSES

2.1.1.1 Fuel Cladding Integrity (continued)

FANP

For the ~~SPC~~ ATRIUM-10 design, the minimum bundle flow is > 28 x 10^3 lb/hr. For the ATRIUM-10 fuel design, the coolant minimum bundle flow and maximum area are such that the mass flux is always > .25 x 10^6 lb/hr-ft^2. Full scale critical power test data taken from various SPC and GE fuel designs at pressures ~~from~~ 14.7 psia to 1400 psia indicate the fuel assembly ~~critical~~ power at 0.25 x 10^6 lb/hr-ft^2 is approximately 3.35 MWt. At 25% ~~RTP, a~~ bundle power of approximately 3.35 MWt ~~corresponds~~ to a bundle ~~radial peaking~~ factor of approximately ~~2.0~~, which is significantly higher than the expected peaking factor. Thus, a THERMAL POWER limit of 25% RTP for reactor pressures < 785 psig ~~is~~ conservative.

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2.8

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and for conditions of lesser power would remain conservative.

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 in the critical power correlation. References 2, 4, and 5 describe the methodology used in determining the MCPR SL.

The ANFB-10 critical power correlation is based on a significant body of practical test data. As long as the core pressure and flow are within the range of validity of the correlations (refer to Section B.2.1.1.1), 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 inherent accuracy of the ANFB-10 correlation provide a reasonable degree of assurance that during sustained operation at the MCPR SL there would be no transition boiling in the core.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the residual heat removal shutdown cooling piping and in the recirculation loop piping. This quantity of borated solution is the amount that is above the pump suction shutoff level in the boron solution storage tank. No credit is taken for the portion of the tank volume that cannot be injected. The minimum concentration of 13.6 weight percent ensures compliance with the requirements of 10 CFR 50.62 (Ref. 1).

The SLC System satisfies the requirements of the NRC Policy Statement (Ref. 3) because operating experience and probabilistic risk assessments have shown the SLC System to be important to public health and safety. Thus, it is retained in the Technical Specifications.

LCO

The OPERABILITY of the SLC System provides backup capability for reactivity control independent of normal reactivity control provisions provided by the control rods. The OPERABILITY of the SLC System is based on the conditions of the borated solution in the storage tank and the availability of a flow path to the RPV, including the OPERABILITY of the pumps and valves. Two SLC subsystems are required to be OPERABLE; each contains an OPERABLE pump, an explosive valve, and associated piping, valves, and instruments and controls to ensure an OPERABLE flow path.

APPLICABILITY

In MODES 1 and 2, shutdown capability is required. In MODES 3 and 4, control rods are not able to be withdrawn (except as permitted by LCO 3.10.3 and LCO 3.10.4) since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate controls to ensure that the reactor remains subcritical. In MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Demonstration of adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") ensures that the reactor will not become critical. Therefore, the SLC System is not required to be OPERABLE when only a single control rod can be withdrawn.

(continued)

INSERT B 3.1-41A

BASES

ACTIONS

A.1

~~If the boron solution concentration is less than the required limits for compliance with 10 CFR 50.62 (Ref. 1) (≥ 13.6 weight percent) but greater than the concentration required for cold shutdown (original licensing basis), the concentration must be restored to within limits > 13.6 weight percent in 72 hours. It is not necessary under these conditions to enter Condition C for both SLC subsystems inoperable since they are capable of performing their original design basis function. Because of the low probability of an event and the fact that 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.~~

~~The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of concentration out of limits or inoperable SLC subsystems during any single continuous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, an SLC subsystem is inoperable and that subsystem is subsequently returned to OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total duration of 10 days (7 days in Condition B, followed by 3 days in Condition A), since initial failure of the LCO, to restore the SLC System. Then an SLC subsystem could be found inoperable again, and concentration could be restored to within limits. This could continue indefinitely.~~

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock," resulting in establishing the "time zero" at the time the LCO was initially not met instead of at the time Condition A was entered. The 10 day Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.~~

B.1

If one SLC subsystem is inoperable for reasons other than Condition A, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystem is adequate to perform the

(continued)

Insert B 3.1- 41A

A-1

If the boron solution concentration is not within the limits in Figure 3.1.7-1, the operability of both SLC subsystems is impacted and the concentration must be restored to within limits within 8 hours. The allowed Completion Time of 8 hours is considered acceptable given the low probability of an event occurring concurrent with the failure of the control rods to shut down the reactor.

BASES

ACTIONS

B.1 (continued)

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 an event occurring concurrent with the failure of the Control Rod Drive (CRD) System to shut down the plant.

~~The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of concentration out of limits or inoperable SLC subsystems during any single continuous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, concentration is out of limits, and is subsequently returned to within limits, the LCO may already have been not met for up to 3 days. This situation could lead to a total duration of 10 days (3 days in Condition A, followed by 7 days in Condition B), since initial failure of the LCO, to restore the SLC System. Then concentration could be found out of limits again, and the SLC subsystem could be restored to OPERABLE. This could continue indefinitely.~~

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock," resulting in establishing the "time zero" at the time the LCO was initially not met instead of at the time Condition B was entered. The 10 day Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.~~

C.1

If both SLC subsystems are inoperable for reasons other than Condition A, at least one subsystem must be restored to OPERABLE status within 8 hours. The allowed Completion Time of 8 hours is considered acceptable given the low probability of an event occurring concurrent with the failure of the control rods to shut down the reactor.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.7

1250 40.0

Demonstrating that each SLC System pump develops a flow rate ≥ ~~41.2~~ gpm at a discharge pressure ≥ ~~1395~~ psig without actuating the pump's relief valve ensures that pump performance has not degraded during the fuel cycle. Testing at ~~1395~~ psig assures that the functional capability of the SLC system meets the ATWS Rule (10 CFR 50.62) (Ref. 1) requirements. 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

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. The pump and explosive valve tested should be alternated such that both complete flow paths are tested every 48 months at alternating 24 month intervals. The Surveillance may be performed in separate steps to prevent injecting solution 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 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

Demonstrating that all heat traced piping between the boron solution storage tank and the suction inlet to the injection

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.8 and SR 3.1.7.9 (continued)

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. This test can be performed by any series of overlapping or total flow path test so that the entire flow path is included. The 24 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 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 or the heat trace was not properly energized and building temperature was below the temperature at which the SLC solution would precipitate out, SR 3.1.7.9 must be performed once within 24 hours after the piping temperature is restored to within the limits of Figure 3.1.7-2.

REFERENCES

1. 10 CFR 50.62.
2. FSAR, Section 9.3.5.
3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

INSERT B 3.1-46A

Insert B3.1-46A

SR3.1.7.10

Enriched sodium pentaborate solution is made by mixing granular, enriched sodium pentaborate with water. Verification of the actual B-10 enrichment must be performed prior to addition to the SLC tank in order to ensure that the proper B-10 atom percentage is being used. This verification may be based on independent isotopic analysis or a manufacturer certificate of compliance.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SPC LOCA analyses consider the delay in Low Pressure Coolant Injection (LPCI) availability when the unit is operating in the Suppression Pool Cooling Mode. The delay in LPCI availability is due to the time required to realign valves from the Suppression Pool Cooling Mode to the LPCI mode. The results of the analyses demonstrate that the PCTs are within the 10 CFR 50.46 limit.

Finally, the SPC LOCA analyses were performed for Single-Loop Operation. The results of the SPC analysis for ATRIUM™-10 fuel shows that an APLHGR limit which is 0.8 times the two-loop APLHGR limit meets the 10 CFR 50.46 acceptance criteria, and that the PCT is less than the limiting two-loop PCT.

The APLHGR satisfies Criterion 2 of the NRC Policy Statement (Ref. 10).

LCO

The APLHGR limits specified in the COLR are the result of the DBA analyses.

APPLICABILITY

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The APLHGR limits are primarily derived from LOCA 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. At THERMAL POWER levels ≤ 25% RTP, the reactor is operating with substantial margin to the APLHGR limits; thus, this LCO is not required.

ACTIONS

A.1

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

(continued)

BASES

ACTIONS (continued)

B.1

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

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SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

23 44

APLHGRs are required to be initially calculated within 24 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. Additionally, APLHGRs must be calculated prior to exceeding 50% RTP unless performed in the previous 24 hours. APLHGRs 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 during normal operation. The 24 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels and because the APLHGRs must be calculated prior to exceeding 50% RTP.

REFERENCES

1. Not used.
2. Not used.
3. ANF-91-048(P)(A), "Advanced Nuclear Fuels Corporation Methodology for Boiling Water Reactors EXEM BWR Evaluation Model," January 1993.
4. ANF-CC-33(P)(A) Supplement 2, "HUXY: A Generalized Multirod Heatup Code with 10CFR50 Appendix K Heatup Option," January 1991.
5. XN-CC-33(P)(A) Revision 1, "HUXY: A Generalized Multirod Heatup Code with 10CFR50 Appendix K Heatup Option Users Manual," November 1975.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

state to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency. These analyses may also consider other combinations of plant conditions (i.e., control rod scram speed, bypass valve performance, EOC-RPT, cycle exposure, etc.). Flow dependent MCPR limits are determined by analysis of slow flow runout transients using the methodology of Reference 2.

The MCPR satisfies Criterion 2 of the NRC Policy Statement (Ref. 10).

LCO

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the flow dependent MCPR and power dependent MCPR limits.

APPLICABILITY

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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 minimum 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. 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% RTP. This trend is expected to

(continued)

BASES

APPLICABILITY (continued)

continue to the 5% to 15% power range when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor provides rapid scram initiation for any significant power increase transient, which effectively ~~eliminates any~~ MCPR compliance concern. Therefore, at THERMAL POWER levels < 25% RTP, the reactor is operating with substantial margin to the MCPR limits and this LCO is not required.

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ACTIONS

A.1

If any MCPR is outside the required limits, 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 limits 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 limits and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the MCPR out of specification.

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B.1

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

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

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The MCPR is required to ~~be~~ initially calculated within 24 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. Additionally, MCPR must be calculated prior to exceeding 50% RTP unless performed in the previous 24 hours. MCPR is compared to the specified limits in the

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(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1 (continued)

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 24 hour allowance after THERMAL POWER ≥ ~~25~~ 23 % RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels and because the MCPR must be calculated prior to exceeding 50% RTP.

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SR 3.2.2.2

Because the transient analysis takes credit for conservatism in the scram time performance, it must be demonstrated that the specific scram time is consistent with those used in the transient analysis. SR 3.2.2.2 determines the scram time fraction which is a measure of the actual scram time compared with the assumed scram time. The COLR contains a table of scram time fractions based on the LCO 3.1.4 "Control Rod Scram Times" and the realistic scram times used in the transient analysis. The MCPR operating limit is then determined based on an interpolation between the applicable limits for scram times of LCO 3.1.4,"Control Rod Scram Times" and realistic scram time analyses using the scram time fraction. The scram time fraction and corresponding MCPR operating limit must be determined once within 72 hours after each set of scram time tests required by SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3 and SR 3.1.4.4 because the effective scram times may change during the cycle. The 72 hour Completion Time is acceptable due to the relatively minor changes in the scram time fraction expected during the fuel cycle.

REFERENCES

1. NUREG-0562, June 1979.

2. PL-NF-90-001-A, "Application of Reactor Analysis Methods for BWR Design and Analysis," July 1992, Supplement 1-A, August 1995, Supplement 2-A, July 1996, and Supplement 3-A, March 2001.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	Protection Against Power Transients (PAPT), defined in Reference 4 provides the acceptance criteria for LHGRs calculated in evaluation of the AOOs. The LHGR satisfies Criterion 2 of the NRC Policy Statement (Ref. 7).
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 23	The LHGR limits are derived from fuel design analysis that is limiting at high power level conditions. At core thermal power levels < 25% RTP, the reactor is operating with a substantial margin to the LHGR limits and, therefore, the Specification is only required when the reactor is operating at ≥ 25% RTP.
ACTIONS	<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 limits such that the plant is operating within analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the LHGR(s) to within its limits and is acceptable based on the low probability of a transient or Design Basis Accident occurring simultaneously with the LHGR out of specification.

B.1

23

If the LHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER is 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.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

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The LHGR is required to be initially calculated within 24 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. *Additionally, LHGRs must be calculated prior to exceeding 50% RTP unless performed in the previous 24 hours.* The LHGR 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 slow changes in power distribution during normal operation. The 24 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at lower power levels and because the LHGRs must be calculated prior to exceeding 50% RTP.

REFERENCES

1. FSAR, Section 4.
2. FSAR, Section 5.
3. NUREG-0800, Section II.A.2(g), Revision 2, July 1981.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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.

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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.

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

The Average Power Range Monitor Neutron Flux - High (Setdown) Function must be OPERABLE during MODE 2 when control rods may be withdrawn since the potential for criticality exists. In MODE 1, the Average Power Range Monitor Neutron Flux - High Function provides protection against reactivity transients and the RWM protects against control rod withdrawal error events.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.f. Oscillation Power Range Monitor (OPRM) Trip

The OPRM Trip Function provides compliance with GDC 10, "Reactor Design," and GDC 12, "Suppression of Reactor Power Oscillations" thereby providing protection from exceeding the fuel MCPR safety limit (SL) due to anticipated thermal-hydraulic power oscillations.

References 17, 18 and 19 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm (confirmation count and cell amplitude), the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Trip Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Trip Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

The OPRM Trip Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into "cells" for evaluation by the OPRM algorithms. 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. Three of the four channels are required to be OPERABLE.

The OPRM Trip is automatically enabled (bypass removed) when THERMAL POWER is ≥ ~~30%~~ 25 RTP, as indicated by the APRM Simulated Thermal Power, and reactor core flow is ≤ the value defined in the COLR, as indicated by APRM measured recirculation drive flow. This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations are expected to occur. Reference 21 includes additional discussion of OPRM Trip enable region limits.

These setpoints, which are sometimes referred to as the "auto-bypass" setpoints, establish the boundaries of the OPRM Trip enabled region. The APRM Simulated Thermal Power auto-enable setpoint has 1% deadband while the drive flow setpoint has a 2% deadband. The deadband for these setpoints is established so that it increases the enabled region once the region is entered.

(continued)

Retyped to include PRNMS and ARTS/MELLLA

23 25

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

The OPRM Trip Function is required to be OPERABLE when the plant is at ≥25% RTP. The 25% RTP level is selected to provide margin in the unlikely event that a reactor power increase transient occurring without operator action while the plant is operating below 30% RTP causes a power increase to or beyond the 30% APRM Simulated Thermal Power OPRM Trip auto-enable setpoint. This OPERABILITY requirement assures that the OPRM Trip auto-enable function will be OPERABLE when required.

An APRM channel is also required to have a minimum number of OPRM cells OPERABLE for the Upscale Function 2.f to be OPERABLE. The OPRM cell operability requirements are documented in the Technical Requirements Manual, TRO 3.3.9, and are established as necessary to support the trip setpoint calculations performed in accordance with methodologies in Reference 19.

An OPRM Trip is issued from an APRM 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 OPRM Trip from that channel. An OPRM Trip is also issued from the channel if either the growth rate or amplitude based algorithms detect oscillatory changes in the neutron flux for one or more cells in that channel. (Note: To facilitate placing the OPRM Trip Function 2.f in one APRM channel in a "tripped" state, if necessary to satisfy a Required Action, the APRM equipment is conservatively designed to force an OPRM Trip output from the APRM channel if an APRM Inop condition occurs, such as when the APRM chassis keylock switch is placed in the Inop position.)

There are three "sets" of OPRM related setpoints or adjustment parameters: a) OPRM Trip auto-enable region setpoints for STP and drive flow; b) period based detection algorithm (PBDA) confirmation count and amplitude setpoints; and c) period based detection algorithm tuning parameters.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7.a, 7.b. Scram Discharge Volume Water Level - High (continued)

Four channels of each type of Scram Discharge Volume Water Level - High Function, with two channels of each type in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from these Functions on a valid signal. These Functions are required 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.

8. Turbine Stop Valve - Closure

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 Function is the primary scram signal for the turbine trip event analyzed in Reference 5. 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 signals are initiated from position switches located on each of the four TSVs. Two independent position switches are associated with each stop valve. One of the two switches 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 channels, each consisting of one position switch. The logic for the Turbine Stop Valve - Closure Function is such that three or more TSVs must be closed to produce a scram. This Function must be enabled at THERMAL POWER ≥ 30% RTP. This is accomplished automatically by pressure instruments sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this function non-conservatively, THERMAL POWER is derived from first stage pressure. The main turbine bypass valves must not cause the trip Function to be bypassed when THERMAL POWER is ≥ 30% RTP.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

8. Turbine Stop Valve - Closure (continued)

Eight channels (arranged in pairs) of Turbine Stop Valve - Closure 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 ≥ 30% RTP. This Function is not required when THERMAL POWER is < 30% RTP since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Neutron Flux—High Functions are adequate to maintain the necessary safety margins.

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9. 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 5. 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 electrohydraulic control (EHC) fluid pressure at each control valve. One pressure instrument is associated with each control valve, and the signal from each transmitter is assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER ≥ 30% RTP. This is accomplished automatically by pressure instruments sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this function non-conservatively, THERMAL POWER is derived from first stage pressure. The main turbine bypass valves must not cause the trip Function to be bypassed when THERMAL POWER is ≥ 30% RTP.

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

(continued)

Retyped to include PRNMS and ARTS/MELLLA

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

9. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low (continued)

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 ≥ 30% RTP. This Function is not required when THERMAL POWER is < 30% RTP, since the Reactor Vessel Steam Dome Pressure - High and the Average Power Range Monitor Neutron Flux - High Functions are adequate to maintain the necessary safety margins.

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10. Reactor Mode Switch - Shutdown Position

The Reactor Mode Switch - Shutdown Position Function provides signals, via the manual scram logic channels, to each of the four RPS logic channels, which 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 overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

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

There is no Allowable Value for this Function, since the channels are mechanically actuated based solely on reactor mode switch position.

Four channels of Reactor Mode Switch - Shutdown Position. Function, with two channels in each trip system, are available and required to be OPERABLE. The Reactor Mode Switch - Shutdown Position Function is required to be OPERABLE in MODES 1 and 2, and 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.

(continued)

Retyped to include PRNMS and ARTS/MELLLA

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.3

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 3.3.1.1.8.

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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, LHGR 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 inconsideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.1.4

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

As noted, SR 3.3.1.1.4 is not required to be performed when entering MODE 2 from MODE 1, since testing of the MODE 2 required IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

A Frequency of 7 days provides an acceptable level of system average unavailability over the Frequency interval and is based on reliability analysis (Ref. 9).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.6 and SR 3.3.1.1.7 (continued)

If overlap for a group of channels is not demonstrated (e.g., IRM/APRM overlap), the reason for the failure of the Surveillance should be determined and the appropriate channel(s) declared inoperable. Only those appropriate channels that are required in the current MODE or condition should be declared inoperable.

A Frequency of 7 days is reasonable based on engineering judgment and the reliability of the IRMs and APRMs.

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles that are either measured by the Traversing Incore Probe (TIP) System at all functional locations or calculated for TIP locations that are not functional. The methodology used to develop the power distribution limits considers the uncertainty for both measured and calculated local flux profiles. This methodology assumes that all the TIP locations are functional for the first LPRM calibration following a refueling outage, and a minimum of 25 functional TIP locations for subsequent LPRM calibrations. The calibrated LPRMs establish the relative local flux profile for appropriate representative input to the APRM System. The ~~1000~~ 2000 MWD/MT Frequency is based on operating experience with LPRM sensitivity changes.

SR 3.3.1.1.9 and SR 3.3.1.1.14

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

(continued)

Retyped to include PRNMS and ARTS/MELLLA

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.9 and SR 3.3.1.1.14 (continued)

intended function. The 92 day Frequency of SR 3.3.1.1.9 is based on the reliability analysis of Reference 9.

SR 3.3.1.1.9 is modified by a Note that provides a general exception to the definition of CHANNEL FUNCTIONAL TEST. This exception is necessary because the design of instrumentation does not facilitate functional testing of all required contacts of the relay which input into the combinational logic. (Reference 10) Performance of such a test could result in a plant transient or place the plant in an undo risk situation. Therefore, for this SR, the CHANNEL FUNCTIONAL TEST verifies acceptable response by verifying the change of state of the relay which inputs into the combinational logic. The required contacts not tested during the CHANNEL FUNCTIONAL TEST are tested under the LOGIC SYSTEM FUNCTIONAL TEST, SR 3.3.1.1.15. This is acceptable because operating experience shows that the contacts not tested during the CHANNEL FUNCTIONAL TEST normally pass the LOGIC SYSTEM FUNCTIONAL TEST, and the testing methodology minimizes the risk of unplanned transients.

The 24 month Frequency of SR 3.3.1.1.14 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 24 month Frequency.

SR 3.3.1.1.10, SR 3.3.1.1.11, SR 3.3.1.1.13 and SR 3.3.1.1.18

A CHANNEL CALIBRATION verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

Note 1 for SR 3.3.1.1.18 states that neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.3) and the ~~1000~~ 2000 MWD/MT LPRM

(continued)

Retyped to include ~~PRNMS~~ and ~~ARTS~~/MELLLA

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.15

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

The LOGIC SYSTEM FUNCTIONAL TEST for APRM Function 2.e simulates APRM and OPRM trip conditions at the 2-out-of-4 Voter channel inputs to check all combinations of two tripped inputs to the 2-out-of-4 logic in the voter channels and APRM related redundant RPS relays.

The 24 month Frequency is based on the need to perform portions of 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 24 month Frequency.

SR 3.3.1.1.16

This SR ensures that scrams initiated from the Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 30% RTP. This is performed by a Functional check that ensures the scram feature is not bypassed at ≥ 30% RTP. Because main turbine bypass flow can affect this function nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the opening of the main turbine bypass valves must not cause the trip Function to be bypassed when Thermal Power is ≥ 30% RTP.

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If any bypass channel's trip function is nonconservative (i.e., the Functions are bypassed at ≥ 30% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve—Closure 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 24 months is based on engineering judgment and reliability of the components.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.17 (continued)

After 8 cycles, the sequence repeats.

Each test of an OPRM or APRM output tests each of the redundant outputs from the 2-Out-Of-4 Voter channel for that Function and each of the corresponding relays in the RPS. Consequently, each of the RPS relays is tested every fourth cycle. The RPS relay testing frequency is twice the frequency justified by References 15 and 16.

SR 3.3.1.1.19

This surveillance involves confirming the OPRM Trip auto-enable setpoints. The auto-enable setpoint values are considered to be nominal values as discussed in Reference 21. This surveillance ensures that the OPRM Trip is enabled (not bypassed) for the correct values of APRM Simulated Thermal Power and recirculation drive flow. Other surveillances ensure that the APRM Simulated Thermal Power and recirculation drive flow properly correlate with THERMAL POWER (SR 3.3.1.1.2) and core flow (SR 3.3.1.1.20), respectively.

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If any auto-enable setpoint is nonconservative (i.e., the OPRM Trip is bypassed when APRM Simulated Thermal Power ≥ ~~30~~% and recirculation drive flow ≤ value equivalent to the core flow value defined in the COLR, then the affected channel is considered inoperable for the OPRM Trip Function. Alternatively, the OPRM Trip auto-enable setpoint(s) may be adjusted to place the channel in a conservative condition (not bypassed). If the OPRM Trip is placed in the not-bypassed condition, this SR is met and the channel is considered OPERABLE.

For purposes of this surveillance, consistent with Reference 21, the conversion from core flow values defined in the COLR to drive flow values used for this SR can be conservatively determined by a linear scaling assuming that 100% drive flow corresponds to 100 Mlb/hr core flow, with no adjustment made for expected deviations between core flow and drive flow below 100%.

The Frequency of 24 months is based on engineering judgment and reliability of the components.

(continued)

~~Retyped to include PRNMS and ARTS/MELLLA~~

B 3.3 INSTRUMENTATION

B 3.3.2.2 Feedwater – Main Turbine High Water Level Trip Instrumentation

BASES

BACKGROUND

The feedwater - main turbine high water level trip instrumentation is designed to detect a potential failure of the Feedwater Level Control System that causes excessive feedwater flow.

With excessive feedwater flow, the water level in the reactor vessel rises toward the high water level, Level 8 reference point, causing the trip of the three feedwater pump turbines and the main turbine.

Reactor Vessel Water Level—High, Level 8 signals are provided by level sensors 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 in the reactor vessel (variable leg). Three channels of Reactor Vessel Water Level—High, Level 8 instrumentation are provided as input to a two-out-of-three initiation logic that trips the three feedwater pump turbines and the main turbine. When the setpoint is exceeded, the channel sensor actuates, which then outputs a main feedwater and turbine trip signal to the trip logic.

A trip of the feedwater pump turbines limits further increase in reactor vessel water level by limiting further addition of feedwater to the reactor vessel. A trip of the main turbine and closure of the stop valves protects the turbine from damage due to water entering the turbine.

APPLICABLE SAFETY ANALYSES

The feedwater - main turbine high water level trip instrumentation is assumed to be capable of providing a turbine trip in the design basis transient analysis for a feedwater controller failure, maximum demand event (Ref. 1). The Level 8 trip indirectly initiates a reactor scram from the main turbine trip (above 30% RTP) and trips the feedwater pumps, thereby terminating the event. The reactor scram mitigates the reduction in MCPR.

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(continued)

BASES (continued)

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APPLICABILITY

The feedwater - main turbine high water level trip instrumentation is required to be OPERABLE at ≥25% RTP to ensure that the fuel cladding integrity Safety Limit is not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases of LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," sufficient margin to these limits exists below 25% RTP; therefore, the requirements are only necessary when operating at or above this power level.

ACTIONS

A Note has been provided to modify the ACTIONS related to feedwater - main turbine high water level trip 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 feedwater - main turbine high water level trip instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable feedwater - main turbine high water level trip instrumentation channel.

A.1

With one channel inoperable, the remaining two OPERABLE channels can provide the required trip signal. However, overall instrumentation reliability is reduced because a single failure in one of the remaining channels concurrent with feedwater controller failure, maximum demand event, may result in the instrumentation not being able to perform its intended function. Therefore, continued operation is only allowed for a limited time with one channel inoperable. If the inoperable channel cannot be restored to OPERABLE status within the Completion Time, the channel must be placed in the tripped condition per Required Action A.1. Placing the

(continued)

BASES

ACTIONS

B.1 (continued)

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 feedwater - main turbine high water level trip instrumentation occurring during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2 for Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1 23

With the required channels not restored to OPERABLE status or placed in trip, THERMAL POWER must be reduced to < 25% RTP within 4 hours. As discussed in the Applicability section of the Bases, operation below 25% RTP results in sufficient margin to the required limits, and the feedwater - main turbine high water level trip instrumentation is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The allowed Completion Time of 4 hours is based on operating experience to reduce THERMAL POWER to < 25% RTP from full power conditions in an orderly manner and without challenging plant systems.

If the failure only affects the trip function of a single main feed pump, an option is always available to remove the affected component from service and restore OPERABILITY. This is acceptable because removing the component from service performs the safety function.

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 feedwater - main turbine high water level trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status

(continued)

BASES

BACKGROUND (continued)

(2) The closing of two Turbine Stop Valves may or may not cause an RPT trip depending on which stop valves are closed.

(3) The closing of three or more Turbine Stop Valves will always yield an RPT trip.

If either trip system actuates, both recirculation pumps will trip. There are two RPT breakers in series per recirculation pump. One trip system trips one of the two RPT breakers for each recirculation pump, and the second trip system trips the other RPT breaker for each recirculation pump.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The TSV—Closure and the TCV Fast Closure, Trip Oil Pressure-Low Functions are designed to trip the recirculation pumps in the event of a turbine trip or generator load rejection to mitigate the neutron flux, heat flux, and 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 take credit for EOC-RPT, are summarized in References 2 and 3.

To mitigate pressurization transient effects, the EOC-RPT must trip the recirculation pumps after initiation of 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 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 < 30% RTP. 26

EOC-RPT instrumentation satisfies Criterion 3 of the NRC Policy Statement. (Ref. 4)

The OPERABILITY of the EOC-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.1.2. The actual setpoint is calibrated consistent with applicable

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Turbine Stop Valve—Closure

Closure of the TSVs and a main turbine trip result 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 TSV—Closure in anticipation of the transients that would result from closure of these valves. EOC-RPT decreases reactor power and aids the reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient. Closure of the TSVs is determined by measuring the position of each valve. There are two separate position switches associated with each stop valve, the signal from each switch being assigned to a separate trip channel. The logic for the TSV—Closure Function is such that two or more TSVs must be closed to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ 30% RTP. This is accomplished automatically by pressure instruments sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this function nonconservatively (THERMAL POWER is derived from first stage pressure), the main turbine bypass valves must not cause the trip Functions to be bypassed when thermal power is ≥ 30% 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 Allowable Value is selected to detect imminent TSV closure.

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This protection is required, consistent with the safety analysis assumptions, whenever THERMAL POWER is ≥ 30% RTP. Below 30% RTP, 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.

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Turbine Control Valve 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient.

Fast closure of the TCVs is determined by measuring the electrohydraulic control fluid pressure at each control valve. There is one pressure instrument associated with each control valve, and the signal from each instrument 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 instrument trips) to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ 30% RTP. This is accomplished automatically by pressure instruments sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this function nonconservatively (THERMAL POWER ~~is derived from~~ 26 first stage pressure) the main turbine bypass valves must not cause the trip Functions to be bypassed when thermal power is ≥ 30% RTP. Four channels of TCV Fast Closure, Trip Oil Pressure—Low, 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 TCV Fast Closure, Trip Oil Pressure—Low Allowable Value is selected high enough to detect imminent TCV fast closure.

≥ 26 26

This protection is required consistent with the ~~safety analysis~~ ~~whenever~~ THERMAL POWER is ~~≥ 30~~% RTP. Below ~~30% RTP, 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.

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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

capability when 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. This requires two channels of the Function in the same trip system, to each be OPERABLE or in trip, and the associated RPT breakers to be OPERABLE or in trip. Alternately, 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 time 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 for Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1 and C.2

26

With any Required Action and associated Completion Time not met, THERMAL POWER must be reduced to < 30% RTP within 4 hours. Alternately, the associated recirculation pump 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 < 30% RTP from full power conditions in an orderly manner and without challenging plant systems.

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. 4) assumption of the average

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.2 (continued)

The Frequency is based upon the assumption of an 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.4.1.3

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(s) would also be inoperable.

The 24 month Frequency is based on the need to perform portions of this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.4.1.4

This SR ensures that an EOC-RPT initiated from the TSV—Closure and TCV Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 30% RTP. This is performed by a Functional check that ensures the EOC-RPT Function is not bypassed. Because increasing the main turbine bypass flow can affect this function nonconservatively (THERMAL POWER is derived from first stage pressure) the main turbine bypass valves must not cause the trip Functions to be bypassed when thermal power is ≥ 30% RTP. If any functions are bypassed at ≥ 30% RTP, either due to open main turbine bypass valves or other reasons, the affected TSV—Closure 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 with the channel considered OPERABLE.

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(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.b. Main Steam Line Pressure—Low

Low MSL pressure indicates that there may be a problem with the turbine pressure regulation, which could result in a low reactor vessel water level condition and the RPV cooling down more than 100°F/hr if the pressure loss is allowed to continue. The Main Steam Line Pressure—Low Function is directly assumed in the analysis of the pressure regulator failure (Ref. 2). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hr) 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 psig, which results in a scram due to MSIV closure, thus reducing reactor power to < ~~25~~% RTP.) 23

The MSL low pressure signals are initiated from four instruments that are connected to the MSL header. The instruments are arranged such that, even though physically separated from each other, each instrument 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 Main Steam Line Pressure—Low trip will only occur after a 500 millisecond time delay to prevent any spurious isolations.

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).

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

drive flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, loop drive flow versus pump speed relationship must be verified.

Individual jet pumps in a recirculation loop normally 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 timely for detecting jet pump degradation and is consistent with the Surveillance Frequency for recirculation loop OPERABILITY verification.

This SR is modified by two Notes. If this SR has not been performed in the previous 24 hours at the time an idle recirculation loop is restored to service, Note 1 allows 4 hours after the idle recirculation loop is in operation before the SR must be completed because these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions and complete data collection and evaluation.

Note 2 allows deferring completion of this SR until 24 hours after THERMAL POWER is greater than 25% of RTP. During low flow conditions, jet pump noise approaches the threshold

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(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of S/RVs are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB). 14

The S/RVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. There are a total of 16 S/RVs of which any ~~12~~ are required to be OPERABLE. The S/RVs can actuate by either of two modes: the safety mode or the relief mode. In the safety mode (or spring mode of operation), the valve opens when steam pressure at the valve inlet overcomes the spring force holding the valve closed. This satisfies the Code requirement.

Each S/RV discharges steam through a discharge line to a point below the minimum water level in the suppression pool. Six S/RVs also serve as the Automatic Depressurization System (ADS) valves. The ADS requirements are specified in LCO 3.5.1, "ECCS—Operating."

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressurization 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. 1). For the purpose of the analyses, ~~12~~ of the 16 S/RVs are assumed to operate 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.

14

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. Reference 2 discusses additional events that are expected to actuate the S/RVs.

S/RVs satisfy Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

14

The safety function of ~~12~~ of the 16 S/RVs are required to be OPERABLE to satisfy the assumptions of the safety analysis (Refs. 1 and 2). The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety function).

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

Operation with fewer valves OPERABLE than specified, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded.

APPLICABILITY

In MODES 1, 2, and 3, all required S/RVs must be OPERABLE, since considerable energy may be in the reactor core and the limiting design basis transients are assumed to occur in these MODES. The S/RVs may be required to provide pressure relief to discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of dissipating the core heat.

In MODE 4 reactor pressure is low enough that the overpressure limit is unlikely to be approached by assumed

(continued)

BASES

APPLICABILITY (continued)	operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The S/RV function is not needed during these conditions.

ACTIONS

A.1 and A.2

With less than the minimum number of required S/RVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If the safety function of one or more required S/RVs is inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENT

SR 3.4.3.1

The Surveillance requires that the required S/RVs will open at the pressures assumed in the safety analysis of Reference 1. The demonstration of the S/RV safe lift settings must be performed during shutdown, since this is a bench test, to be done in accordance with the Inservice Testing Program. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures. The S/RV setpoint is ±3% of the nominal setpoint for OPERABILITY. Requirements for accelerated testing are established in accordance with the Inservice Test Program. Any of the 16 S/RVs, identified in this Surveillance Requirement, with their associated setpoints, can be designated as the ~~12~~ 14 ~~required S/RVs.~~ This maintains the assumptions in the overpressure analysis.

A Note is provided to allow up to two of the required ~~12~~ 14 S/RVs to be physically replaced with S/RVs with lower setpoints until the next refueling outage. This provides operational flexibility which maintains the assumptions in the over-pressure analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.10.3 and SR 3.4.10.4 (continued)

SR 3.4.10.3 has been modified by a Note that requires the Surveillance to be performed only in MODES 1, 2, 3, and 4. In MODE 5, the overall stress on limiting components is lower. Therefore, ΔT limits are not required. The Note also states the SR is only required to be met during a recirculation pump start-up, because this is when the stresses occur.

SR 3.4.10.5 and SR 3.4.10.6

Differential temperatures within the applicable limits ensure that thermal stresses resulting from increases in THERMAL POWER or recirculation loop flow during single recirculation loop operation will not exceed design allowances. Performing the Surveillance within 15 minutes before beginning such an increase in power or flow rate provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the change in operation.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.10.6 is to compare the temperatures of the operating recirculation loop and the idle loop.

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Plant specific startup test data has determined that the bottom head is not subject to temperature stratification at power levels >~~30~~% of RTP and with single loop flow rate ≥ 21,320 gpm (50% of rated loop flow). Therefore, SR 3.4.10.5 and SR 3.4.10.6 have been modified by a Note that requires the Surveillance to be met only under these conditions. The Note for SR 3.4.10.6 further limits the requirement for this Surveillance to exclude comparison of the idle loop temperature if the idle loop is isolated from the RPV since the water in the loop cannot be introduced into the remainder of the Reactor Coolant System.

SR 3.4.10.7, SR 3.4.10.8, and SR 3.4.10.9

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits during system heatup and cooldown. However, operations approaching MODE 4 from MODE 5 and in MODE 4 with RCS temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO limits.

(continued)

BASES (continued)

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 1.0% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 45 psig. 48.6

Primary containment satisfies Criterion 3 of the NRC Policy Statement. (Ref. 6)

LCO

Primary containment OPERABILITY is maintained by limiting leakage to ≤ 1.0 L_a, except prior to each startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time, applicable leakage limits must be met. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analyses.

Individual leakage rates specified for the primary containment air lock are addressed in LCO 3.6.1.2.

Leakage requirements for MSIVs and Secondary containment bypass are addressed in LCO 3.6.1.3.

(continued)

BASES (continued)

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 1.0% by weight of the containment air per 24 hours at the ~~calculated maximum peak~~ 48.6 containment pressure (P_a) of 45 psig (Ref. 3). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock.

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.

The primary containment air lock satisfies Criterion 3 of the NRC Policy Statement. (Ref. 4)

LCO

As part of the primary containment pressure boundary, 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 lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be opened at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry or exit from primary containment.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.10

The TIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired. The Frequency of 24 months on a STAGGERED TEST BASIS is considered adequate given the administrative controls on replacement charges and the frequent checks of circuit continuity (SR 3.6.1.3.4).

SR 3.6.1.3.11

This SR ensures that the leakage rate of secondary containment bypass leakage paths is less than the specified leakage rate. This provides assurance that the assumptions in the radiological evaluations of Reference 4 are met. The secondary containment leakage pathways and Frequency are defined by the Primary Containment Leakage Rate Testing Program. This SR simply imposes additional acceptance criteria. 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 MODES, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required.

SR 3.6.1.3.12

The analyses in References 1 and 4 are based on the specified leakage rate. Leakage through each MSIV must be ≤ 100 scfh for any one MSIV ~~or~~ and ≤ 300 scfh for total leakage through the MSIVs combined with the Main Steam Line Drain Isolation Valve, HPCI Steam Supply Isolation Valve and the RCIC Steam Supply Isolation Valve. The MSIVs can be tested at either ≥ Pt (~~22.5~~ 24.3 psig) or P_a (~~45~~ 48.6 psig). Main Steam Line Drain Isolation, HPCI and RCIC Steam Supply Line Isolation Valves, are tested at P_a (~~45~~ 48.6 psig). 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. The Frequency is required by the Primary Containment Leakage Rate Testing Program. If leakage from the MSIVs requires internal work on any MSIV, the leakage will be reduced for the affected MSIV to ≤ 11.5 scfh.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.13

53.46

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of Reference 2 are met. The acceptance criteria for the combined leakage of all hydrostatically tested lines is 3.3 gpm when tested at 1.1 P_a, (49.5 psig). The combined leakage rates must be demonstrated in accordance with the leakage rate test Frequency required by the Primary Containment Leakage Testing Program.

As noted in Table B 3.6.1.3-1, PCIVs associated with this SR are not Type C tested. Containment bypass leakage is prevented since the line terminates below the minimum water level in the Suppression Chamber. These valves are tested in accordance with the IST Program. Therefore, these valves leakage is not included as containment leakage.

This SR has been modified by a Note that states that 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 pressurized and primary containment is required. In some instances, the valves are required to be capable of automatically closing during MODES other than MODES 1, 2, and 3. However, specific leakage limits are not applicable in these other MODES or conditions.

REFERENCES

1. FSAR, Chapter 15.
2. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
3. 10 CFR 50, Appendix J, Option B.
4. FSAR, Section 6.2.
5. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.
6. Standard Review Plan 6.2.4, Rev. 1, September 1975
7. NEDO-32977-A, "Excess Flow Check Valve Testing Relaxation," June 2000.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operations to preserve the initial conditions assumed in the accident analysis for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES

Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs (Ref. 1). Among the inputs to the DBA is the initial primary containment internal pressure (Ref. 1). Analyses assume an initial containment pressure of -1.0 to 2.0 psig. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA containment internal pressure does not exceed the maximum allowable.

The maximum calculated containment pressure occurs during the reactor blowdown phase of the DBA, which assumes an instantaneous recirculation line break. The calculated peak containment pressure for this limiting event is 44.8 psig (Ref. 1). 48.6

The minimum containment pressure occurs during an inadvertent spray actuation. The calculated minimum drywell pressure for this limiting event is -4.72 psig. (Ref. 1)

Containment pressure satisfies Criterion 2 of the NRC Policy Statement. (Ref. 2)

LCO

In the event of a DBA, with an initial containment pressure -1.0 to 2.0 psig, the resultant peak containment accident pressure will be maintained below the containment design pressure. The containment pressure is defined to include both the drywell pressure and the suppression chamber pressure. (Ref. 1)

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.1 Residual Heat Removal Service Water (RHRSW) System and the Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The RHRSW System is designed to provide cooling water for the Residual Heat Removal (RHR) System heat exchangers, required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The RHRSW System is operated whenever the RHR heat exchangers are required to operate in the shutdown cooling mode or in the suppression pool cooling or spray mode of the RHR System.

The RHRSW System consists of two independent and redundant subsystems. Each subsystem is made up of a header, one pump, a suction source, valves, piping, heat exchanger, and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity to maintain safe shutdown conditions. The two subsystems are separated so that failure of one subsystem will not affect the OPERABILITY of the other subsystem. One Unit 1 RHRSW subsystem and the associated (same division) Unit 2 RHRSW subsystem constitute a single RHRSW loop. The two RHRSW pumps in a loop can each, independently, be aligned to either Unit's heat exchanger. The RHRSW System is designed with sufficient redundancy so that no single active component failure can prevent it from achieving its design function. The RHRSW System is described in the FSAR, Section 9.2.6, Reference 1.

Cooling water is pumped by the RHRSW pumps from the UHS through the tube side of the RHR heat exchangers. After removing heat from the RHRSW heat exchanger, the water is discharged to the spray pond (UHS) by way of the UHS return loops. The UHS return loops direct the return flow to a network of sprays that dissipate the heat to the atmosphere or directly to the UHS via a bypass ~~valve~~ header.

The system is initiated manually from the control room except for the spray array bypass manual valves that are operated locally in the event of a failure of the spray array bypass valves. The system can be started any time the LOCA signal is manually overridden or clears.

(continued)

BASES

BACKGROUND (continued)

The ultimate heat sink (UHS) system is composed of a 350,000 cubic foot spray pond and associated piping and spray risers. Each UHS return loop contains a bypass line, a large spray array and a small spray array. The purpose of the UHS is to provide both a suction source of water and a return path for the RHRSW and ESW systems. The function of the UHS is to provide water to the RHRSW and ESW systems at a temperature less than the 97°F design temperature of the RHRSW and ESW systems. UHS temperature is maintained less than the design temperature by introducing the hot return fluid from the RHRSW and ESW systems into the spray loops and relying on spray cooling to maintain temperature. The UHS is designed to supply the RHRSW and ESW systems with all the cooling capacity required during a combination LOCA/LOOP for thirty days without fluid addition. The UHS is described in the FSAR, Section 9.2.7 (Reference 1).

APPLICABLE SAFETY ANALYSES

The RHRSW System removes heat from the suppression pool to limit the suppression pool temperature and primary containment pressure following a LOCA. This ensures that the primary containment can perform its function of limiting the release of radioactive materials to the environment following a LOCA. The ability of the RHRSW System to support long term cooling of the reactor or primary containment is discussed in the FSAR, Chapters 6 and 15 (Refs. 2 and 3, respectively). These analyses explicitly assume that the RHRSW System will provide adequate cooling support to the equipment required for safe shutdown. These analyses include the evaluation of the long term primary containment response after a design basis LOCA.

The safety analyses for long term cooling were performed for various combinations of RHR System failures. ~~The worst case single failure that would affect the performance of the RHRSW System is any failure that would disable one UHS return loop. The failure of the spray array bypass valve to close results in the inability of one UHS return loop to perform its design function because failure of this valve to close results in inadequate spray nozzle pressures on the affected loop.~~ As discussed in the FSAR, Section 6.2.2 (Ref. 2) for these analyses, manual initiation of the OPERABLE RHRSW subsystem and the associated RHR System is assumed to occur 30 minutes after a DBA. In this case, the maximum suppression chamber water temperature and pressure are analyzed to be below the design temperature of 220°F and maximum allowable pressure of 53 psig.

(continued)

Insert 3.7-3A

BASES

APPLICABLE SAFETY ANALYSES (continued)

~~The failure of the large spray array valve to open on demand is of less consequence than the failure of the spray array bypass valve because the small spray array is still available. Two small spray arrays have the same capacity and can perform the same function as a single large spray array. Each small array can effectively discharge the output of one RHRSW subsystem and one ESW loop to the UHS. The small spray arrays do not meet the 10CFR50.36 criteria for inclusion into the Technical Specifications and are not included. As a result, no credit is taken for the existence of the small spray arrays.~~

The RHRSW System, together with the UHS, satisfy Criterion 3 of the NRC Policy Statement. (Ref. 4)

LCO

Two RHRSW subsystems are required to be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, assuming the worst case single active failure occurs coincident with the loss of offsite power.

An RHRSW subsystem is considered OPERABLE when:

a. One pump is OPERABLE; and

b. An OPERABLE flow path is capable of taking suction from the UHS and transferring the water to the RHR heat exchanger and returning it to the UHS at the assumed flow rate, and

c. An OPERABLE UHS.

The OPERABILITY of the UHS is based on having a minimum water level at the overflow weir of 678 feet 1 inch above mean sea level and a maximum water temperature of 85°F; unless either unit is in MODE 3. If a unit enters MODE 3, the time of entrance into this condition determines the appropriate maximum ultimate heat sink fluid temperature. If the earliest unit to enter MODE 3 has been in that condition for less than twelve (12) hours, the peak temperature to maintain OPERABILITY of the ultimate heat sink remains at 85°F. If either unit has been in MODE 3 for more than twelve (12) hours but less than twenty-four (24) hours, the OPERABILITY temperature of the ultimate heat sink becomes 87°F. If either unit has been in MODE 3 for twenty-four (24) hours or more, the OPERABILITY temperature of the ultimate heat sink becomes 88°F.

(continued)

<u>Insert B 3.7-3A</u>

The UHS design takes into account the cooling efficiency of the spray arrays and the evaporation losses during design basis environmental conditions. The spray array bypass header provides the flow path for the ESW and RHRSW system to keep the spray array headers from freezing. The small and/or large spray arrays are placed in service to dissipate heat returning from the plant. The UHS return header is comprised of the spray array bypass header, the large spray array, and the small spray array.

The spray array bypass header is capable of passing full flow from the RHRSW and ESW systems in each loop. The large spray array is capable of passing full flow from the RHRSW and ESW systems in each loop. The small spray array supports heat dissipation when low system flows are required.

Insert B 3.7-5A

BASES

ACTIONS (continued)

A.1

~~With one spray array bypass valve inoperable (that is, not capable of being closed on demand), or with one large spray array valve not capable of being opened, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the spray cooling function of the affected UHS return loop. As a result, the associated RHRSW subsystems must be declared inoperable.~~

A.2

Insert B 3.7-5B

~~With one spray array bypass valve or one large spray array valve inoperable, only one large spray array is available for effective spray cooling. Failure of either the spray bypass valve or the large spray array valve in the unaffected loop would result in insufficient spray cooling capacity.~~ The 72-hour completion time is based on the fact that, although adequate UHS spray loop capability exists during this time period, both units are affected and an additional single failure results in a system configuration that will not meet design basis accident requirements.

If an additional RHRSW subsystem on either Unit is inoperable, cooling capacity less than the minimum required for response to a design basis event would exist. Therefore, an 8-hour Completion Time is appropriate. The 8-hour Completion Time provides sufficient time to restore inoperable equipment and there is a low probability that a design basis event would occur during this period.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if one Unit 1 RHRSW subsystem is inoperable. Although designated and operated as a unitized system, the associated Unit 2 subsystem is directly connected to a common header, which can supply the associated RHR heat exchanger in either unit. The Unit 2 subsystems are considered capable of supporting Unit 1 RHRSW subsystem when the Unit 2 subsystem is OPERABLE and can provide the assumed flow to the Unit 1 heat exchanger. A Completion time of 72 hours, when one Unit 2 RHRSW subsystem is not capable of supporting the Unit 1 RHRSW subsystems, is allowed to restore the Unit 1 RHRSW subsystem to OPERABLE status. In this configuration, the remaining OPERABLE Unit 1 RHRSW subsystem is adequate to perform the RHRSW heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE RHRSW subsystem

(continued)

Insert B 3.7-5A

With one spray array loop bypass valve not capable of being closed on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the spray cooling function of the affected UHS return loop. As a result, the associated RHRSW subsystem must be declared inoperable.

With one spray array loop bypass valve not capable of being opened on demand, the associated Unit 1 and Unit 2 RHRSW subsystems and ESW subsystem are not provided a return path to the UHS. As a result, the associated RHRSW subsystems and ESW subsystem must be declared inoperable.

With one spray array bypass manual valve not capable of being closed, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the spray cooling function of the affected UHS return path if the spray array bypass valve fails to close. As a result, the associated RHRSW subsystems must be declared inoperable.

With one spray array bypass manual valve not open, the associated Unit 1 and Unit 2 RHRSW subsystems and ESW subsystem are not provided a return path to the UHS. As a result, the associated RHRSW subsystems and ESW subsystem must be declared inoperable.

With one large spray array valve not capable of being opened on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the full required spray cooling capability of the affected UHS return path. With one large spray array valve not capable of being closed on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the small spray array when loop flows are low as the required spray nozzle pressure is not achievable for the small spray array. As a result, the associated RHRSW subsystems must be declared inoperable.

With one small spray array valve not capable of being opened on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the spray cooling function of the affected UHS return path for low loop flow rates. For a single failure of the large spray array valve in the closed position, design bases LOCA/LOOP calculations assume that flow is reduced on the affected loop within 3 hours after the event to allow use of the small spray array. With one small spray array valve not capable of being closed on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the large spray array for a flow path as the required nozzle pressure is not achievable for the large spray array. As a result, the associated RHRSW subsystems must be declared inoperable.

Insert B 3.7-5B

With any UHS return path valve listed in Tables 3.7.1-1, 3.7.1-2, or 3.7.1-3 inoperable, the UHS return path is no longer single failure proof.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.1.5

UHS return header

The ~~return loop~~ large spray array valves are required to open in order for the UHS to perform its design function. These valves are manually actuated from either the control room or the remote shutdown panel, under station operating procedure, when the RHRSW system is required to remove energy from the reactor vessel or suppression pool. A large spray array valve is considered inoperable if it cannot be opened on demand, because the valve must be opened to allow spray cooling to occur. This SR demonstrates that the valves will move to their required positions when required. The 92-day Test Frequency is based upon engineering judgment and operating/testing history that indicates this frequency gives adequate assurance that the valves will move to their required positions when required.

REFERENCES

1. FSAR, Section 9.2.6.
2. FSAR, Chapter 6.
3. FSAR, Chapter 15.
4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

Insert B 3.7-6cA

Insert B 3.7-6cA

SR 3.7.1.6

The small spray array valves HV-012224A2 and B2 are required to be closed in order for the UHS to perform its design function. These valves are manually actuated from the control room or the remote shutdown panel, under station operating procedure, when the RHRSW system is required to remove energy from the reactor vessel or suppression pool. A small spray array valve is considered inoperable if it cannot be closed when required to support design bases analyses lineups. The small spray array valve has to be closed for the large spray array to be capable of design bases cooling capacity. This SR demonstrates that the valves will move to their required positions when required. The 92-day Test Frequency is based upon engineering judgment and operating/testing history that indicates this frequency gives adequate assurance that the valves will move to their required positions when required.

SR 3.7.1.7

The spray array bypass manual valves 012287A and B are required to be closed in the event of a failure of the spray array bypass valves to close in order for the UHS to perform its design function. A spray array bypass manual valve is considered inoperable if it is not capable of being closed in a timely manner as described in the design bases analyses (3 hours from the time the spray array bypass valve fails to close and the UHS temperature exceeds the requirements in SR 3.7.1.2.)

B 3.7 PLANT SYSTEMS

B 3.7.2 Emergency Service Water (ESW) System

BASES

BACKGROUND

The ESW System is designed to provide cooling water for the removal of heat from equipment, such as the diesel generators (DGs), residual heat removal (RHR) pump coolers, and room coolers for Emergency Core Cooling System equipment, required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. Upon receipt of a loss of offsite power or loss of coolant accident (LOCA) signal, ESW pumps are automatically started after a time delay.

The ESW System consists of two independent and redundant subsystems. Each of the two ESW subsystems is made up of a header, two pumps, a suction source, valves, piping and associated instrumentation. The two subsystems are separated from each other so an active single failure in one subsystem will not affect the OPERABILITY of the other subsystem. A continuous supply of water is provided to ESW from the Service Water System for the keepfill system. This supply is not required for ESW operability.

Cooling water is pumped from the Ultimate Heat Sink (UHS) by the ESW pumps to the essential components through the two main headers. After removing heat from the components, the water is discharged to the spray pond (UHS) by way of a network of sprays that dissipate the heat to the atmosphere or directly to the UHS via a bypass ~~valve.~~ header.

APPLICABLE SAFETY ANALYSES

Sufficient water inventory is available for all ESW System post LOCA cooling requirements for a 30 day period with no additional makeup water source available. The ability of the ESW System to support long term cooling is assumed in evaluations of the equipment required for safe reactor shutdown presented in the FSAR, Chapters 4 and 6 (Refs. 1 and 2, respectively).

The ability of the ESW System to provide adequate cooling to the identified safety equipment is an implicit assumption for the safety analyses evaluated in References 1 and 2. The ability to provide onsite emergency AC power is dependent on the ability of the ESW System to cool the DGs. The long term cooling capability of the RHR and core spray pumps is also dependent on the cooling provided by the ESW System.

The ESW System satisfies Criterion 3 of the NRC Policy Statement. (Ref. 3)

(continued)

BASES (continued)

LCO

The ESW subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of ESW is required to provide the minimum heat removal capability assumed in the safety analysis for the system to which it supplies cooling water. To ensure this requirement is met, two subsystems of ESW must be OPERABLE. At least one subsystem will operate, if the worst single active failure occurs coincident with the loss of offsite power.

A subsystem is considered OPERABLE when it has two OPERABLE pumps, and an OPERABLE flow path capable of taking suction from the UHS and transferring the water to the appropriate equipment and returning flow to the UHS. If individual loads are isolated, the affected components may be rendered inoperable, but it does not necessarily affect the OPERABILITY of the ESW System. Because each ESW subsystem supplies all four required DGs, an ESW subsystem is considered OPERABLE if it supplies at least three of the four DGs provided no single DG does not have an ESW subsystem capable of supplying flow.

An adequate suction source is not addressed in this LCO since the minimum net positive suction head of the ESW pumps is bounded by the Residual Heat Removal Service Water System requirements (LCO 3.7.1, "Residual Heat Removal System and Ultimate Heat Sink (UHS)").

The ESW return loop requirement, in terms of operable UHS return paths or UHS spray capacity, is also not addressed in this LCO. UHS operability, in terms of the return loop and spray capacity is addressed in the RHRSW/ UHS Technical Specification (LCO 3.7.1, "Residual Heat Removal Service Water System and Ultimate Heat Sink (UHS)). ~~The design basis calculations for the UHS assume post-accident ESW return flow through the spray bypass valve on one return loop until a UHS temperature is reached whereby realignment of appropriate ESW heat loads to the spray loop is required. This realignment is manual and can be done several hours or more after accident initiation.~~

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Turbine Bypass System

BASES

22

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 full bypass capacity of the system is approximately 25% 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 Main Turbine Bypass System consists of five valves connected to the main steam lines between the main steam isolation valves and the turbine stop valve bypass valve chest. Each of these five valves is operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Electro Hydraulic Control System, as discussed in the FSAR, Section 7.7.1.5 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves that direct all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows from the bypass chest, through connecting piping, to the pressure breakdown assemblies, where a series of orifices are used to further reduce the steam pressure before the steam enters the condenser.

APPLICABLE SAFETY ANALYSES

The Main Turbine Bypass System has two modes of operation. A fast opening mode is assumed to function during the turbine generator load rejection, turbine trip, and feedwater controller failure transients as discussed in FSAR Sections 15.2.2, 15.2.3, and 15.1.2 (Refs. 2, 3, and 4). A pressure regulation mode is assumed to function during the control rod withdrawal error and recirculation flow controller failure transients as discussed in FSAR Sections 15.4.2 and 15.4.5 (Refs. 5 and 6). Both modes of operation are assumed to function for all bypass valves assumed in the applicable safety analyses. Opening the bypass valves during the above transients mitigates the increase in reactor vessel pressure, which affects both MCPR and LHGR during the event. An inoperable Main Turbine Bypass System may result in a MCPR and / or LHGR penalty.

The Main Turbine Bypass System satisfies Criterion 3 of the NRC Policy Statement. (Ref. 7)

(continued)

BASES (continued)

LCO

The Main Turbine Bypass System fast opening and pressure regulation modes are required to be OPERABLE to limit the pressure increase in the main steam lines and reactor pressure vessel during transients that cause a pressurization so that the Safety Limit MCPR and LHGR are not exceeded. With the Main Turbine Bypass System inoperable, modifications to the MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and LHGR limits (LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)") may be applied to allow this LCO to be met. The MCPR and LHGR limits for the inoperable Main Turbine Bypass System are specified in the COLR. An OPERABLE Main Turbine Bypass System requires the bypass valves to open in response to increasing main steam line pressure. Licensing analyses credit an OPERABLE Main Turbine Bypass System as having both the bypass valve fast opening mode and pressure regulation mode. The fast opening mode is required for transients initiated by a turbine control valve or turbine stop valve closure. The pressure regulation mode is required for transients where the power increase exceeds the capability of the turbine control valves.

The cycle specific safety analyses assume a certain number of OPERABLE main turbine bypass valves as an input (i.e., one through five). Therefore, the Main Turbine Bypass System is considered OPERABLE when the number of OPERABLE bypass valves is greater than or equal to the number assumed in the safety analyses. The number of bypass valves assumed in the safety analyses is specified in the COLR. This response is within the assumptions of the applicable analysis (Refs. 2 – 6).

23

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at ≥ ~~25%~~ RTP to ensure that the fuel cladding integrity Safety Limit is not violated during all applicable transients. As discussed in the Bases for LCOs 3.2.2 and 3.2.3, sufficient margin to these limits exists at < 25% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If the Main Turbine Bypass System is inoperable and the MCPR and LHGR limits for an inoperable Main Turbine Bypass System, 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 MCPR and LHGR limits accordingly. The 2-hour Completion Time is reasonable, based on the time to complete the Required Action and

(continued)

BASES

ACTIONS

A.1 (continued)

the low probability of an event occurring during this period requiring the Main Turbine Bypass System.

B.1

23

If the Main Turbine Bypass System cannot be restored to OPERABLE status or the MCPR and LHGR limits for an inoperable Main Turbine Bypass System are not applied, THERMAL POWER must be reduced to < 25% RTP. As discussed in the Applicability section, operation at < 25% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the applicable transients. 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 3.7.6.1

Cycling each required main turbine bypass valve through one complete cycle of full travel (including the fast opening feature) 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. Operating experience has shown that these components usually pass the SR when performed at the 31-day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.6.2

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 (simulate automatic actuation), the valves will actuate to their required position. The 24-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 24-month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.8 Main Turbine Pressure Regulation System

BASES

BACKGROUND	The Main Turbine Pressure Regulation System is designed to control main steam pressure. The Main Turbine Pressure Regulation System contains two pressure regulators which are provided to maintain primary system pressure control. They independently sense pressure just upstream of the main turbine stop valves and compare it to two separate setpoints to create proportional error signals that produce each regulator's output. The outputs of both regulators feed into a high value gate. The regulator with the highest output controls the main turbine control valves. The lowest pressure setpoint gives the largest pressure error and thereby the largest regulator output. The backup regulator is nominally set 3 psi higher giving a slightly smaller error and a slightly smaller effective output of the controller. The main turbine pressure regulation function of the Turbine Electro Hydraulic Control System is discussed in the FSAR, Sections 7.7.1.5 (Ref. 1) and 15.2.1 (Ref. 2).
APPLICABLE SAFETY ANALYSES	A downscale failure of the primary or controlling pressure regulator as discussed in FSAR, Section 15.2.1 (Ref. 2) will cause the turbine control valves to begin to close momentarily. The pressure will increase, because the reactor is still generating the initial steam flow. The backup regulator will reposition the valves and re-establish steady-state operation above the initial pressure equal to the setpoint difference which is nominally 3 psi. Provided that the backup regulator takes control, the disturbance is mild, similar to a pressure setpoint change and no significant reduction in fuel thermal margins occur. Failure of the backup pressure regulator is also discussed in FSAR, Section 15.2.1. If the backup pressure regulator fails downscale or is out of service when the primary regulator fails downscale, the turbine control valves (TCVs) will close in the servo or normal operating mode. Since the TCV closure is not a fast closure, there is no loss of EHC pressure to provide an anticipatory scram. The reactor pressure will increase to the point that a high neutron flux or a high reactor pressure scram is initiated to shut down the reactor. The increase in flux and pressure affects both MCPR and LHGR during the event. An inoperable Main Turbine Pressure Regulation System may result in a MCPR and / or LHGR penalty. The Main Turbine Pressure Regulation System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

LCO

Both Main Turbine Pressure Regulators are required to be OPERABLE to limit the pressure increase in the main steam lines and reactor pressure vessel during a postulated failure of the controlling pressure regulator so that the Safety Limit MCPR and LHGR are not exceeded. With one Main Turbine Pressure Regulator inoperable, modifications to the MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and LHGR limits (LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)") may be applied to allow this LCO to be met. The MCPR and LHGR limits for the inoperable Main Turbine Pressure Regulation System are specified in the COLR. An OPERABLE Main Turbine Pressure Regulation System requires that both Main Turbine Pressure Regulators be available so that if the controlling regulator fails downscale (i.e., in the direction of reduced control valve demand) a backup regulator is available to regain pressure control before fuel thermal margins can be significantly affected. An OPERABLE Main Turbine Pressure Regulation System causes the event where the controlling regulator fails downscale to be a non-limiting event from a thermal margin standpoint.

APPLICABILITY

The Main Turbine Pressure Regulation System is required to be OPERABLE at ≥ 23% RTP to ensure that the fuel cladding integrity Safety Limit is not violated during all applicable transients. As discussed in the Bases for LCOs 3.2.2 and 3.2.3, sufficient margin to these limits exists at < 23% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If one Main Turbine Pressure Regulator is inoperable and the MCPR and LHGR limits for an inoperable Main Turbine Pressure Regulation System, 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 Pressure Regulation System to OPERABLE status or adjust the MCPR and LHGR to be within the applicable limits accordingly. The 2-hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of a downscale failure of a Main Turbine Pressure Regulator.

(continued)

BASES (continued)

ACTIONS

B.1

If the Main Turbine Pressure Regulation System cannot be restored to OPERABLE status or the MCPR and LHGR limits for an inoperable Main Turbine Pressure Regulation System are not applied, THERMAL POWER must be reduced to < 23% RTP. As discussed in the Applicability section, operation at < 23% RTP results in sufficient margin to the required limits, and the Main Turbine Pressure Regulation System is not required to protect fuel integrity during the applicable transients.

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 3.7.8.1

Verifying that both Main Turbine Pressure Regulators can be independently used to control pressure demonstrates that the Main Turbine Pressure Regulation System is OPERABLE and will function as required. The 92-day Frequency is based on engineering judgment, is consistent with the procedural controls governing pressure regulator operation, and ensures proper control of main turbine pressure. Operating experience has shown that these components usually pass the SR when performed at the 92-day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.8.2

The Main Turbine Pressure Regulators are designed so that a downscale failure of the controlling regulator will result in the backup regulator automatically assuming control. This SR demonstrates that, with the failure of the controlling pressure regulator, the backup pressure regulator will assume control. The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage or unit start-up and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 24-month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

(continued)

BASES

REFERENCES	1. FSAR, Section 7.7.1.5.
	2. FSAR, Section 15.2.1.

(continued)

Technical Specifications Bases Changes
Unit 2
(Mark-up)

BASES

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 limit 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 the 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 limit.

2.1.1.1 Fuel Cladding Integrity

The use of the ANFB-10 (Reference 4) correlation is valid for critical power calculations at pressures > 571 psia and bundle mass fluxes > 0.115 x 10^6 lb/hr-ft^2 for ANFB-10. 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:

> Provided that the water level in the vessel downcomer is maintained above the top of the active fuel, natural circulation is sufficient to ~~ensure a minimum~~ bundle flow for all fuel assemblies that have a relatively high power and potentially can approach a critical heat flux condition. For the SPC FANP Atrium 10 design, the minimum bundle flow is > 28 x 10^3 lb/hr. For Atrium-10 fuel design, the coolant minimum bundle flow and maximum area are such that the mass flux is always > .25 x 10^6 lb/hr-ft^2. Full scale critical power ~~test data~~ taken from various SPC and GE fuel designs at pressures from 14.7 psia to 1400 psia indicate the fuel assembly ~~critical~~ power at 0.25 x 10^6 lb/hr-ft^2 is approximately 3.35 MWt. At 25 23% RTP, a bundle power of ~~approximately~~ 3.35 MWt corresponds to a bundle radial peaking factor of approximately 3.0 2.8, which is significantly higher than ~~the~~ expected peaking factor. Thus, a THERMAL POWER limit of 25 23% RTP for reactor pressures < 785 psig is conservative and for conditions of lesser power would remain the same.

2.1.1.2 MCPR

The MCPR SL ensures sufficient conserva~~tism 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

the residual heat removal shutdown cooling piping and in the recirculation loop piping. This quantity of borated solution is the amount that is above the pump suction shutoff level in the boron solution storage tank. No credit is taken for the portion of the tank volume that cannot be injected. The minimum concentration of 13.6 weight percent ensures compliance with the requirements of 10 CFR 50.62 (Ref. 1).

The SLC System satisfies the requirements of the NRC Policy Statement (Ref. 3) because operating experience and probabilistic risk assessments have shown the SLC System to be important to public health and safety. Thus, it is retained in the Technical Specifications.

LCO

The OPERABILITY of the SLC System provides backup capability for reactivity control independent of normal reactivity control provisions provided by the control rods. The OPERABILITY of the SLC System is based on the conditions of the borated solution in the storage tank and the availability of a flow path to the RPV, including the OPERABILITY of the pumps and valves. Two SLC subsystems are required to be OPERABLE; each contains an OPERABLE pump, an explosive valve, and associated piping, valves, and instruments and controls to ensure an OPERABLE flow path.

APPLICABILITY

In MODES 1 and 2, shutdown capability is required. In MODES 3 and 4, control rods are not able to be withdrawn (except as permitted by LCO 3.10.3 and LCO 3.10.4) since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate controls to ensure that the reactor remains subcritical. In MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Demonstration of adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") ensures that the reactor will not become critical. Therefore, the SLC System is not required to be OPERABLE when only a single control rod can be withdrawn.

(continued)

INSERT B 3.1-41A

BASES (continued)

ACTIONS

A.1

~~If the boron solution concentration is less than the required limits for compliance with 10 CFR 50.62 (Ref. 1) (≥ 13.6 weight percent) but greater than the concentration required for cold shutdown (original licensing basis), the concentration must be restored to within limits > 13.6 weight percent in 72 hours. It is not necessary under these conditions to enter Condition C for both SLC subsystems inoperable since they are capable of performing their original design basis function. Because of the low probability of an event and the fact that 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.~~

~~The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of concentration out of limits or inoperable SLC subsystems during any single continuous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, an SLC subsystem is inoperable and that subsystem is subsequently returned to OPERABLE, the LCO may already have been not met for up to 7 days. This situation could lead to a total duration of 10 days (7 days in Condition B, followed by 3 days in Condition A), since initial failure of the LCO, to restore the SLC System. Then an SLC subsystem could be found inoperable again, and concentration could be restored to within limits. This could continue indefinitely.~~

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock," resulting in establishing the "time zero" at the time the LCO was initially not met instead of at the time Condition A was entered. The 10 day Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.~~

B.1

If one SLC subsystem is inoperable for reasons other than Condition A, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystem is adequate to perform the

(continued)

Insert B 3.1- 41A

A-1

If the boron solution concentration is not within the limits in Figure 3.1.7-1, the operability of both SLC subsystems is impacted and the concentration must be restored to within limits within 8 hours. The allowed Completion Time of 8 hours is considered acceptable given the low probability of an event occurring concurrent with the failure of the control rods to shut down the reactor.

BASES

ACTIONS

B.1 (continued)

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 an event occurring concurrent with the failure of the Control Rod Drive (CRD) System to shut down the plant.

~~The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of concentration out of limits or inoperable SLC subsystems during any single continuous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, concentration is out of limits, and is subsequently returned to within limits, the LCO may already have been not met for up to 3 days. This situation could lead to a total duration of 10 days (3 days in Condition A, followed by 7 days in Condition B), since initial failure of the LCO, to restore the SLC System. Then concentration could be found out of limits again, and the SLC subsystem could be restored to OPERABLE. This could continue indefinitely.~~

~~This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock," resulting in establishing the "time zero" at the time the LCO was initially not met instead of at the time Condition B was entered. The 10 day Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.~~

C.1

If both SLC subsystems are inoperable for reasons other than Condition A, at least one subsystem must be restored to OPERABLE status within 8 hours. The allowed Completion Time of 8 hours is considered acceptable given the low probability of an event occurring concurrent with the failure of the control rods to shut down the reactor.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.7

1250 40.0

Demonstrating that each SLC System pump develops a flow rate ≥ 41.2 gpm at a discharge pressure ≥ 1395 psig without actuating the pump's relief valve ensures that pump performance has not degraded during the fuel cycle. Testing at 1395 psig assures that the functional capability of the SLC System meets the ATWS Rule (10 CFR 50.62) (Ref. 1) requirements. 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

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. The pump and explosive valve tested should be alternated such that both complete flow paths are tested every 48 months at alternating 24 month intervals. The Surveillance may be performed in separate steps to prevent injecting solution 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 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

Demonstrating that all heat traced piping between the boron solution storage tank and the suction inlet to the injection

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.8 and SR 3.1.7.9 (continued)

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. This test can be performed by any series of overlapping or total flow path test so that the entire flow path is included. The 24 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 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 or the heat trace was not properly energized and building temperature was below the temperature at which the SLC solution would precipitate out, SR 3.1.7.9 must be performed once within 24 hours after the piping temperature is restored to within the limits of Figure 3.1.7-2.

REFERENCES

1. 10 CFR 50.62.
2. FSAR, Section 9.3.5.
3. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

INSERT B3.1-46A

Insert B3.1-46A

SR3.1.7.10

Enriched sodium pentaborate solution is made by mixing granular, enriched sodium pentaborate with water. Verification of the actual B-10 enrichment must be performed prior to addition to the SLC tank in order to ensure that the proper B-10 atom percentage is being used. This verification may be based on independent isotopic analysis or a manufacturer certificate of compliance.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The SPC LOCA analyses consider the delay in Low Pressure Coolant Injection (LPCI) availability when the unit is operating in the Suppression Pool Cooling Mode. The delay in LPCI availability is due to the time required to realign valves from the Suppression Pool Cooling Mode to the LPCI mode. The results of the analyses demonstrate that the PCTs are within the 10 CFR 50.46 limit.

Finally, the SPC LOCA analyses were performed for Single-Loop Operation. The results of the SPC analysis for ATRIUM™-10 fuel shows that an APLHGR limit which is 0.8 times the two-loop APLHGR limit meets the 10 CFR 50.46 acceptance criteria, and that the PCT is less than the limiting two-loop PCT.

The APLHGR satisfies Criterion 2 of the NRC Policy Statement (Ref. 10).

LCO

The APLHGR limits specified in the COLR are the result of the DBA analyses.

APPLICABILITY

23

The APLHGR limits are primarily derived from LOCA 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. At THERMAL POWER levels < 25% RTP, the reactor is operating with substantial margin to the APLHGR limits; thus, this LCO is not required.

ACTIONS

A.1

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

(continued)

BASES

ACTIONS (continued)

B.1

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

23

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

23 44

APLHGRs are required to be initially calculated within 24 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. Additionally, APLHGRs must be calculated prior to exceeding 50% RTP unless performed in the previous 24 hours. APLHGRs 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 during normal operation. The 24 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels and because the APLHGRs must be calculated prior to exceeding 50% ~~RTP~~.

REFERENCES

1. Not Used
2. Not Used
3. EMF-2361(P)(A), "EXEM BWR-2000 ECCS Evaluation Model," Framatome ANP.
4. EMF-2292(P)(A) Revision 0, "ATRIUM™-10: Appendix K Spray Heat Transfer Coefficients."
5. XN-CC-33(P)(A) Revision 1, "HUXY: A Generalized Multirod Heatup Code with 10CFR50 Appendix K Heatup Option Users Manual," November 1975.

(continued)

APPLICABLE SAFETY ANALYSES (continued)

combinations of plant conditions (i.e., control rod scram speed, bypass valve performance, EOC-RPT, cycle exposure, etc.). Flow dependent MCPR limits are determined by analysis of slow flow runout transients.

The MCPR satisfies Criterion 2 of the NRC Policy Statement (Ref. 11).

LCO

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the flow dependent MCPR and power dependent MCPR 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 minimum 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. 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% 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 provides rapid scram initiation for any significant power increase transient, which effectively eliminates any MCPR compliance concern. Therefore, at THERMAL POWER levels < 25% RTP, the reactor is operating with substantial margin to the MCPR limits and this LCO is not required.

23

ACTIONS

A.1

If any MCPR is outside the required limits, 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 limits such that the plant remains operating within

(continued)

ACTIONS

A.1 (continued)

analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the MCPR(s) to within its limits and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the MCPR out of specification.

B.1

23

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

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

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The MCPR is required to be initially calculated within 24 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. Additionally, MCPR must be calculated prior to exceeding 50% RTP unless performed in the previous 24 hours. MCPR 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 24 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels and because the MCPR must be calculated prior to exceeding 50% RTP.

SR 3.2.2.2

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Because the transient analysis takes credit for conservatism in the scram time performance, it must be demonstrated that the specific scram time is consistent with those used in the transient analysis. SR 3.2.2.2 compares the average measured scram times to the assumed scram times documented in the COLR. The COLR contains a table of scram times based on the LCO 3.1.4, "Control Rod Scram Times" and the realistic scram times, both of which are used in the transient analysis. If the average measured scram times are greater than the realistic scram times then the MCPR operating limits corresponding to the Maximum Allowable Average Scram Insertion Time must be implemented.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

The LHGR satisfies Criterion 2 of the NRC Policy Statement (Ref. 5).

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

23

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

ACTIONS

A.1

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

B.1

23

If the LHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER is 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

23

The LHGR is required to be initially calculated within 24 hours after THERMAL POWER ~~is ≥~~ 25% RTP and then every 24 hours thereafter. Additionally, LHGRs must be calculated prior to exceeding 50% RTP unless performed in the previous 24 hours. The LHGR 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 slow changes in power ~~distribution~~ during normal operation. The 24 hour allowance after THERMAL POWER ≥ 25% RTP is ~~achieved~~ is acceptable given the large inherent margin ~~to operating~~ limits at lower power levels and because the ~~LHGRs~~ must be calculated prior to exceeding 50% ~~RTP~~.

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REFERENCES

1. FSAR, Section 4.
2. FSAR, Section 5.
3. NUREG-0800, Section II.A.2(g), Revision 2, July 1981.
4. ANF-89-98(P)(A) Revision 1 and Revision 1 Supplement 1, "Generic Mechanical Design Criteria for BWR Fuel Design," Advanced Nuclear Fuels Corporation, May 1995.
5. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Average Power Range Monitor (APRM) (continued)

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no signal 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 the APRM Functions 2.a, 2.b, and 2.c, 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 channel, with no more than (9), LPRM detectors declared inoperable since the most recent APRM gain calibration. Per Reference 23, the minimum input requirement for an APRM channel with 43 LPRM inputs is determined given that the total number of LPRM outputs used as inputs to an APRM channel that may be bypassed shall not exceed twenty-three (23). Hence, (20) LPRM inputs needed to be operable. For the OPRM Trip Function 2.f, each LPRM in an APRM channel is further associated in a pattern of OPRM "cells," as described in References 17 and 18. Each OPRM cell is capable of producing a channel trip signal.

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.

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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.

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

(continued)

Retyped to Include PRNMS and ARTS/MELLA

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

References 17, 18 and 19 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm (confirmation count and cell amplitude), the amplitude based algorithm, and the growth rate algorithm. All three are implemented in the OPRM Trip Function, but the safety analysis takes credit only for the period based detection algorithm. The remaining algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Trip Function OPERABILITY for Technical Specification purposes is based only on the period based detection algorithm.

The OPRM Trip Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into "cells" for evaluation by the OPRM algorithms. 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. Three of the four channels are required to be OPERABLE.

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The OPRM Trip is automatically enabled (bypass removed) when THERMAL POWER is ≥ ~~30~~% RTP, as indicated by the APRM Simulated Thermal Power, and reactor core flow is ≤ the value defined in the COLR, as indicated by APRM measured recirculation drive flow. This is the operating region where actual thermal-hydraulic instability and related neutron flux oscillations are expected to occur. Reference 21 includes additional discussion of OPRM Trip enable region limits.

These setpoints, which are sometimes referred to as the "auto-bypass" setpoints, establish the boundaries of the OPRM Trip enabled region. The APRM Simulated Thermal Power auto-enable setpoint has 1% deadband while the drive flow setpoint has a 2% deadband. The deadband for these setpoints is established so that it increases the enabled region once the region is entered.

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23

The OPRM Trip Function is required to be OPERABLE when the plant is at ≥ ~~25~~% RTP. The ~~25~~% RTP level is selected to provide margin in the unlikely event that a reactor power increase transient occurring without operator action while the plant is operating below ~~30~~% RTP causes a power increase to or beyond the ~~30~~% APRM Simulated Thermal Power OPRM Trip auto-enable setpoint. This OPERABILITY requirement assures that the OPRM Trip auto-enable function will be OPERABLE when required.

(continued)

Retyped to ~~Include PRNMS and ARTS/MELLA~~

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

8. Turbine Stop Valve—Closure (continued)

valves. The Turbine Stop Valve—Closure Function is the primary scram signal for the turbine trip event analyzed in Reference 5. 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 signals are initiated from position switches located on each of the four TSVs. Two independent position switches are associated with each stop valve. One of the two switches 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 channels, each consisting of one position switch. The logic for the Turbine Stop Valve—Closure Function is such that three or more TSVs must be closed to produce a scram. This Function must be enabled at THERMAL POWER ≥ 30% RTP. This is accomplished automatically by pressure instruments sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this function non-conservatively, THERMAL POWER is derived from first stage pressure. The main turbine bypass valves must not cause the trip Function to be bypassed when THERMAL POWER is ≥ 30% RTP.

26

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

Eight channels (arranged in pairs) of Turbine Stop Valve—Closure 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 ≥ 30% RTP. This Function is not required when THERMAL POWER is < 30% RTP since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Neutron Flux—High Functions are adequate to maintain the necessary safety margins.

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(continued)

Retyped to Include PRNMS and ARTS/MELLA

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

9. 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 5. 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 electrohydraulic control (EHC) fluid pressure at each control valve. One pressure instrument is associated with each control valve, and the signal from each transmitter is assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER ≥ 30% RTP. This is accomplished automatically by pressure instruments sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this function non-conservatively, THERMAL POWER is derived from first stage pressure. The main turbine bypass valves must not cause the trip Function to be bypassed when ~~THERMAL POWER is~~ ≥ 30% RTP.

26

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 ≥ 30% RTP. This Function is not required when THERMAL POWER is < 30% RTP, since the Reactor Vessel Steam Dome ~~Pressure—High~~ and the Average Power Range Monitor Neutron Flux—High Functions are adequate to maintain the necessary safety margins.

26

(continued)

Retyped to ~~Include~~ PRNMS ~~and ARTS~~/MELLA

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.1 and SR 3.3.1.1.2 (continued)

Agreement criteria which are determined by the plant staff based on an investigation of a combination of the channel instrument uncertainties, may be used to support this parameter comparison and include indication and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit, and does not necessarily indicate the channel is Inoperable.

The Frequency of once every 12 hours for SR 3.3.1.1.1 is based upon operating experience that demonstrates that channel failure is rare. The Frequency of once every 24 hours for SR 3.3.1.1.2 is based upon operating experience that demonstrates that channel failure is rare and the evaluation in References 15 and 16. The CHANNEL CHECK supplements less formal checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.3

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 3.3.1.1.8.

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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, LHGR 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.

(continued)

Retyped to Include PRNMS and ARTS/MELLA

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.8

LPRM gain settings are determined from the local flux profiles that are either measured by the Traversing Incore Probe (TIP) System at all functional locations or calculated for TIP locations that are not functional. The methodology used to develop the power distribution limits considers the uncertainty for both measured and calculated local flux profiles. This methodology assumes that all the TIP locations are functional for the first LPRM calibration following a refueling outage, and a minimum of 25 functional TIP locations for subsequent LPRM calibrations. The calibrated LPRMs establish the relative local flux profile for appropriate representative input to the APRM System. The ~~1000~~ 2000 MWD/MT Frequency is based on operating experience with LPRM sensitivity changes.

SR 3.3.1.1.9 and SR 3.3.1.1.14

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. The 92 day Frequency of SR 3.3.1.1.9 is based on the reliability analysis of Reference 9.

SR 3.3.1.1.9 is modified by a Note that provides a general exception to the definition of CHANNEL FUNCTIONAL TEST. This exception is necessary because the design of instrumentation does not facilitate functional testing of all required contacts of the relay which input into the combinational logic. (Reference 10) Performance of such a test could result in a plant transient or place the plant in an undo risk situation. Therefore, for this SR, the CHANNEL FUNCTIONAL TEST verifies acceptable response by verifying the change of state of the relay which inputs into the combinational logic. The required contacts not tested during the CHANNEL FUNCTIONAL TEST are tested under the LOGIC SYSTEM FUNCTIONAL TEST, SR 3.3.1.1.15. This is acceptable because operating experience shows that the contacts not tested during the CHANNEL FUNCTIONAL TEST normally pass the LOGIC SYSTEM FUNCTIONAL TEST, and the testing methodology minimizes the risk of unplanned transients.

(continued)

~~Retyped to Include PRNMS and ARTS/MELLA~~

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.9 and SR 3.3.1.1.14 (continued)

The 24 month Frequency of SR 3.3.1.1.14 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 24 month Frequency.

SR 3.3.1.1.10, SR 3.3.1.1.11, SR 3.3.1.1.13, and SR 3.3.1.1.18

A CHANNEL CALIBRATION verifies that the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

Note 1 for SR 3.3.1.1.18 states that neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.3) and the 2000 ~~1000~~ MWD/MT LPRM calibration against the TIPs (SR 3.3.1.1.8).

A Note is provided for SR 3.3.1.1.11 that requires the IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM and IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

(continued)

Retyped to Include PRNMS and ARTS/MELLA

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.15 (continued)

The LOGIC SYSTEM FUNCTIONAL TEST for APRM Function 2.e simulates APRM and OPRM trip conditions at the 2-out-of-4 Voter channel inputs to check all combinations of two tripped inputs to the 2-out-of-4 logic in the voter channels and APRM related redundant RPS relays.

The 24 month Frequency is based on the need to perform portions of 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 24 month Frequency.

SR 3.3.1.1.16

This SR ensures that scrams initiated from the Turbine Stop Valve—Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 30% RTP. This is performed by a Functional check that ensures the scram feature is ~~not bypassed~~ at ≥ 30% RTP. Because main turbine bypass ~~flow~~ can affect this function nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the opening of the main turbine bypass valves must not cause the trip Function to be bypassed when Thermal Power is ≥ 30% RTP.

26

If any bypass channel's trip function is nonconservative (i.e., the Functions are bypassed at ≥ 30% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve—Closure 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 24 months is based on engineering judgment and reliability of the components.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.19

This surveillance involves confirming the OPRM Trip auto-enable setpoints. The auto-enable setpoint values are considered to be nominal values as discussed in Reference 21. This surveillance ensures that the OPRM Trip is enabled (not bypassed) for the correct values of APRM Simulated Thermal Power and recirculation drive flow. Other surveillances ensure that the APRM Simulated Thermal Power and recirculation drive flow properly correlate with THERMAL POWER (SR 3.3.1.1.2) and core flow (SR 3.3.1.1.20), respectively.

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If any auto-enable setpoint is nonconservative (i.e., the OPRM Trip is bypassed when APRM Simulated Thermal Power ≥ 20% and recirculation drive flow ≤ value equivalent to the core flow value defined in the COLR, then the affected channel is considered inoperable for the OPRM Trip Function. Alternatively, the OPRM Trip auto-enable setpoint(s) may be adjusted to place the channel in a conservative condition (not bypassed). If the OPRM Trip is placed in the not-bypassed condition, this SR is met and the channel is considered OPERABLE.

For purposes of this surveillance, consistent with Reference 21, the conversion from core flow values defined in the COLR to drive flow values used for this SR can be conservatively determined by a linear scaling assuming that 100% drive flow corresponds to 100 Mlb/hr core flow, with no adjustment made for expected deviations between core flow and drive flow below 100%.

The Frequency of 24 months is based on engineering judgment and reliability of the components.

SR 3.3.1.1.20

The APRM Simulated Thermal Power-High Function (Function 2.b) uses drive flow to vary the trip setpoint. The OPRM Trip Function (Function 2.f) uses drive flow to automatically enable or bypass the OPRM Trip output to RPS. Both of these Functions use drive flow as a representation of reactor core flow. SR 3.3.1.1.18 ensures that the drive flow transmitters and processing electronics are calibrated. This SR adjusts the recirculation drive flow scaling factors in each APRM channel to provide the appropriate drive flow/core flow alignment.

(continued)

B 3.3 INSTRUMENTATION

B 3.3.2.2 Feedwater – Main Turbine High Water Level Trip Instrumentation

BASES

BACKGROUND

The feedwater - main turbine high water level trip instrumentation is designed to detect a potential failure of the Feedwater Level Control System that causes excessive feedwater flow.

With excessive feedwater flow, the water level in the reactor vessel rises toward the high water level, Level 8 reference point, causing the trip of the three feedwater pump turbines and the main turbine.

Reactor Vessel Water Level—High, Level 8 signals are provided by level sensors 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 in the reactor vessel (variable leg). Three channels of Reactor Vessel Water Level—High, Level 8 instrumentation are provided as input to a two-out-of-three initiation logic that trips the three feedwater pump turbines and the main turbine. When the setpoint is exceeded, the channel sensor actuates, which then outputs a main feedwater and turbine trip signal to the trip logic.

A trip of the feedwater pump turbines limits further increase in reactor vessel water level by limiting further addition of feedwater to the reactor vessel. A trip of the main turbine and closure of the stop valves protects the turbine from damage due to water entering the turbine.

APPLICABLE SAFETY ANALYSES

The feedwater - main turbine high water level trip instrumentation is assumed to be capable of providing a turbine trip in the design basis transient analysis for a feedwater controller failure, maximum demand event (Ref. 1). The Level 8 trip indirectly initiates a reactor scram from the main turbine trip (above 80% RTP) and trips the feedwater pumps, thereby terminating the event. The reactor scram mitigates the reduction in MCPR.

26

(continued)

BASES (continued)

23

APPLICABILITY

The feedwater - main turbine high water level trip instrumentation is required to be OPERABLE at ≥ 25% RTP to ensure that the fuel cladding integrity Safety Limit is not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases of LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," sufficient margin to these limits exists below 25% RTP; therefore, the requirements are only necessary when operating at or above this power level.

ACTIONS

A Note has been provided to modify the ACTIONS related to feedwater - main turbine high water level trip 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 feedwater - main turbine high water level trip instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable feedwater - main turbine high water level trip instrumentation channel.

A.1

With one channel inoperable, the remaining two OPERABLE channels can provide the required trip signal. However, overall instrumentation reliability is reduced because a single failure in one of the remaining channels concurrent with feedwater controller failure, maximum demand event, may result in the instrumentation not being able to perform its intended function. Therefore, continued operation is only allowed for a limited time with one channel inoperable. If the inoperable channel cannot be restored to OPERABLE status within the Completion Time, the channel must be placed in the tripped condition per Required Action A.1. Placing the

(continued)

BASES

ACTIONS

B.1 (continued)

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 feedwater - main turbine high water level trip instrumentation occurring during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2 for Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1

23

With the required channels not restored to OPERABLE status or placed in trip, THERMAL POWER must be reduced to < 25% RTP within 4 hours. As discussed in the Applicability section of the Bases, operation below 25% RTP results in sufficient margin to the required limits, and the feedwater - main turbine high water level trip instrumentation is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The allowed Completion Time of 4 hours is based on operating experience to reduce THERMAL POWER to < 25% RTP from full power conditions in an orderly manner and without challenging plant systems.

If the failure only affects the trip function of a single main feed pump, an option is always available to remove the affected component from service and restore OPERABILITY. This is acceptable because removing the component from service performs the safety function.

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 feedwater - main turbine high water level trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions

(continued)

BASES

BACKGROUND (continued)

(2) The closing of two Turbine Stop Valves may or may not cause an RPT trip depending on which stop valves are closed.

(3) The closing of three or more Turbine Stop Valves will always yield an RPT trip.

If either trip system actuates, both recirculation pumps will trip. There are two RPT breakers in series per recirculation pump. One trip system trips one of the two RPT breakers for each recirculation pump, and the second trip system trips the other RPT breaker for each recirculation pump.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The TSV—Closure and the TCV Fast Closure, Trip Oil Pressure—Low Functions are designed to trip the recirculation pumps in the event of a turbine trip or generator load rejection to mitigate the neutron flux, heat flux, and 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 take credit for EOC-RPT, are summarized in References 2 and 3.

To mitigate pressurization transient effects, the EOC-RPT must trip the recirculation pumps after initiation of 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 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 < 30% RTP. 26

EOC-RPT instrumentation satisfies Criterion 3 of the NRC Policy Statement. (Ref. 6)

The OPERABILITY of the EOC-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.1.2. The actual setpoint is calibrated consistent with applicable

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Turbine Stop Valve—Closure

Closure of the TSVs and a main turbine trip result 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 TSV—Closure in anticipation of the transients that would result from closure of these valves. EOC-RPT decreases reactor power and aids the reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient. Closure of the TSVs is determined by measuring the position of each valve. There are two separate position switches associated with each stop valve, the signal from each switch being assigned to a separate trip channel. The logic for the TSV—Closure Function is such that two or more TSVs must be closed to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ 30% RTP. This is accomplished automatically by pressure instruments sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this function nonconservatively (THERMAL POWER is derived from first stage pressure), the main turbine bypass valves must not cause the trip Functions to be bypassed when thermal power is ≥ 30% 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 Allowable Value is selected to detect imminent TSV closure.

26

This protection is required, consistent with the safety analysis assumptions, whenever THERMAL POWER is ≥ 30% RTP. Below 30% RTP, 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.

Turbine Control Valve 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

reactor scram in ensuring that the MCPR SL is not exceeded during the worst case transient.

Fast closure of the TCVs is determined by measuring the electrohydraulic control fluid pressure at each control valve. There is one pressure instrument associated with each control valve, and the signal from each instrument 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 instrument trips) to produce an EOC-RPT. This Function must be enabled at THERMAL POWER ≥ 30% RTP. This is accomplished automatically by pressure instruments sensing turbine first stage pressure. Because an increase in the main turbine bypass flow can affect this function nonconservatively (THERMAL POWER is derived from first stage pressure) the main turbine bypass valves must not cause the trip Functions to be bypassed when thermal power is ≥ 30% RTP. Four channels of TCV Fast Closure, Trip Oil Pressure—Low, 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 TCV Fast Closure, Trip Oil Pressure—Low Allowable Value is selected high enough to detect imminent TCV ~~fast closure~~.

26

≥26 26

This protection is required consistent with the safety analysis whenever THERMAL POWER is ≥ 30% RTP. Below 30% RTP, 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.

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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

capability when 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. This requires two channels of the Function in the same trip system, to each be OPERABLE or in trip, and the associated RPT breakers to be OPERABLE or in trip. Alternately, 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 time 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 for Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1 and C.2

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With any Required Action and associated Completion Time not met, THERMAL POWER must be reduced to < 30% RTP within 4 hours. Alternately, the associated recirculation pump 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 < 30% RTP from full power conditions in an orderly manner and without challenging plant systems.

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. 4) assumption of the average

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1.2 (continued)

The Frequency is based upon the assumption of an 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.4.1.3

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(s) would also be inoperable.

The 24 month Frequency is based on the need to perform portions of this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

SR 3.3.4.1.4

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This SR ensures that an EOC-RPT initiated from the TSV—Closure and TCV Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 30% RTP. This is performed by a Functional check that ensures the EOC-RPT Function is not bypassed. Because increasing the main turbine bypass flow can affect this function nonconservatively (THERMAL POWER is derived from first stage pressure) the main turbine bypass valves must not cause the trip Functions to be bypassed when thermal power is ≥ 30% RTP. If any functions are bypassed at ≥ 30% RTP, either due to open main turbine bypass valves or other reasons, the affected TSV—Closure and TCV Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.b. Main Steam Line Pressure—Low

Low MSL pressure indicates that there may be a problem with the turbine pressure regulation, which could result in a low reactor vessel water level condition and the RPV cooling down more than 100°F/hr if the pressure loss is allowed to continue. The Main Steam Line Pressure—Low Function is directly assumed in the analysis of the pressure regulator failure (Ref. 2). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hr) 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 psig, which results in a scram due to MSIV closure, thus reducing reactor power to < ~~25~~% RTP.) 23

The MSL low pressure signals are initiated from four instruments ~~that are~~ connected to the MSL header. The instruments are arranged such that, even though physically separated from each other, each instrument 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 Main Steam Line Pressure—Low trip will only occur after a 500 millisecond time delay to prevent any spurious isolations.

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).

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) (Ref. 1). The isolation action, along with the scram function of the Reactor Protection System (RPS), ensures that the fuel peak

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1 (continued)

drive flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship indicates a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, loop drive flow versus pump speed relationship must be verified.

Individual jet pumps in a recirculation loop normally 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 timely for detecting jet pump degradation and is consistent with the Surveillance Frequency for recirculation loop OPERABILITY verification.

This SR is modified by two Notes. If this SR has not been performed in the previous 24 hours at the time an idle recirculation loop is restored to service, Note 1 allows 4 hours after the idle recirculation loop is in operation before the SR must be completed because these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions and complete data collection and evaluation.

Note 2 allows deferring completion of this SR until 24 hours after THERMAL POWER is greater than 25% of RTP. During low flow conditions, jet pump noise approaches the threshold

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(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of S/RVs are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB). 14

The S/RVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. There are a total of 16 S/RVs of which any ~~12~~ are required to be OPERABLE. The S/RVs can actuate by either of two modes: the safety mode or the relief mode. In the safety mode (or spring mode of operation), the valve opens when steam pressure at the valve inlet overcomes the spring force holding the valve closed. This satisfies the Code requirement.

Each S/RV discharges steam through a discharge line to a point below the minimum water level in the suppression pool. Six S/RVs also serve as the Automatic Depressurization System (ADS) valves. The ADS requirements are specified in LCO 3.5.1, "ECCS—Operating."

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressurization 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. 1). For the purpose of the analyses, ~~12~~ of the 16 S/RVs are assumed to operate 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.

14

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above. Reference 2 discusses additional events that are expected to actuate the S/RVs.

S/RVs satisfy Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

14

The safety function of ~~12~~ of the 16 S/RVs are required to be OPERABLE to satisfy the assumptions of the safety analysis (Refs. 1 and 2). The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety function).

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

Operation with fewer valves OPERABLE than specified, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded.

APPLICABILITY

In MODES 1, 2, and 3, all required S/RVs must be OPERABLE, since considerable energy may be in the reactor core and the limiting design basis transients are assumed to occur in these MODES. The S/RVs may be required to provide pressure relief to discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of dissipating the core heat.

In MODE 4 reactor pressure is low enough that the overpressure limit is unlikely to be approached by assumed

(continued)

BASES

APPLICABILITY (continued)	operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The S/RV function is not needed during these conditions.

ACTIONS

A.1 and A.2

With less than the minimum number of required S/RVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If the safety function of one or more required S/RVs is inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENT

SR 3.4.3.1

The Surveillance requires that the required S/RVs will open at the pressures assumed in the safety analysis of Reference 1. The demonstration of the S/RV safe lift settings must be performed during shutdown, since this is a bench test, to be done in accordance with the Inservice Testing Program. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures. The S/RV setpoint is ±3% of the nominal setpoint for OPERABILITY. Requirements for accelerated testing are established in accordance with the Inservice Test Program. Any of the 16 S/RVs, identified in this Surveillance Requirement, with their associated setpoints, can be designated as the ~~12~~ required S/RVs. This maintains the assumptions in the overpressure analysis. 14

A Note is provided to allow up to two of the required ~~12~~ S/RVs to be physically replaced with S/RVs with lower setpoints until the next refueling outage. This provides operational flexibility which maintains the assumptions in the over-pressure analysis.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.10.5 and SR 3.4.10.6

Differential temperatures within the applicable limits ensure that thermal stresses resulting from increases in THERMAL POWER or recirculation loop flow during single recirculation loop operation will not exceed design allowances. Performing the Surveillance within 15 minutes before beginning such an increase in power or flow rate provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the change in operation.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.10.6 is to compare the temperatures of the operating recirculation loop and the idle loop.

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Plant specific startup test data has determined that the bottom head is not subject to temperature stratification at power levels ≥ ~~30~~% of RTP and with single loop flow rate ≥ 21,320 gpm (50% of rated loop flow). Therefore, SR 3.4.10.5 and SR 3.4.10.6 have been modified by a Note that requires the Surveillance to be met only under these conditions. The Note for SR 3.4.10.6 further limits the requirement for this Surveillance to exclude comparison of the idle loop temperature if the idle loop is isolated from the RPV since the water in the loop can not be introduced into the remainder of the Reactor Coolant System.

SR 3.4.10.7, SR 3.4.10.8, and SR 3.4.10.9

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits during system heatup and cooldown. However, operations approaching MODE 4 from MODE 5 and in MODE 4 with RCS temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO limits.

The flange temperatures must be verified to be above the limits 30 minutes before and while tensioning the vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When in MODE 4 with RCS temperature ≤ 80°F, 30 minute checks of the flange temperatures are required because of the reduced margin to the limits. When in MODE 4 with RCS temperature ≤ 100°F, monitoring of the flange temperature is required every 12 hours to ensure the temperature is within the specified limits.

The 30 minute Frequency reflects the urgency of maintaining the temperatures within limits, and also limits the time that the temperature limits could be exceeded. The 12 hour Frequency is reasonable based on the rate of temperature change possible at these temperatures.

(continued)

BASES (continued)

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 1.0% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 45 psig. 48.6

Primary containment satisfies Criterion 3 of the NRC Policy Statement. (Ref. 6)

LCO

Primary containment OPERABILITY is maintained by limiting leakage to ≤1.0 L_a, except prior to each startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time, applicable leakage limits must be met. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analyses.

Individual leakage rates specified for the primary containment air lock are addressed in LCO 3.6.1.2.

Leakage requirements for MSIVs and Secondary containment bypass are addressed in LCO 3.6.1.3.

(continued)

BASES (continued)

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 1.0% by weight of the containment air per 24 hours at the calculated maximum peak containment pressure (P_a) of 45 psig (Ref. 3). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock. 48.6

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.

The primary containment air lock satisfies Criterion 3 of the NRC Policy Statement. (Ref. 4)

LCO

As part of primary containment pressure boundary, 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 lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be opened at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry or exit from primary containment.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.9 (continued)

detected at the earliest possible time. EFCV failures will be evaluated to determine if additional testing in that test interval is warranted to ensure overall reliability and that failures to isolate are very infrequent. Therefore, testing of a representative sample was concluded to be acceptable from a reliability standpoint (Reference 7).

SR 3.6.1.3.10

The TIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired. The Frequency of 24 months on a STAGGERED TEST BASIS is considered adequate given the administrative controls on replacement charges and the frequent checks of circuit continuity (SR 3.6.1.3.4).

SR 3.6.1.3.11

This SR ensures that the leakage rate of secondary containment bypass leakage paths is less than the specified leakage rate. This provides assurance that the assumptions in the radiological evaluations of Reference 4 are met. The secondary containment leakage pathways and Frequency are defined by the Primary Containment Leakage Rate Testing Program. This SR simply imposes additional acceptance criteria. 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 MODES, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required.

SR 3.6.1.3.12

The analyses in References 1 and 4 are based on the specified leakage rate. Leakage through each MSIV must be ≤ 100 scfh for anyone MSIV or ≤ 300 scfh for total leakage through the MSIVs combined with the Main Steam Line Drain Isolation Valve, HPCI Steam Supply Isolation Valve and the RCIC Steam Supply Isolation Valve. The MSIVs can be tested at either ≥ Pt (22.5 psig) or P_a (45 psig). Main Steam Line Drain Isolation, HPCI and RCIC Steam Supply Line Isolation Valves, are tested at P_a (45 psig). 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

and

24.3

48.6

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.12 (continued)

conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required. The Frequency is required by the Primary Containment Leakage Rate Testing Program. If leakage from the MSIVs requires internal work on any MSIV, the leakage will be reduced for the affected MSIV to ≤ 11.5 scfh.

SR 3.6.1.3.13

53.46

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of Reference 2 are met. The acceptance criteria for the combined leakage of all hydrostatically tested lines is 3.3 gpm when tested at 1.1 P_a, (49.5 psig). The combined leakage rates must be demonstrated in accordance with the leakage rate test Frequency required by the Primary Containment Leakage Testing Program.

As noted in Table B 3.6.1.3-1, PCIVs associated with this SR are not Type C tested. Containment bypass leakage is prevented since the line terminates below the minimum water level in the suppression chamber. These valves are tested in accordance with the IST Program. Therefore, these valves leakage is not included as containment leakage.

This SR has been modified by a Note that states that 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 pressurized and primary containment is required. In some instances, the valves are required to be capable of automatically closing during MODES other than MODES 1, 2, and 3. However, specific leakage limits are not applicable in these other MODES or conditions.

REFERENCES

1. FSAR, Chapter 15.
2. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).
3. 10 CFR 50, Appendix J, Option B.
4. FSAR, Section 6.2.
5. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operations to preserve the initial conditions assumed in the accident analysis for a Design Basis Accident (DBA) or loss of coolant accident (LOCA).

APPLICABLE SAFETY ANALYSES

Primary containment performance is evaluated for the entire spectrum of break sizes for postulated LOCAs (Ref. 1). Among the inputs to the DBA is the initial primary containment internal pressure (Ref. 1). Analyses assume an initial containment pressure of -1.0 to 2.0 psig. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA containment internal pressure does not exceed the maximum allowable.

The maximum calculated containment pressure occurs during the reactor blowdown phase of the DBA, which assumes an instantaneous recirculation line break. The calculated peak containment pressure for this limiting event is 44.8 psig (Ref. 1). 48.6

The minimum containment pressure occurs during an inadvertent spray actuation. The calculated minimum drywell pressure for this limiting event is -4.72 psig. (Ref. 1)

Containment pressure satisfies Criterion 2 of the NRC Policy Statement. (Ref. 2)

LCO

In the event of a DBA, with an initial containment pressure -1.0 to 2.0 psig, the resultant peak containment accident pressure will be maintained below the containment design pressure. The containment pressure is defined to include both the drywell pressure and the suppression chamber pressure. (Ref. 1)

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.1 Residual Heat Removal Service Water (RHRSW) System and the Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The RHRSW System is designed to provide cooling water for the Residual Heat Removal (RHR) System heat exchangers, required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The RHRSW System is operated whenever the RHR heat exchangers are required to operate in the shutdown cooling mode or in the suppression pool cooling or spray mode of the RHR System.

The RHRSW System consists of two independent and redundant subsystems. Each subsystem is made up of a header, one pump, a suction source, valves, piping, heat exchanger, and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity to maintain safe shutdown conditions. The two subsystems are separated so that failure of one subsystem will not affect the OPERABILITY of the other subsystem. One Unit 1 RHRSW subsystem and the associated (same division) Unit 2 RHRSW subsystem constitute a single RHRSW loop. The two RHRSW pumps in a loop can each, independently, be aligned to either Unit's heat exchanger. The RHRSW System is designed with sufficient redundancy so that no single active component failure can prevent it from achieving its design function. The RHRSW System is described in the FSAR, Section 9.2.6, Reference 1.

Cooling water is pumped by the RHRSW pumps from the UHS through the tube side of the RHR heat exchangers. After removing heat from the RHRSW heat exchanger, the water is discharged to the spray pond (UHS) by way of the UHS return loops. The UHS return loops direct the return flow to a network of sprays that dissipate the heat to the atmosphere or directly to the UHS via a bypass ~~valve.~~ header.

The system is initiated manually from the control room~~.~~ The system can be started any time the LOCA signal is manually overridden or clears.

except for the spray array bypass manual valves that are operated locally in the event of a failure of the spray array bypass valves.

(continued)

BASES (continued)

BACKGROUND (continued)

The ultimate heat sink (UHS) system is composed of a 350,000 cubic foot spray pond and associated piping and spray risers. Each UHS return loop contains a bypass line, a large spray array and a small spray array. The purpose of the UHS is to provide both a suction source of water and a return path for the RHRSW and ESW systems. The function of the UHS is to provide water to the RHRSW and ESW systems at a temperature less than the 97°F design temperature of the RHRSW and ESW systems. UHS temperature is maintained less than the design temperature by introducing the hot return fluid from the RHRSW and ESW systems into the spray loops and relying on spray cooling to maintain temperature. The UHS is designed to supply the RHRSW and ESW systems with all the cooling capacity required during a combination LOCA/LOOP for thirty days without fluid addition. The UHS is described in the FSAR, Section 9.2.7 (Reference 1).

APPLICABLE SAFETY ANALYSES

The RHRSW System removes heat from the suppression pool to limit the suppression pool temperature and primary containment pressure following a LOCA. This ensures that the primary containment can perform its function of limiting the release of radioactive materials to the environment following a LOCA. The ability of the RHRSW System to support long term cooling of the reactor or primary containment is discussed in the FSAR, Chapters 6 and 15 (Refs. 2 and 3, respectively). These analyses explicitly assume that the RHRSW System will provide adequate cooling support to the equipment required for safe shutdown. These analyses include the evaluation of the long term primary containment response after a design basis LOCA.

The safety analyses for long term cooling were performed for various combinations of RHR System failures. ~~The worst case single failure that would affect the performance of the RHRSW System is any failure that would disable one UHS return loop. The failure of the spray array bypass valve to close results in the inability of one UHS return loop to perform its design function because failure of this valve to close results in inadequate spray nozzle pressures on the affected loop.~~ As discussed in the FSAR, Section ~~6.2.2 (Ref. 2) for these analyses~~, manual initiation of the OPERABLE RHRSW subsystem and the associated RHR System is assumed to occur 30 minutes after a DBA. In this case, the maximum suppression chamber water temperature and pressure are analyzed to be below the design temperature of 220°F and maximum allowable pressure of 53 psig.

(continued)

Insert B 3.7-3A

BASES (continued)

APPLICABLE SAFETY ANALYSES (continued)

~~The failure of the large spray array valve to open on demand is of less consequence than the failure of the spray array bypass valve because the small spray array is still available. Two small spray arrays have the same capacity and can perform the same function as a single large spray array. Each small array can effectively discharge the output of one RHRSW subsystem and one ESW loop to the UHS. The small spray arrays do not meet the 10CFR50.36 criteria for inclusion into the Technical Specifications and are not included. As a result, no credit is taken for the existence of the small spray arrays.~~

The RHRSW System, together with the UHS, satisfy Criterion 3 of the NRC Policy Statement. (Ref. 4)

LCO

Two RHRSW subsystems are required to be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, assuming the worst case single active failure occurs coincident with the loss of offsite power.

An RHRSW subsystem is considered OPERABLE when:

a. One pump is OPERABLE; and

b. An OPERABLE flow path is capable of taking suction from the UHS and transferring the water to the RHR heat exchanger and returning it to the UHS at the assumed flow rate, and

c. An OPERABLE UHS.

The OPERABILITY of the UHS is based on having a minimum water level at the overflow weir of 678 feet 1 inch above mean sea level and a maximum water temperature of 85°F; unless either unit is in MODE 3. If a unit enters MODE 3, the time of entrance into this condition determines the appropriate maximum ultimate heat sink fluid temperature. If the earliest unit to enter MODE 3 has been in that condition for less than twelve (12) hours, the peak temperature to maintain OPERABILITY of the ultimate heat sink remains at 85°F. If either unit has been in MODE 3 for more than twelve (12) hours but less than twenty-four (24) hours, the OPERABILITY temperature of the ultimate heat sink becomes 87°F. If either unit has been in MODE 3 for twenty-four (24) hours or more, the OPERABILITY temperature of the ultimate heat sink becomes 88°F.

(continued)

<u>Insert B 3.7-3A</u>

The UHS design takes into account the cooling efficiency of the spray arrays and the evaporation losses during design basis environmental conditions. The spray array bypass header provides the flow path for the ESW and RHRSW system to keep the spray array headers from freezing. The small and/or large spray arrays are placed in service to dissipate heat returning from the plant. The UHS return header is comprised of the spray array bypass header, the large spray array, and the small spray array.

The spray array bypass header is capable of passing full flow from the RHRSW and ESW systems in each loop. The large spray array is capable of passing full flow from the RHRSW and ESW systems in each loop. The small spray array supports heat dissipation when low system flows are required.

BASES (continued)

Insert B 3.7-5A

ACTIONS (continued)

A.1

~~With one spray array bypass valve inoperable (that is, not capable of being closed on demand), or with one large spray array valve not capable of being opened, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the spray cooling function of the affected UHS return loop. As a result, the associated RHRSW subsystems must be declared inoperable.~~

A.2

Insert B3.7-5B

~~With one spray array bypass valve or one large spray array valve inoperable, only one large spray array is available for effective spray cooling. Failure of either the spray bypass valve or the large spray array valve in the unaffected loop would result in insufficient spray cooling capacity. The 72-hour~~ completion time is based on the fact that, although adequate UHS spray loop capability exists during this time period, both units are affected and an additional single failure results in a system configuration that will not meet design basis accident requirements.

If an additional RHRSW subsystem on either Unit is inoperable, cooling capacity less than the minimum required for response to a design basis event would exist. Therefore, an 8-hour Completion Time is appropriate. The 8-hour Completion Time provides sufficient time to restore inoperable equipment and there is a low probability that a design basis event would occur during this period.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if one Unit 2 RHRSW subsystem is inoperable. Although designated and operated as a unitized system, the associated Unit 1 subsystem is directly connected to a common header which can supply the associated RHR heat exchanger in either unit. The Unit 1 subsystems are considered capable of supporting Unit 2 RHRSW subsystem when the Unit 1 subsystem is OPERABLE and can provide the assumed flow to the Unit 2 heat exchanger. A Completion time of 72 hours, when one Unit 1 RHRSW subsystem is not capable of supporting the Unit 2 RHRSW subsystems, is allowed to restore the Unit 2 RHRSW subsystem to OPERABLE status. In this configuration, the remaining OPERABLE Unit 2 RHRSW subsystem is adequate to perform the RHRSW heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE RHRSW subsystem

(continued)

Insert B 3.7-5A

With one spray array loop bypass valve not capable of being closed on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the spray cooling function of the affected UHS return loop. As a result, the associated RHRSW subsystem must be declared inoperable.

With one spray array loop bypass valve not capable of being opened on demand, the associated Unit 1 and Unit 2 RHRSW subsystems and ESW subsystem are not provided a return path to the UHS. As a result, the associated RHRSW subsystems and ESW subsystem must be declared inoperable.

With one spray array bypass manual valve not capable of being closed, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the spray cooling function of the affected UHS return path if the spray array bypass valve fails to close. As a result, the associated RHRSW subsystems must be declared inoperable.

With one spray array bypass manual valve not open, the associated Unit 1 and Unit 2 RHRSW subsystems and ESW subsystem are not provided a return path to the UHS. As a result, the associated RHRSW subsystems and ESW subsystem must be declared inoperable.

With one large spray array valve not capable of being opened on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the full required spray cooling capability of the affected UHS return path. With one large spray array valve not capable of being closed on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the small spray array when loop flows are low as the required spray nozzle pressure is not achievable for the small spray array. As a result, the associated RHRSW subsystems must be declared inoperable.

With one small spray array valve not capable of being opened on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the spray cooling function of the affected UHS return path for low loop flow rates. For a single failure of the large spray array valve in the closed position, design bases LOCA/LOOP calculations assume that flow is reduced on the affected loop within 3 hours after the event to allow use of the small spray array. With one small spray array valve not capable of being closed on demand, the associated Unit 1 and Unit 2 RHRSW subsystems cannot use the large spray array for a flow path as the required nozzle pressure is not achievable for the large spray array. As a result, the associated RHRSW subsystems must be declared inoperable.

Insert B 3.7-5B

With any UHS return path valve listed in Tables 3.7.1-1, 3.7.1-2, or 3.7.1-3 inoperable, the UHS return path is no longer single failure proof.

BASES (continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.1.5

UHS return header

The ~~return loop~~ large spray array valves are required to open in order for the UHS to perform its design function. These valves are manually actuated from either the control room or the remote shutdown panel, under station operating procedure, when the RHRSW system is required to remove energy from the reactor vessel or suppression pool. A large spray array valve is considered inoperable if it cannot be opened on demand, because the valve must be opened to allow spray cooling to occur. This SR demonstrates that the valves will move to their required positions when required. The 92-day Test Frequency is based upon engineering judgement and operating/testing history that indicates this frequency gives adequate assurance that the valves will move to their required positions when required.

REFERENCES

1. FSAR, Section 9.2.6.
2. FSAR, Chapter 6.
3. FSAR, Chapter 15.
4. Final Policy Statement on Technical Specifications Improvements, July 22, 1993 (58 FR 39132).

Insert B 3.7-6c A

Insert B 3.7-6cA

SR 3.7.1.6

The small spray array valves HV-012224A2 and B2 are required to be closed in order for the UHS to perform its design function. These valves are manually actuated from the control room or the remote shutdown panel, under station operating procedure, when the RHRSW system is required to remove energy from the reactor vessel or suppression pool. A small spray array valve is considered inoperable if it cannot be closed when required to support design bases analyses lineups. The small spray array valve has to be closed for the large spray array to be capable of design bases cooling capacity. This SR demonstrates that the valves will move to their required positions when required. The 92-day Test Frequency is based upon engineering judgment and operating/testing history that indicates this frequency gives adequate assurance that the valves will move to their required positions when required.

SR 3.7.1.7

The spray array bypass manual valves 012287A and B are required to be closed in the event of a failure of the spray array bypass valves to close in order for the UHS to perform its design function. A spray array bypass manual valve is considered inoperable if it is not capable of being closed in a timely manner as described in the design bases analyses (3 hours from the time the spray array bypass valve fails to close and the UHS temperature exceeds the requirements in SR 3.7.1.2.)

B 3.7 PLANT SYSTEMS

B 3.7.2 Emergency Service Water (ESW) System

BASES

BACKGROUND

The ESW System is designed to provide cooling water for the removal of heat from equipment, such as the diesel generators (DGs), residual heat removal (RHR) pump coolers, and room coolers for Emergency Core Cooling System equipment, required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. Upon receipt of a loss of offsite power or loss of coolant accident (LOCA) signal, ESW pumps are automatically started after a time delay.

The ESW System consists of two independent and redundant subsystems. Each of the two ESW subsystems is made up of a header, two pumps, a suction source, valves, piping and associated instrumentation. The two subsystems are separated from each other so an active single failure in one subsystem will not affect the OPERABILITY of the other subsystem. A continuous supply of water is provided to ESW from the Service Water System for the keepfill system. This supply is not required for ESW operability.

Cooling water is pumped from the Ultimate Heat Sink (UHS) by the ESW pumps to the essential components through the two main headers. After removing heat from the components, the water is discharged to the spray pond (UHS) by way of a network of sprays that dissipate the heat to the atmosphere or directly to the UHS via a bypass ~~valve.~~ header

APPLICABLE SAFETY ANALYSES

Sufficient water inventory is available for all ESW System post LOCA cooling requirements for a 30 day period with no additional makeup water source available. The ability of the ESW System to support long term cooling is assumed in evaluations of the equipment required for safe reactor shutdown presented in the FSAR, Chapters 4 and 6 (Refs. 1 and 2, respectively).

The ability of the ESW System to provide adequate cooling to the identified safety equipment is an implicit assumption for the safety analyses evaluated in References 1 and 2. The ability to provide onsite emergency AC power is dependent on the ability of the ESW System to cool the DGs. The long term cooling capability of the RHR and core spray pumps is also dependent on the cooling provided by the ESW System.

The ESW System satisfies Criterion 3 of the NRC Policy Statement. (Ref. 3)

(continued)

BASES

LCO

The ESW subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one does not depend on the other. In the event of a DBA, one subsystem of ESW is required to provide the minimum heat removal capability assumed in the safety analysis for the system to which it supplies cooling water. To ensure this requirement is met, two subsystems of ESW must be OPERABLE. At least one subsystem will operate, if the worst single active failure occurs coincident with the loss of offsite power.

A subsystem is considered OPERABLE when it has two OPERABLE pumps, and an OPERABLE flow path capable of taking suction from the UHS and transferring the water to the appropriate equipment and returning flow to the UHS. If individual loads are isolated, the affected components may be rendered inoperable, but it does not necessarily affect the OPERABILITY of the ESW System. Because each ESW subsystem supplies all four required DGs, an ESW subsystem is considered OPERABLE if it supplies at least three of the four DGs provided no single DG does not have an ESW subsystem capable of supplying flow.

An adequate suction source is not addressed in this LCO since the minimum net positive suction head of the ESW pumps is bounded by the Residual Heat Removal Service Water System requirements (LCO 3.7.1, "Residual Heat Removal System and Ultimate Heat Sink (UHS)").

The ESW return loop requirement, in terms of operable UHS return paths or UHS spray capacity, is also not addressed in this LCO. UHS operability, in terms of the return loop and spray capacity is addressed in the RHRSW/ UHS Technical Specification (LCO 3.7.1, "Residual Heat Removal Service Water System and Ultimate Heat Sink (UHS)). ~~The design basis calculations for the UHS assume post-accident ESW return flow through the spray bypass valve on one return loop until a UHS temperature is reached whereby realignment of appropriate ESW heat loads to the spray loop is required. This realignment is manual and can be done several hours or more after accident initiation.~~

APPLICABILITY

In MODES 1, 2, and 3, the ESW System is required to be OPERABLE to support OPERABILITY of the equipment serviced by the ESW System. Therefore, the ESW System is required to be OPERABLE in these MODES.

In MODES 4 and 5, the OPERABILITY requirements of the ESW System is determined by the systems it supports.

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Turbine Bypass System

BASES

23

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 full bypass capacity of the system is approximately ~~25%~~ 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 Main Turbine Bypass System consists of five valves connected to the main steam lines between the main steam isolation valves and the turbine stop valve bypass valve chest. Each of these five valves is operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Electro Hydraulic Control System, as discussed in the FSAR, Section 7.7.1.5 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves that direct all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows from the bypass chest, through connecting piping, to the pressure breakdown assemblies, where a series of orifices are used to further reduce the steam pressure before the steam enters the condenser.

APPLICABLE SAFETY ANALYSES

The Main Turbine Bypass System has two modes of operation. A fast opening mode is assumed to function during the turbine generator load rejection, turbine trip, and feedwater controller failure transients as discussed in FSAR Sections 15.2.2, 15.2.3, and 15.1.2 (Refs. 2, 3, and 4). A pressure regulation mode is assumed to function during the control rod withdrawal error and recirculation flow controller failure transients as discussed in FSAR Sections 15.4.2 and 15.4.5 (Refs. 5 and 6). Both modes of operation are assumed to function for all bypass valves assumed in the applicable safety analyses. Opening the bypass valves during the above transients mitigates the increase in reactor vessel pressure, which affects both MCPR and LHGR during the event. An inoperable Main Turbine Bypass System may result in a MCPR and / or LHGR penalty.

The Main Turbine Bypass System satisfies Criterion 3 of the NRC Policy Statement. (Ref. 7)

(continued)

BASES (continued)

LCO

The Main Turbine Bypass System fast opening and pressure regulation modes are required to be OPERABLE to limit the pressure increase in the main steam lines and reactor pressure vessel during transients that cause a pressurization so that the Safety Limit MCPR and LHGR are not exceeded. With the Main Turbine Bypass System inoperable, modifications to the MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and LHGR limits (LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)") may be applied to allow this LCO to be met. The MCPR and LHGR limits for the inoperable Main Turbine Bypass System are specified in the COLR. An OPERABLE Main Turbine Bypass System requires the bypass valves to open in response to increasing main steam line pressure. Licensing analyses credit an OPERABLE Main Turbine Bypass System as having both the bypass valve fast opening mode and pressure regulation mode. The fast opening mode is required for transients initiated by a turbine control valve or turbine stop valve closure. The pressure regulation mode is required for transients where the power increase exceeds the capability of the turbine control valves.

The cycle specific safety analyses assume a certain number of OPERABLE main turbine bypass valves as an input (i.e., one through five). Therefore, the Main Turbine Bypass System is considered OPERABLE when the number of OPERABLE bypass valves is greater than or equal to the number assumed in the safety analyses. The number of bypass valves assumed in the safety analyses is specified in the COLR. This response is within the assumptions of the applicable analysis (Refs. 2 – 6).

23

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at ≥ 25% RTP to ensure that the fuel cladding integrity Safety Limit ~~is~~ not violated during all applicable transients. As discussed in the ~~Bases for~~ LCOs 3.2.2 and 3.2.3, *sufficient margin to these limits exists at* < 25% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If the Main Turbine Bypass System is inoperable and the MCPR and LHGR limits for an inoperable Main Turbine Bypass System, as specified in the COLR, are not applied, the assumptions of the design basis transient analysis may not be met.

(continued)

BASES

ACTIONS

A.1 (continued)

Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status or adjust the MCPR and LHGR 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 the Main Turbine Bypass System.

B.1

23

If the Main Turbine Bypass System cannot be restored to OPERABLE status or the MCPR and LHGR limits for an inoperable Main Turbine Bypass System are not applied, THERMAL POWER must be reduced to < 25% RTP. As discussed in the Applicability section, operation at < 25% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the applicable transients. 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 3.7.6.1

Cycling each required main turbine bypass valve through one complete cycle of full travel (including the fast opening feature) 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. Operating experience has shown that these components usually pass the SR when performed at the 31 day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.6.2

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 (simulate automatic actuation), the valves will actuate to their required position. The 24 month Frequency is based on the need to

(continued)

B 3.7 PLANT SYSTEMS

B 3.7.8 Main Turbine Pressure Regulation System

BASES

BACKGROUND

The Main Turbine Pressure Regulation System is designed to control main steam pressure. The Main Turbine Pressure Regulation System contains two pressure regulators which are provided to maintain primary system pressure control. They independently sense pressure just upstream of the main turbine stop valves and compare it to two separate setpoints to create proportional error signals that produce each regulator's output. The outputs of both regulators feed into a high value gate. The regulator with the highest output controls the main turbine control valves. The lowest pressure setpoint gives the largest pressure error and thereby the largest regulator output. The backup regulator is nominally set 3 psi higher giving a slightly smaller error and a slightly smaller effective output of the controller. The main turbine pressure regulation function of the Turbine Electro Hydraulic Control System is discussed in the FSAR, Sections 7.7.1.5 (Ref. 1) and 15.2.1 (Ref. 2).

APPLICABLE SAFETY ANALYSES

A downscale failure of the primary or controlling pressure regulator as discussed in FSAR, Section 15.2.1 (Ref. 2) will cause the turbine control valves to begin to close momentarily. The pressure will increase, because the reactor is still generating the initial steam flow. The backup regulator will reposition the valves and re-establish steady-state operation above the initial pressure equal to the setpoint difference which is nominally 3 psi. Provided that the backup regulator takes control, the disturbance is mild, similar to a pressure setpoint change and no significant reduction in fuel thermal margins occur.

Failure of the backup pressure regulator is also discussed in FSAR, Section 15.2.1. If the backup pressure regulator fails downscale or is out of service when the primary regulator fails downscale, the turbine control valves (TCVs) will close in the servo or normal operating mode. Since the TCV closure is not a fast closure, there is no loss of EHC pressure to provide an anticipatory scram. The reactor pressure will increase to the point that a high neutron flux or a high reactor pressure scram is initiated to shut down the reactor. The increase in flux and pressure affects both MCPR and LHGR during the event. An inoperable Main Turbine Pressure Regulation System may result in a MCPR and / or LHGR penalty.

The Main Turbine Pressure Regulation System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

(continued)

BASES (continued)

ACTIONS

B.1

If the Main Turbine Pressure Regulation System cannot be restored to OPERABLE status or the MCPR and LHGR limits for an inoperable Main Turbine Pressure Regulation System are not applied, THERMAL POWER must be reduced to < 23% RTP. As discussed in the Applicability section, operation at < 23% RTP results in sufficient margin to the required limits, and the Main Turbine Pressure Regulation System is not required to protect fuel integrity during the applicable transients.

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 3.7.8.1

Verifying that both Main Turbine Pressure Regulators can be independently used to control pressure demonstrates that the Main Turbine Pressure Regulation System is OPERABLE and will function as required. The 92-day Frequency is based on engineering judgment, is consistent with the procedural controls governing pressure regulator operation, and ensures proper control of main turbine pressure. Operating experience has shown that these components usually pass the SR when performed at the 92-day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.8.2

The Main Turbine Pressure Regulators are designed so that a downscale failure of the controlling regulator will result in the backup regulator automatically assuming control. This SR demonstrates that, with the failure of the controlling pressure regulator, the backup pressure regulator will assume control. The 24-month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage or unit start-up and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 24-month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

(continued)

BASES

REFERENCES

1. FSAR, Section 7.7.1.5.
2. FSAR, Section 15.2.1.

(continued)