ATTACHMENT 1

LICENSE AMENDMENT REQUEST
STRETCH POWER UPRATE

DESCRIPTIONS, TECHNICAL ANALYSIS AND REGULATORY ANALYSIS FOR THE PROPOSED OPERATING LICENSE AND TECHNICAL SPECIFICATIONS CHANGES

DOMINION NUCLEAR CONNECTICUT, INC.
MILLSTONE POWER STATION UNIT 3

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1.0 Introduction

Pursuant to 10 CFR 50.90, Dominion Nuclear Connecticut, Inc. (DNC) hereby requests to amend Operating License NPF-49 for Millstone Power Station Unit 3 (MPS3). This proposed stretch power uprate (SPU) License Amendment Request (LAR) would increase the unit's authorized core power level from 3411 megawatts thermal (MWt) to 3650 MWt, and make changes to Technical Specifications as necessary to support operation at the stretch power level. The SPU LAR does not rely on any previously submitted DNC LARs that are pending NRC approval.

2.0 Description of the Proposed Changes

The proposed changes involve one revision to the Operating License and several changes to the Technical Specifications. It also involves changes to the Licensing Basis (MPS3 FSAR) that will require prior NRC review and approval in accordance with 10 CFR 50.90. Each change is described below and evaluated in Technical Analysis, Section 5.0 of this attachment.

2.1 Operating License Change

Facility Operating License NPF-49, Paragraph 2C.(1), Maximum Power Level is changed to authorize operation at reactor core power levels not in excess of 3650 megawatts thermal.

2.2 Changes to Technical Specifications

The proposed Technical Specifications (TS) changes are specifically required as part of, or as a result of, the MPS3 SPU. No optional or unrelated Technical Specification changes are proposed in this License Amendment Request.

2.2.1 TS Definitions

Technical Specification 1.0, Paragraph 1.27, "RATED THERMAL POWER", is changed from 3411 MWt to 3650 MWt.

2.2.2 TS 2.1.1.1 Safety Limits

Technical Specification 2.1.1.1 is revised as follows: The departure from nucleate boiling ratio limit is changed from 1.17 to 1.14, and DNB correlations WRB-1 and WRB-2 are replaced with WRB-2M.

2.2.3 TS Table 2.2-1, Reactor Trip System Instrumentation Trip Setpoints, Functional Unit 12, Reactor Coolant Flow-Low

Functional Unit 12, Reactor Coolant Flow-Low is revised from ‘loop design flow’ to ‘nominal loop flow’ and corresponding footnote is deleted. No change to the nominal trip setpoint or allowable value is proposed.

2.2.4 TS Table 2.2-1, Reactor Trip System Instrumentation Trip Setpoints, Functional Unit 18c, Power Range Neutron Flux, P-8

The Reactor Trip System Interlock- Power Range Neutron Flux, P-8 nominal trip setpoint is increased from 37.5% to 50.0% and Allowable Value is increased from ≤38.1% to ≤50.6% of RTP.

2.2.5 TS Table 2.2-1, Reactor Trip Instrumentation Trip Setpoints, Table Notations

As part of the OTΔT optimization, a 4-second filter is being added to the T_{hot} input, prior to the modules that calculate T_{avg} and ΔT, to smooth out temperature spikes observed in the T_{hot} signals. The filter allows additional optimization of the OTΔT/OPΔT settings to improve the trip margins for the OTΔT and OPΔT reactor trips, and also add stability to the rod control system. As a result, the rate lag compensator card for T_{avg} input to the OPΔT is being eliminated from the control system, and the second term (K5 term) in Note 3 equation for OPΔT is deleted.

2.2.6 TS 3/4.2.3 RCS Flow Rate and Nuclear Enthalpy Rise Hot Channel Factor

Technical Specification 3.2.3.1.a is revised as follows: the RCS total flow rate is revised from ≥ 371,920 gpm to ≥ 363,200 gpm.

The Surveillance Requirement 4.2.3.1.2 for determining RCS total flow rate and $F^N_{\Delta H}$ is being changed as follows.

The Surveillance Requirement 4.2.3.1.2 is broken into two parts, one for $F^N_{\Delta H}$ and other for the RCS total flow rate as follows:

SR 4.2.3.1.2 $F^N_{\Delta H}$ Shall be determined to be within the acceptable range:

a. Prior to operation above 75% of RATED THERMAL POWER after each fuel loading, and

b. At least once per 31 Effective Full Power Days.

SR 4.2.3.1.3 the RCS total flow rate shall be determined to be within the acceptable range by:

a. Verifying by precision heat balance that the RCS total flow rate is ≥ 363,200 gpm and greater than or equal to the limit specified in the COLR within 24 hours after reaching 90% of RATED THERMAL POWER after each fuel loading, and

b. Verifying that the RCS total flow rate is ≥ 363,200 gpm and greater than or equal to the limit specified in the COLR at least once per 12 hours.

It is noted that no technical changes are proposed for the measurement of $F^N_{\Delta H}$. Current Surveillance requirement 4.2.3.1.3 is being deleted because its requirement is included in the proposed Surveillance Requirement 4.2.3.1.3.b. Current Surveillance Requirement 4.2.3.1.2.b related to the measurement of the RCS total flow rate (at least once per 31 Effective Full Power Days) is deleted because it is enveloped by the proposed Surveillance Requirement 4.2.3.1.3.b. Surveillance Requirement 4.2.3.1.5 is deleted. The RCS total flow rate measurement requirement of the current Surveillance Requirement 4.2.3.1.5 is included in the proposed Surveillance Requirement 4.2.3.1.3. The current Surveillance Requirements 4.2.3.1.4 and 4.2.3.1.5 require that the measurement instrumentation be calibrated seven days prior to the performance of the flow measurements. This requirement is deleted from the Technical Specifications. In addition, Surveillance Requirement 4.2.3.1.6 is being deleted.

2.2.7 TS 3/4.3.2 Engineered Safety Features Actuation System Instrumentation

A new functional unit 11, 'Cold Leg Injection Permissive, P-19 ', is added to Table 3.3-3, Engineered Safety Features Actuation System Instrumentation, Table 3.3-4, Engineered Safety Features Actuation System Instrumentation Trip Setpoints and Table 4.3-2, Engineered Features Actuation System Instrumentation Surveillance Requirements. This permissive will be derived utilizing the existing low pressurizer pressure reactor trip 2/4 bistable trip logic and will be required to be operable during Modes 1, 2, and 3. ACTION 20 is applicable for an inoperable P-19 permissive. It has the same setpoint (1900 psia) and same allowable value (≥ 1897.6 psia) as that of the low pressurizer reactor trip. Surveillance requirements for this functional unit are added to Table 3.3-4.

In the asterisk note in TABLE NOTATIONS for Table 3.3-3 and Table 4.3-2, the Mode applicability is being changed to eliminate Modes 5 and 6. The new asterisk note will read:

- MODES 1, 2, 3, and 4.

- During fuel movement within containment or the spent fuel pool.

2.2.8 TS 3/4.4.4.3 Pressurizer

Figure 3.4-5 is being replaced by a new figure to reflect a new pressurizer level control program. This revised pressurizer level control program supports the revised transient analysis and accommodates Reactor Coolant System (RCS) shrink and swell at SPU conditions.

2.2.9 TS 3/4.7.1 Turbine Cycle

The following Action statements are replacing ACTION 'a' for Technical Specification 3.7.1.1:

a. With one or more steam generators (SGs) with one MSSV inoperable, and the Moderator Temperature Coefficient (MTC) zero or negative at all power levels, within 4 hours reduce THERMAL POWER to less than or equal to 60.1% RATED THERMAL POWER (RTP); otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With one or more SGs with two or more MSSVs inoperable, within 4 hours reduce THERMAL POWER to less than or equal to the maximum allowable % RTP specified in Table 3.7-1 for the number of OPERABLE MSSVs, and reduce the Power Range Neutron Flux High setpoint to less than or equal to the maximum allowable % RTP specified in Table 3.7-1 for number of OPERABLE MSSVs within the next 32 hours*; otherwise, be in least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With one or more SGs with one MSSV inoperable and the MTC positive at any power level, within 4 hours reduce THERMAL POWER to less than or equal to the maximum allowable % RTP specified in Table 3.7-1 for the number of OPERABLE MSSVs and reduce the Power Range Neutron Flux High setpoint to less than or equal to the maximum allowable % RTP specified in Table 3.7-1 for number of OPERABLE MSSVs within the next 32 hours*; otherwise, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

d. With one or more SGs with four or more MSSVs inoperable, be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

In addition, a note is being added to Action Statements that allows a separate condition entry into Action Statement for each inoperable MSSV. A note (*) is added to ACTIONs ‘b’ and ‘c’ to indicate that part of the ACTION is only applicable when the plant is in MODE 1.

Surveillance Requirement 4.7.1.1 is revised to include “The provisions of Specification 4.0.4 are not applicable for entry into Mode 3.” Table 3.7-1 is revised by indicating Operable MSSV versus the maximum allowable power (percent of Rated Thermal Power).

2.2.10 TS 3/4.7.7 Control Room Emergency Ventilation System

Modes 5 and 6 are being deleted from the APPLICABILITY and ACTION section. The revised APPLICABILITY section will read:

- MODES 1, 2, 3, and 4.
- During fuel movement within containment or the spent fuel pool.

The applicability for ACTIONs ‘d’ and ‘e’ will be ‘During Fuel movement within containment or the spent fuel pool.

2.2.11 TS 3/4.7.14 Area Temperature Monitoring

In Table 3.7-6, Area Temperature Monitoring is being revised to eliminate item 11 Turbine Building.

2.2.12 TS 3/4.9.13 Spent Fuel Pool – Reactivity

ACTION ‘b’ is being revised to reflect the addition of Figure 3.9-5.

Surveillance requirement 4.9.13.1.2 is being revised to reflect the addition of decay time to the parameters in Figure 3.9-3 and the title of Figure 3.9-3 has been changed accordingly.

Surveillance requirement 4.9.13.1.3 is being revised to reflect that different configuration limits are specified for the fuel assemblies used exclusively at the pre-uprate power level of 3411 MWt and those assemblies that have been used at the uprate power of 3650 MWt.

Figure 3.9-3 Minimum Fuel Assembly Burnup Versus Nominal Initial Enrichment for Region 2 Storage configuration has been revised to include curves for 0 years, 5 years and 10 years decay time.

The title of Figure 3.9-4 has been changed to the following “Minimum Fuel Assembly Burnup and Decay Time Versus Nominal Initial Enrichment for Region 3 Storage Configuration for Assemblies from Pre-uprate (3411 MWt) Cores.”

A new Figure 3.9-5 has been added to specify the requirements for minimum fuel assembly burnup and decay time versus nominal initial enrichment for Region 3 storage configuration for assemblies from post-uprate (3650 MWt) cores.

2.2.13 TS 5.6 Fuel Storage Criticality

Design Feature 5.6.1.1.b is being revised to reflect the addition of curves of different decay times being added to Figure 3.9-3.

Design Feature 5.6.1.1.c is being revised to reflect the addition of Figure 3.9-5 to reflect the requirements for Region 3 for assemblies used at the post-uprate power level of 3650 MWt.

2.2.14 TS 6.8.4.f Administrative Controls – Containment Leakage Rate Testing Program

The peak calculated containment internal pressure for the design basis loss of coolant accident, $P_{a,}$ is changed from 38.57 psig to 41.4 psig in TS 6.8.4.f.

2.2.15 TS 6.9.1.6 Administrative Controls – Core Operating Limits Report

Section 6.9.1.6.b items 5 and 6 have been revised to reflect the use of the NRC approved Best Estimate ASTRUM Large Break LOCA methodology.

3.0 Licensing Basis Changes

3.1 Safety Grade Cold Shutdown (SGCS)

Standard Review Plan (SRP) 5.4.7, requires that plant safety systems have the capability to bring the reactor to conditions permitting the operation of the residual heat removal (RHR) system within a reasonable period of time, defined as 36 hours, assuming a single failure of an active component with only either onsite or offsite power available. In accordance with the functional requirements of Branch Technical Position (BTP) RSB 5-1, safety grade cold shutdown (SGCS) is defined as the capability of the plant systems to bring the plant from normal operating conditions to cold shutdown, with or without offsite power, with most limiting single failure, using only safety-related equipment and limited action outside of the control room, and within a reasonable period of time following shutdown.

As discussed in MPS3 FSAR Section 5.4.7.2.3.5, the MPS3 SGCS event is postulated to occur as a result of a Safe Shutdown Earthquake (SSE), coincident with a loss of offsite power, and a safety-related electrical distribution system train failure. The train failure disables multiple safe shutdown components, including one RHR train. Thus, SGCS is a natural circulation RCS cooldown event.

As defined in FSAR Section 5.4.7.2.3.5, the MPS3 SGCS design enables the RCS to be taken from HOT STANDBY to conditions that will permit initiation of RHR operation within 36 hours, and then to cold shutdown within an additional 30 hours. Therefore, under the licensing basis for MPS3 the reasonable time period to cold shutdown currently is 66-hours after reactor shutdown. To provide additional margin at SPU conditions, this licensing basis change will establish 72-hours after reactor shutdown as a reasonable time period to cold shutdown for BTP RSB 5-1 design purposes. The 36 hour period to initiate RHR operation is unchanged.

3.2 BTP CMEB 9.5.1 Sections 5.c.3 and 5.c.5-Fire shutdown strategy for long-term steam generator inventory make-up

10 CFR 50.48(a)(1) requires that each operating nuclear plant must have a fire protection plan that satisfies GDC 3. Millstone Unit 3 was licensed after January 1, 1979. Consequently NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Reactors, LWR Edition" was the basis document for the initial licensing basis review. Included in NUREG-0800 is Branch Technical Position (BTP) CMEB 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants." BTP CMEB 9.5-1 presented guidelines acceptable to the NRC Staff for implementing GDC 3 in the development of a fire protection program. Alternative approaches could be requested with suitable bases and justification.

BTP CMEB 9.5.1, Sections 5.c.3 and 5.c.5 define regulatory positions for alternative and dedicated shutdown capability. These regulatory positions state a deterministic fire shutdown analysis requirement that accommodates post fire conditions where offsite power is unavailable for 72 hours. The current fire shutdown strategy is based upon a combined Demineralized Water Storage Tank (DWST) and Condensate Storage Tank (CST) usable inventory that allows for 38-hours of hot standby operation, followed by a 5-hours cooldown to RHR entry conditions. Service water (i.e., seawater from Long Island Sound) is credited for additional long-term SG make-up, as necessary, to support a cooldown to cold shutdown conditions.

Westinghouse Technical Bulletin NSID-TB-89-02 has advised against using seawater as a long-term steam generator (SG) make-up source because a new Westinghouse evaluation had changed the safety perspective concerning SG tube integrity. Specifically, this fission product release barrier could experience through wall failures in 24-hours after seawater introduction due to adverse material interactions.

SPU increases the long-term inventory SG make-up requirements. To avoid increasing SG seawater introduction and exacerbating the SG tube integrity issue, DNC is proposing to modify the current fire shutdown strategy that relies upon service water (seawater) introduction into the SGs. Instead, DNC is proposing use of domestic water, demineralized water or fire water to make-up the DWST and CST. No other modifications are being proposed that would deviate from BTP CMEB 9.5.1, Section 5.c.3 and 5.c.5, “Fire shutdown strategy for long-term steam generator inventory make-up.”

3.3 DWST Licensing Basis Change

The auxiliary feedwater (AFW) system ensures a makeup water supply to the steam generator secondary side to support decay and sensible heat removal for the reactor coolant system. The AFW system is designed to mitigate many accidents including the loss of normal feedwater, feedwater line break, steam generator tube rupture, steam line break, and small break LOCA. The AFW system also supports the heat removal function for other events of regulatory significance such as station blackout, anticipated transient without scram (ATWS) (ATWS), safety grade cold shutdown (SGCS), fire shutdown, and high energy line break (HELB) mitigation. The AFW system includes the demineralized water storage tank (DWST), which is the primary safety-related suction source for the AFW pumps.

MPS3 FSAR Section 10.4.9.1 and Technical Specifications 3/4.7.1.3 require a DWST inventory that is sufficient to maintain the reactor coolant system at HOT STANDBY condition for 10-hours with steam discharge to the atmosphere, concurrent with a total loss-of-offsite power, and with an additional 6-hour cooldown period to reduce reactor coolant temperature to 350° F. This requirement provides for a DWST inventory equivalent to greater than 16-hours of decay heat removal under natural circulation conditions.

The primary impact of the SPU on the AFW system is increased core thermal power and resulting higher decay heat removal requirements during design basis events/accidents, normal cooldown, safety grade cold shutdown, and a station blackout event. A change to the current DWST licensing basis is proposed to address the higher decay heat load. The proposed licensing basis will ensure that sufficient inventory to maintain the reactor coolant system at HOT STANDBY condition for 7-hours with steam discharged to the atmosphere, concurrent with a total loss-of-offsite power, and with an additional 6-hour cooldown period to reduce reactor coolant temperature to 350° F. This requirement provides for a DWST inventory equivalent to greater than 13-hours of decay heat removal under natural circulation conditions.

DNC proposes to process the proposed licensing basis change under 10CFR50.90 and revise the current T/S 3.7.1.3 Bases accordingly to change 10 hours to 7 hours. With this change DNC is indirectly altering the T/S 3.7.1.3 limiting condition of operation.

3.4 Summary

In summary, DNC has reviewed the Operating License, Technical Specifications and FSAR and has determined that no revisions to those documents other than those noted above are required to properly control plant operations and configuration under SPU conditions. Mark-up of the proposed Operating License changes and Technical Specifications changes are provided in Attachment 3. A copy of the proposed mark-up of the Technical Specifications Bases is provided in Attachment 4 and is provided for informational only. Changes to the TS Bases will be made in accordance with the TS Bases Control Program.

4.0 Background

The requested license amendment would authorize DNC to operate MPS3 at 3650 MWt, a 7% increase in power level compared to that authorized by the initial full-term operating license and is therefore defined as a Stretch Power Uprate.

DNC has evaluated the impact of the 7% power uprate for the applicable systems, structures, components, and safety analyses at MPS3. The results of this evaluation are described in Attachment 5 of this submittal, SPU Licensing Report. The SPU Licensing Report provides the details that support the requested Operating License, Technical Specifications, and Licensing Basis changes and together with the other attachments to the amendment request, provides a comprehensive evaluation of the effects of the SPU.

DNC plans to implement the MPS3 SPU in one increment. Completion of plant modifications necessary to implement the SPU is planned to occur prior to the end of the refueling outage in fall of 2008. With the approval of this license amendment request, the plant will be operated at 3650 MWt in Cycle 13.

5.0 Technical Analysis

The acceptability of each of proposed Operating License, Technical Specifications, and Licensing Basis change is addressed below.

5.1 Reactor Core Power Level

Facility Operating License NPF-49, Paragraph 2C.(1), 'Maximum Power Level' is changed to authorize operation at reactor core power levels not in excess of 3650 megawatts thermal.

Technical Specification 1.0, Paragraph 1.27, "RATED THERMAL POWER", is changed from 3411 MWt to 3650 MWt.

As described in Attachment 5, an extensive review of all systems, licensing basis and design basis requirements and all accident analyses has been performed to demonstrate that all requirements will be met at a maximum authorized reactor core power level of 3650 MWt. This review has been conducted in accordance with the guidelines given in RS-001. While it is concluded that the proposed power level change is classified as a Stretch Power Uprate, the guidelines for an Extended Power Uprate have also been used in the LR with a small number of exceptions.

The accident analyses impacted by the power level increase have been re-performed using NRC approved methodologies. In some cases the NRC approved methodologies have been changed from that used for the current safety analyses. When the methodology has been changed, evaluations have been performed to assure that all limitations and restrictions of the new NRC approved methodologies have been met. The analyses and evaluations documented in the LR have identified a small number of modifications necessary to assure that all design basis requirements are met. These modifications, with the evaluations and analyses performed as documented in the LR, provide assurance that all design basis requirements, including the radiological dose limits, are met.

5.2 Safety Limits

The departure from nucleate boiling ratio (DNBR) limit in Technical Specification 2.1.1.1 is changed from 1.17 to 1.14 and DNB correlations WRB-1 and WRB-2 are replaced with WRB-2M. The DNBR analyses described in SPU LR (Attachment 5) utilize the WRB-2M correlation. The WBR-2M DNBR correlation was developed from test bundles simulating the Robust Fuel Assembly (RFA) fuel design. This is applicable to the fuel cycle that MPS3 will implement the stretch power uprate since all of the assemblies in the core will be of the

RFA/RFA-2 design. The WRB-2M correlation is more accurate for the RFA design and will provide additional DNBR margin to offset the impact on DNBR of the increased power level. As discussed in LR Section 2.8.5 (Attachment 5), the NRC has approved the use of the WRB-2M DNBR correlation as implemented in the VIPRE computer code. All limitations and restrictions on the use of WRB-2M as implemented in the VIPRE code have been met in the DNBR analyses. Where the plant conditions were outside the applicable range of the WRB-2M correlation, the WRB-2 or W-3 DNB correlation was used with the appropriate limits. These two correlations are already approved for use for MPS3 DNBR analyses. Thus, it is concluded that WRB-2M can be applied to MPS3.

5.3 RCS Total Flow Rate

Technical Specification Table 2.2-1 Reactor Trip System Instrumentation Trip Setpoints, Functional Unit 12, Reactor Coolant Flow-Low is revised from ‘loop design flow’ to ‘nominal loop flow’ and corresponding footnote is deleted. No change to the nominal trip setpoint or allowable value is proposed.

Technical Specification 3.2.3.1.a is revised as follows: the RCS total flow rate is revised from $\geq$ 371,920 gpm to $\geq$ 363,200 gpm.

In Amendment 236 the NRC approved a DNC Technical Specifications change request to relocate a number of parameters, including the RCS total flow requirement to the Core Operating Limits Report (COLR). The COLR is maintained in the licensee controlled Technical Requirements Manual and changes are governed by 10 CFR 50.59. This Technical Specification change was made in accordance with TSTF-339 where the RCS total flow rate minimum value is retained in Technical Specifications in order to assure that an RCS total flow rate is not lower than that approved by the NRC. The minimum limit for RCS total flow (e.g., maximum tube plugging) is retained in the MPS3 Technical Specification 3.2.3.1.a.

As described in LR Section 1.1 (Attachment 5), as part of the uprate analysis a new set of nominal RCS operating conditions at the uprate power level has been established. All uprate evaluations and analyses have been performed using these RCS operating conditions. The RCS design flow corresponding to 10% SG tube plugging used in the uprate analyses is 363,200 gpm. Thus, the RCS total flow rate in Technical Specification 3.2.3.3.1.a is being revised to reflect this design value. It should be noted that the current Technical Specification value does not correspond to the minimum limit for RCS flow corresponding to 10% SG tube plugging. The current value is the same as the RCS total flow value currently in the COLR that is the minimum measured flow used in combination with the other relocated parameters that may change from cycle-to-cycle. The intent of TSTF 339 was to relocate the minimum measured flow to the COLR and to include the design flow in Technical Specifications. When Technical Specification change request for Amendment 236 was submitted and approved, the minimum RCS flow (Design Flow) consistent with the 10% SG tube-plugging limit was not specified. For the SPU, all of the evaluations and limiting design basis analyses have been performed assuming a design flow of 363,200 gpm corresponding to 10% SG tube plugging.

The footnote for functional unit 12 in TS Table 2.2-1 is meant to indicate that the RCS low flow setpoint is set greater than or equal to 90% of measured flow, which is much higher than design flow. The current specification and footnote are confusing. The TS requirement can be more accurately described as nominal loop flow and therefore, the footnote can be deleted. This does not represent a change in the TS requirement.

Surveillance Requirements 4.2.3.1.4 and 4.2.3.1.5 currently require that the measurement instrumentation be calibrated within seven days prior to the performance of the RCS total flow rate measurements. This seven day requirement is deleted from the Technical Specifications. Current Surveillance requirement 4.2.3.1.3 is being deleted because its requirement is included in the proposed Surveillance Requirement 4.2.3.1.3.b. Surveillance Requirement 4.2.3.1.5 is being deleted. The measurement error of the RCS total flow rate is based upon performing a precision heat balance (proposed surveillance requirement 4.2.3.1.3.a) and using the results to calibrate the RCS flow rate indicators. To perform the precision heat balance, the instrumentation used for determination of steam pressure, feedwater pressure, feedwater temperature, and feedwater venturi ΔP in the calorimetric calculation are calibrated once per 18 months. The RCS total flow rate measurement requirements of Surveillance Requirement 4.2.3.1.5 is included in Surveillance Requirement 4.2.3.1.3. Additionally 4.2.3.1.6 is proposed for deletion.

As part of the uprate, the uncertainty analysis has been updated as required. The RCS total flow uncertainty calculation incorporates a drift allowance that covers the 18 month interval plus a 25% allowance. However to comply with the uncertainty analysis assumptions it is necessary to require the RCS flow rate to be determined at no less than 90% of the RTP. This is also appropriate since the heat balance requires the plant to be at a minimum of 90% of the RTP to obtain the stated RCS flow accuracies. This surveillance shall be performed within 24 hours after reaching 90% of the RTP. As a result, it is unnecessary to require the RCS flow rate to be determined prior to operation above 75% of RTP after each fuel loading. In addition, it is unnecessary to require the RCS flow measurement instrumentation to be calibrated within 7 days of the calorimetric flow measurement. Thus, it is proposed that this requirement for calibration be deleted from Surveillance Requirements 4.2.3.1.4 and 4.2.3.1.5.

The RCS total flow rate contains a measurement error based on performing a precision heat balance and using the result to calibrate the RCS total flow rate indicators. Potential fouling of the feedwater venturi, which might not be detected, could bias the result from the precision heat balance in a non-conservative manner. Therefore, a penalty for undetected fouling of feedwater venturi raises the nominal flow measurement allowance for no fouling. Any fouling that might bias the RCS total flow rate measurement greater than the penalty for undetected fouling of the feedwater venturi can be detected by monitoring and trending various plant performance parameters. If detected, either the effects of the fouling shall be quantified and compensated for in the RCS total flow rate measurement or the venturi shall be cleaned to eliminate the fouling. Therefore, it is acceptable to delete Surveillance Requirement 4.2.3.1.6.

5.4 P-8 Reactor Protection System Interlock

In Technical Specification Table 2.2-1 the Reactor Trip System Interlocks- Power Range Neutron Flux, P-8 nominal trip setpoint is increased from 37.5% to 50.0% of RTP and Allowable Value is increased from ≤38.1% to ≤50.6% of RTP.

As discussed in the Technical Specifications bases for Reactor Trip System Interlocks, on increasing power, P-8 automatically enables reactor trips on low flow in one or more reactor coolant loops. On decreasing power, the P-8 automatically blocks the reactor trip from low flow in only one reactor coolant loop.

LR Section 2.8.5 (Attachment 5) documents the analysis performed to demonstrate the adequacy of a P-8 nominal trip setpoint of 50% at uprated conditions. A single reactor coolant pump is assumed to be tripped at an initial power of 60% of the uprated power level. The results confirm that there is a large margin to DNB and to the RCS pressure limit. This analysis confirms that at a nominal power of 50% at uprated conditions, all safety analysis limits will be met following the coastdown of a single reactor coolant pump without crediting the reactor trip on low RCS flow. Thus, the proposed P-8 setpoint is acceptable.

The current setpoint has not been changed for many cycles and was originally determined to address both N loop operation and N-1 loop operation. For this trip interlock, the limiting condition was N-1 loop operation. The setpoint was not changed when the Technical Specifications were changed to eliminate the possibility of N-1 loop operation. As a result the uprate analysis shows that all requirements can be met with a higher nominal P-8 setpoint of 50%.

5.5 Over Temperature Delta Temperature (OTΔT) and Overpower Delta Temperature (OPΔT) Setpoints

In Technical Specification Table 2.2-1 Reactor Trip System Instrumentation Trip Setpoints, the second term, the K5 term, in the Note 3 equation is being deleted. The rate lag compensator card for T_{avg} input to the OPΔT is being eliminated from the control system.

In the past, MPS3 has experienced hot leg temperature spiking associated with the phenomena known as upper plenum anomaly. These spikes may lead to pre-trip alarms for the OTΔT and OPΔT setpoints. In the limiting condition, inadvertent trips may be experienced. To address the potential for these phenomena to be more frequent at uprated conditions, a DNBR study was performed to determine the optimum solution that would provide margin from spurious alarms and trips, while still maintaining the required margin for DNBR. As a result of the study, it was decided to implement a design change that will add an electronic filter to the hot leg temperature signal from the hot leg RTDs. The filter will reduce the number of spurious alarm trips due to potential hot leg temperature spiking. To offset the DNBR impact of the filter, the OTΔT and OPΔT setpoints were optimized. As a result of the optimization study, it was determined that the K5 term in the OPΔT equation is no longer needed. As a result, the electronic card implementing the K5 term will be removed and replaced with the electronic card to implement the hot leg temperature filter.

As documented in LR Section 2.8.5 (Attachment 5), the DNBR analysis shows that the DNBR limits will be met for all FSAR Chapter 15 events as required, assuming the implementation of the hot leg temperature filter and the optimized OTΔT and OPΔT setpoints.

With the implementation of the hot leg temperature filter, the current margin to spurious alarms and trips due to temperature spikes from the upper plenum anomaly will be maintained. Thus, any increase in the likelihood of a spurious trip due to the upper plenum anomaly is expected to be minimal.

5.6 RCS Low Pressure Permissive for Opening the ECCS Charging Injection Valves Following a Safety Injection

For Technical Specification 3/4.3.2, a new functional unit 11, ‘ Cold Leg Injection Permissive, P-19 ’, is added to Table 3.3-3, Engineered Safety Features Actuation System Instrumentation, Table 3.3-4, Engineered Safety Features Actuation System Instrumentation Trip Setpoints and Table 4.3-2, Engineered Features Actuation System Instrumentation Surveillance Requirements. This permissive will be derived utilizing the existing low pressurizer pressure reactor trip 2/4 bistable trip logic but will not be blocked by the P-7 interlock (Low Power

Reactor Trip Block) and will be required to be operable during Modes 1, 2, and 3. The permissive will have the same setpoint (1900 psia) and same allowable value ($\geq$ 1897.6 psia) as that of the low pressurizer pressure reactor trip. Should the P-19 permissive interlock be inoperable ACTION 20 applies. Surveillance Requirements for this functional unit are added to Table 3.3-4.

The current analysis for an inadvertent safety injection actuation at power documented in FSAR Section 15.5.1 shows that there is 10.7 minutes for operator action to preclude water relief from the pressurizer safety valves for which the pressurizer safety valves are not designed. Because of the higher RCS average temperature associated with the increased power level, a higher pressurizer level is needed to assure the pressurizer heaters will not uncover during a routine reactor trip. The higher pressurizer level will reduce the margin for operator action.

On December 14, 2005, the NRC issued Regulatory Issue Summary (RIS) 2005-29, “Anticipated Transients That Could Develop Into More Serious Events”. RIS 2005-29 was issued to communicate deficiencies in power uprate license amendment requests with respect to the analysis of the inadvertent ECCS actuation event. The deficiencies involve credit for timely operator action and the qualification requirements for the pressurizer PORVs and safety valves. The NRC issued this RIS to allow licensees an opportunity to develop resolutions to these deficiencies before they arise during the licensing process for an uprate.

MPS3 has safety-grade pressure-operated relief valves and piping that supports water relief from the PORVs during an event. The current analysis for an inadvertent ECCS actuation at power documented in FSAR Section 15.5.1 shows that operator action within ten minutes is required to assure at least one PORV is available to prevent water relief from the pressurizer safety valves for which they are not qualified. This operator action time frame will be reduced at the SPU conditions. To prevent a pressurizer water-solid condition and/or to allow ample time for the operators to restore a proper alignment prior to reaching a pressurizer water solid condition, it was determined to implement the proposed modification.

The proposed modification is the addition of a new SIAS interlock that will provide a Cold Leg Injection Permissive to permit automatic opening of the charging ECCS injection valves following a SIAS. The Cold Leg Injection Permissive is activated when two of the four low pressurizer pressure channels indicate less than 1900 psia. The modification will be designed to meet all of the appropriate codes and standards such as IEEE 279 and the appropriate separation criteria. With this permissive in place, a SIAS actuation from any other signal other than low RCS pressure will prevent water injection through the ECCS charging pathway. With RCS pressure above the Cold Leg Injection Permissive setpoint, the RCS pressure will be too high for High Pressure or Low

Pressure Safety injection. The only water injection to the RCS would come from Reactor Coolant Pump seal injection from charging. This will result in a significant increase in the available time for operator response to mitigate the event. As documented in LR Section 2.8.5.5 (Attachment 5), over 70 minutes are available for operator action to mitigate this event with this new interlock in place.

Since the low RCS pressure RPS setpoint is higher than the low RCS pressure SIAS setpoint, there will be no change in ECCS performance for those events where RCS injection from ECCS is required. ECCS injection is not credited for mitigating steam line or feedwater line breaks. ECCS actuation is only credited for Steam Generator Tube Rupture and LOCAs. Since these events result in RCS pressure dropping below the RPS low pressurizer pressure setpoint, it is concluded that there is no impact on assumptions for ECCS performance.

The risk significance for this modification has also been assessed (See LR Section 2.13 of Attachment 5). The implementation of this modification would result in a small reduction in Core Damage Frequency (CDF), on the order of 1E-07 to 1E-08 per year. The impact on SI reliability due to the design change is acceptably small.

Since this new SIAS interlock is credited in the accident analysis it is being added to Technical Specification Table 3.3-3. The action statements and surveillance are proposed to be the same as the RPS low pressurizer pressure trip since it is the source of the signal implementing the interlock.

5.7 Control Building Isolation

For Technical Specification 3.3-2, the asterisk note in TABLE NOTATIONS for Table 3.3-3 and Table 4.3-2, the Mode applicability is being changed to eliminate Modes 5 and 6. The new asterisk note will read:

- MODES 1, 2, 3, and 4.
- During fuel movement within containment or the spent fuel pool.

Similarly, for Technical Specification 3/4.7.7 Control Room Emergency Ventilation system, Modes 5 and 6 are being deleted from the APPLICABILITY section. The revised APPLICABILITY section will read:

- MODES 1, 2, 3, and 4.
- During fuel movement within containment or the spent fuel pool.

As discussed in LR Section 2.9.2 (Attachment 5), at the uprate conditions, a revision to the source term used in the analysis for the radiological consequences for the fuel handling accident is necessary.

Following the SPU, the limiting discharge assembly will have rods with burnup exceeding 54 GWD/MTU and exceeding 6.3 kw/ft peak rod average power. At SPU conditions, it has been determined that 67% will bound the fraction of the limiting discharge assembly fuel rods that are expected to exceed 54 GWD/MTU and 6.3 kw/ft peak rod average power. For these rods, the gap fractions listed in Regulatory Guide 1.25 (as modified by the direction of NUREG/CR-5009) are used with the design peaking factor of 1.7. The remaining 33% of the fuel rods are assumed to comply with the criteria of Regulatory Guide 1.183, Table 3, footnote 11, and utilize the gap fractions from Regulatory Guide 1.183, Table 3.

However, because of this increase in the release fractions, the control room emergency ventilation system is assumed to be in operation within 30 minutes of the fuel handling accident. This action is required to meet the established dose limits specified in 10 CFR 50.67. A modification (LR Section 2.4.1) will be implemented to address this assumption that will not require new operator action.

As discussed in LR Section 2.9.2 (Attachment 5), a new analysis of a fuel-handling event involving the drop of a non-spent fuel assembly component into the spent fuel pool was performed to demonstrate that operation of the control room emergency ventilation system is not necessary for these types of activities in the spent fuel pool. As a result, the requirements to maintain the OPERABILITY of the Control Room Emergency Air Filtration Systems in Modes 5 and 6 are no longer necessary. Thus, it is proposed to remove the applicability of Modes 5 and 6 for the Control Room Emergency Air Filtration Systems.

5.8 Pressurizer Level

TS Figure 3.4-5 is being replaced by a new figure to reflect a new pressurizer level control program. This revised pressurizer level control program supports the revised transient analysis and accommodates RCS shrink and swell at SPU conditions.

As discussed in LR Section 1.1 (Attachment 5), the evaluations and analyses support operation for a RCS average temperature between 571.5 degrees F and 589.5 degrees F. The current RCS average temperature is 587.1 degrees F. However, the no-load temperature of 557 degrees F is not being changed. For uprated operation, at 589.5 degrees F there is 32.5 degrees F difference between 100% power and no load, compared to the current difference of 30.1 degrees F. Thus, following a reactor trip at full uprated power, there will be increased RCS shrinkage. This increased shrinkage will cause a temporary decrease in pressurizer level that could uncover the pressurizer heaters and cause letdown isolation. To continue to provide margin for pressurizer heater uncovery and letdown isolation at uprated conditions, the pressurizer level program has been modified to raise the pressurizer level to 64% when RCS average temperature is between 587 and 589.5 degrees F.

As discussed in LR Section 2.8.5 (Attachment 5), the new pressurizer level program has been taken into account in all of the accident analyses. For those events where pressurizer level is a factor in the analysis, a 7.6% uncertainty has been taken into account with the new pressurizer level program. The results for all accident analyses are acceptable with the revised pressurizer level program.

Thus, the revised pressurizer level program provides assurance that the pressurizer heaters will remain covered with water and letdown will remain in service as expected for routine reactor trips and that all of the accident analysis results are acceptable.

5.9 Turbine Cycle

The changes are being made to the allowable power level with inoperable MSSVs to reflect the SPU Analyses. The specific Technical changes are described in Section 2.2.9.

In 1994, Westinghouse issued Nuclear Safety Advisory Letter NSAL-94-001 identifying a deficiency in the basis for Technical Specification 3.7.1. The Technical Specifications allow the plant to operate with a reduced number of operable MSSVs at a reduced power level. Without the adequate power level adjustment, this condition may result in secondary side overpressurization in the event of a loss of load or turbine trip. NSAL 94-001 provides an algorithm for calculating the thermal power limit and power range high neutron flux setpoint as a function of number of inoperable safety valves. In Amendment 102 (dated July 31, 1995), the MPS3 Technical Specifications 3.7.1.1 was revised to incorporate a different setpoint using the NSAL 94-001 methodology for determining the maximum allowable power range neutron flux setpoint. These changes allowed MPS3 to operate with a reduced number of MSSVs at a reduced power level, as determined by the high flux setpoint. As documented in LR Section 2.8.4.2, this algorithm was applied to the uprate conditions and has resulted in a reduction in the setpoints currently given in Technical Specification Table 3.7-1.

In addition, the current MPS3 Technical Specification Action Statements are inconsistent with NUREG-1431 “Standard Technical Specifications – Westinghouse Plant.” Since a revision to this Technical Specification is required, it is proposed that the Action Statements be reworded to be consistent with this industry standard. Since the basis for the NUREG-1431 TS 3.7.1 is the algorithm described in NSAL 94-0001, and this algorithm has been used to determine the proposed power levels and trip setpoints with inoperable MSSVs, the NUREG-1431 wording is directly applicable to MPS3.

The analysis described in LR Section 2.8.4.2 (Attachment 5), provides assurance that the appropriate power reductions at uprated conditions will take place with inoperable MSSVs to assure that the pressure in both the Secondary and Primary system will remain below the required ASME limits in the event that the limiting overpressurization event occurs during the time period that the MSSV(s) are inoperable.

5.10 Turbine Building Temperature Monitoring

TS Table 3.7-6, Area Temperature Monitoring requires that the temperature in the Turbine Building be maintained at or below 115 degrees F in order to assure the environmental profile for qualified equipment in the Turbine Building is maintained.

There are two sets of equipment in the Turbine Building that have been environmentally qualified and are maintained on the Master Equipment List for environmentally qualified equipment. These are:

- Pressure transmitters PT 505 and 506 that measure first stage pressure
- Valve position switches MSS ZS59, 60, 61 and 62 for the main steam turbine stop valves

Pressure transmitters PT 505 and 506 are currently on the Master Equipment List because they provide input into the rod control system. A failure of these transmitters as a result of a steam line break in the Turbine Building could result in control rod withdrawal. However, a modification is being made to eliminate the capability for automatic rod withdrawal by the rod control system as referred to in LR Section 2.4.1 (Attachment 5). This modification will ensure that a steam line break in the turbine building will not result in a consequential power increase due to rod withdrawal. As such, a change will be processed to remove PT 505 and 506 from the Master Equipment List.

Valve position switches MSS ZX59, 60, 61 and 62 provide the turbine trip signal that will generate the reactor trip. This is a backup non-safety grade trip function not credited in any accident analyses, including a steam line break. As such, a change will be processed to remove MSS ZS59, 60, 61 and 62 from the Master Equipment List.

With removal of pressure transmitters PT 505 and 506 and position switches MSS ZS59, 60, 61 and 62, there will be no equipment located in the turbine building that is on the Master Equipment List. Thus, it is no longer necessary to maintain environmental profiles for the turbine building, and the temperature monitoring in the turbine building can be removed.

5.11 Spent Fuel Pool Requirements

The following Technical Specification changes are being made:

For Technical Specification 3/4.9.13 Spent Fuel Pool – Reactivity:

a. ACTION ‘b’ is being revised to reflect the addition of Figure 3.9-5.

b. Surveillance requirement 4.9.13.1.2 is being revised to reflect the addition of decay time to the parameters in Figure 3.9-3.

c. Surveillance requirement 4.9.13.1.3 is being revised to reflect that different configuration limits are specified for the fuel assemblies used exclusively at the pre-uprate power level of 3411 MWt and those assemblies used at the uprate power of 3650 MWt.

d. Figure 3.9-3 Minimum Fuel Assembly Burnup Versus Nominal Initial Enrichment for Region 2 Storage configuration has been revised to include curves for 0 years, 5 years and 10 years decay time, and the title of Figure 3.9-3 has been changed accordingly.

e. The title of Figure 3.9-4 has been changed to the following “Minimum Fuel Assembly Burnup and Decay Time Versus Nominal Initial Enrichment for Region 3 Storage Configuration for Assemblies from Pre-Uprate (3411 MWt) Cores.”

f. A new Figure 3.9-5 has been added to specify the requirements for minimum fuel assembly burnup and decay time versus nominal initial enrichment for Region 3 storage configuration for assemblies from Post-uprate (3650 MWt) Cores.

For Technical Specification Design Features 5.6 Fuel Storage Criticality:

a. Design Feature 5.6.1.1.b is being revised to reflect the addition of curves of different decay times being added to Figure 3.9-3.

b. Design Feature 5.6.1.1.c is being revised to reflect the addition of Figure 3.9-5 to reflect the requirements for Region 3 for assemblies used at the post-uprate power level of 3650 MWt.

Because of operation at uprate power, the spent fuel can be potentially more reactive. As discussed in LR Section 2.8.6.2 (Attachment 5), a revised spent fuel criticality analysis at uprated conditions has been performed. This new spent fuel pool criticality analysis has been used to determine the impact of storing fuel used at the uprate power of 3650 MWt in the spent fuel pool.

Because of the potential increase in the number of assemblies to be loaded on a cycle-by-cycle basis, some of the discharge assemblies may not meet the current requirements for Region 2, potentially requiring storage in Region 1, where space is limited. In order to minimize the impact on Region 1, decay time dependent curves have been calculated for Region 2. This will allow discharge assemblies that are temporarily stored in Region 1 to be moved into Region 2 as the increase in decay time allows.

For Region 3, the revised analysis shows that more restrictive limits are needed for fuel used at the uprate power. Thus, a new figure is provided to specify the configuration limits for the spent fuel used at the uprate power level for storage Region 3.

The revised spent fuel pool criticality analysis, together with the proposed changes in Technical Specification requirements for Spent Fuel Pool Regions 2 and 3, provide assurance that all subcriticality requirements will be met for storage of fuel used at the uprate power level of 3650 MWt.

5.12 Peak Calculated Containment Internal Pressure

The peak calculated containment internal pressure for the design basis loss of coolant accident, P_a, is changed from 38.57 psig to 41.4 psig in TS 6.8.4.f. As discussed in LR Section 2.6.1 (Attachment 5), Primary Containment Functional Design, the LOCA containment transient analysis (pressure and temperature) was performed using the GOTHIC computer code and the NRC-approved analysis methodology described in topical report DOM-NAF-3-0.0-P-A. A spectrum of mass and energy release rates are considered that represent a limiting set of break sizes and locations in order to demonstrate that the containment design pressure and temperature limits will not be exceeded following a LBLOCA inside containment. The spectrum includes the largest cold and hot leg breaks, and range of pump suction breaks from the double-ended break with discharge coefficients of 1.0 and 0.6 down to a 3.0 ft^2 split break. These mass and energy release rates form the basis of GOTHIC computations to evaluate the containment response following the postulated LOCA scenarios and to ensure that containment design margin is maintained. The maximum peak containment pressure occurs after a Double Ended Hot Leg break. As documented in Table 2.6.1.2.2-1 of LR Section 2.6.1 (Attachment 5), the calculated containment pressure (41.4 psig) is below the containment design pressure of 45 psig. The results of the containment temperature analysis are tabulated in Table 2.6.1.2.2-4 of LR Section 2.6.1. The results demonstrate the calculated containment temperature profile is well bounded by the analyzed values of environmentally qualified equipment inside the containment. Therefore it is concluded the proposed technical specification change in TS 6.8.4.f related to the calculated containment internal pressure for the design basis LOCA is acceptable.

5.13 Large Break LOCA Methodology

Technical Specification 6.9.1.6.b items 5 and 6 have been revised to reflect the use of the NRC approved best estimate ASTRUM Large Break LOCA methodology. As discussed in LR Section 2.8.5, the uprate Large Break LOCA analysis has been performed using the Westinghouse Best Estimate ASTRUM Large Break LOCA analysis methodology. The Best Estimate ASTRUM Large Break LOCA analysis methodology provides margin to offset the impact of the uprate conditions on the Large Break LOCA analysis. This methodology has been approved by the NRC and has been reviewed and approved for use for a number of other plants. The MPS3 ASTRUM analysis performed at uprate condition conforms to all restrictions and limitations of the methodology and NRC approval of the methodology. As shown in LR Section 2.8.5, the results of the Best Estimate ASTRUM Large Break LOCA analysis meet all of the requirements of 10 CFR 50.46.

5.14 Safety Grade Cold Shutdown (SGCS)

As defined in FSAR Section 5.4.7.2.3.5, the MPS3 SGCS design enables the RCS to be taken from HOT STANDBY to conditions that will permit initiation of RHR operation within 36 hours, and then to cold shutdown within an additional 30 hours. Therefore, for MPS3 a reasonable time period to cold shutdown is defined as 66-hours after reactor shutdown. To provide additional margin at SPU conditions, this licensing basis change will re-define 72-hours after reactor shutdown as a reasonable time period to cold shutdown for BTP RSB 5-1 design purposes. The 36 hour period to initiate RHR operation is unchanged.

Based upon engineering judgment, there is negligible impact on nuclear safety if cold shutdown occurs within 72 hours, as opposed to within 66-hours,. Specifically, the requested BTP RSB 5-1 “reasonable time period” change is driven by the SGCS analysis two-train available case results (see LR Section 2.8.4.4, Table 2.8.4.4-6). For MPS3, the SGCS analysis’s two-train available case has longer cooldown times because manual action outside the control room to throttle a postulated failed open air operated RHR heat exchanger flow control valve via a local jacking screw is not credited within the cooldown analysis due to BTP RSB 5-1 design/analysis criteria. If plant operators locally throttle the RHR control valve, as is credited in the SGCS one-train available case, the SGCS two-train available case would have better cooldown times than the single-train available case which has demonstrated a less than 50-hour cold shutdown cooldown time capability (see LR Section 2.8.4.4, Table 2.8.4.4-5). Thus, for MPS3, there is negligible impact on nuclear safety due to this change.

5.15 BTP CMEB 9.5.1, Sections 5.c.3 and 5.c.5 Deviations

Facility Operating License No. NPF-49, Condition 2.H “Fire Protection” states the following:

> “Dominion Nuclear Connecticut, Inc. shall implement and maintain in effect all provisions of the approved fire protection program as described in the final Safety Analysis Report for the facility and as approved in the SER NUREG-1031) issued in July 1984 and supplements Nos. 2, 4, and issued September 1985, November 1985, and January 1986, respectively, subject to the following provision:

The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.”

Title 10 of the Code of Federal Regulations (CFR) Section 50, Appendix A, General Design Criterion, 3 (GDC 3) states in part:

> “Fire detection and fighting systems of appropriate capacity and capability shall be provided and designed to minimize the adverse effects of fires on structures, systems and components important to safety.”

10 CFR 50.48(a)(1) requires that each operating nuclear plant must have a fire protection plan that satisfies GDC 3. Millstone Unit 3 was licensed after January 1, 1979. Consequently NUREG-0800, Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Reactors, LWR Edition” was the basis document for the initial licensing basis review. Included in NUREG-0800 is Branch Technical Position (BTP) CMEB 9.5-1, “Guidelines for Fire Protection for Nuclear Power Plants.” BTP CMEB 9.5-1 presented guidelines acceptable to the NRC Staff for implementing GDC 3 in the development of a fire protection program. Alternative approaches could be requested with suitable bases and justification.

BTP CMEB 9.5.1, Sections 5.c.3 and 5.c.5 define regulatory positions for alternative and dedicated shutdown capability. These regulatory positions state a deterministic fire shutdown analysis requirement that accommodates post fire conditions where offsite power is unavailable for 72 hours.

The current fire shutdown strategy is based upon a combined Demineralized Water Storage Tank (DWST) and Condensate Storage Tank (CST) usable inventory that allows for 38-hours of hot standby operation, followed by a 5-hours cooldown to RHR entry conditions. Service water (i.e., seawater from Long Island Sound) is credited for additional long-term SG make-up, as necessary, to support a cold shutdown conditions.

Westinghouse Technical Bulletin NSID-TB-89-02 has advised against using seawater as a long-term steam generator (SG) make-up source because a new Westinghouse evaluation had changed the safety perspective concerning SG tube integrity. Specifically, this fission product release barrier could experience through wall failures in 24-hours after seawater introduction due to adverse material interactions.

SPU increases the long-term inventory SG make-up requirements. To avoid increasing SG seawater introduction and exacerbating the SG tube integrity issue, DNC is proposing a fire shutdown strategy that does not rely upon seawater introduction into the SGs. Instead, DNC is proposing use of domestic water, demineralized water, or fire water to make-up the DWST and CST. There are no other modifications being proposed that would deviate from BTP CMEB 9.5.1, Section 5.c.3 and 5.c.5, “Fire shutdown strategy for long-term steam generator inventory make-up”.

The AFW system includes a DWST, which is the primary safety related suction source for the AFW pumps. The AFW system has cross-connect design features that allow the AFW pumps to be aligned to the CST or the service water system (seawater).

As documented in the MPS3 current licensing basis, service water is credited for long-term SG make-up, as necessary, to support obtaining a cold shutdown condition. LR Section 2.5.1.4 documents the post fire long-term shutdown strategy that does not credit service water as the means of replenishing auxiliary feedwater for safe shutdown. Instead, the DWST and CST will be replenished with make-up water from sources such as domestic water, demineralized water, and firewater. This strategy improves the reliability of a fission product barrier (i.e., SG tube integrity). Relative to the reliability of the decay heat removal design function during a fire event, there is negligible impact on the risk of radiological releases to the environment due to a fire. In addition, this proposed change continues to comply with 10 CFR 50.48 and GDC 3 requirements.

5.16 DWST Licensing Basis Change

The proposed licensing basis will ensure that sufficient inventory to maintain the reactor coolant system at HOT STANDBY condition for 7 hours (instead of 10 hours currently required) with steam discharged to the atmosphere, concurrent with a total loss-of-offsite power, and with an additional 6-hour cooldown period to reduce reactor coolant temperature to 350° F. T/S 3.7.1.3's limiting condition for operation (i.e., 334,000-gallon measured volume) remains unchanged. No change to inventory spillage, uncertainty or unusable volume allowances is proposed.

LR Section 2.5.4.5, "Auxiliary Feedwater System", Table 2.5.4.5-1 and Table 2.5.4.5-2 provides details on the new DWST design and licensing basis. No change in the SGCS analysis RHR-entry time is required to support this change. Engineering analyses associated with LR Section 2.8.7.2, "Natural Circulation Cooldown" has confirmed that SPU has no adverse impact upon the existing RHR entry time assumption, which is based, in part, upon RCS boration and cooldown to RHR entry condition performance capabilities.

After SPU, at least 13-hours of usable inventory will remain available for decay heat removal before the tank is exhausted (under natural circulation conditions). There is no significant increase in the likelihood that plant operators will fail to refill the DWST (or to realign the AFW pumps to an alternate suction source such as the CST) in time, if additional inventory is required. In the event of a major seismic event (which may decrease the available DWST refill/AFW pump suction realignment options), the SPU safety grade cold shutdown (SGCS) analysis has demonstrated the DWST continues to contain sufficient inventory such that cold shutdown conditions can be obtained with the existing T/S 3.7.1.3 limiting condition for operation (i.e., a measured 334,000-gallon inventory).

The proposed licensing basis change provides adequate inventory for accident analysis primary success paths and provides adequate inventory which operating experience and/or probabilistic risk assessment has shown to assure public health and safety. Licensing Report Section 2.13, "Risk Evaluation" supports this risk assessment conclusion.

LR Section 2.5.4.5 documents the proposed change is acceptable relative to functional requirements derived from station blackout. A separate licensing bases change is associated with inventory requirements derived from the fire shutdown analysis (see LR Section 2.5.1.4).

In summary, the proposed change provides sufficient DWST inventory for accident analysis primary success paths; safety grade cold shutdown (i.e., BTP RSB 5-1 compliance); and station blackout. There is no significant change in the likelihood plant operators would fail to refill the DWST (or realign the AFW pump suction source), if additional inventory is required.

6.0 Regulatory Analysis

6.1 No Significant Hazards Consideration

The proposed license amendment will revise the MPS3 Facility Operating License NPF-49 and the Technical Specifications to increase the licensed core thermal power by approximately 7% from 3411 MWt to 3650 MWt. In addition, the proposed amendment also includes changes to the MPS3 current licensing basis that require prior NRC review and approval in accordance with 10 CFR 50.59. The proposed changes are described in detail in Section 2 of this attachment and are also indicated on the marked up page for the Operating License and the Technical Specifications contained in Attachment 3. The changes to the Operating License, Technical Specifications and licensing basis have been grouped and each group is evaluated pursuant to the requirements of 10 CFR 50.92 and presented below.

6.1.1 Reactor Core Power Level

Facility Operating License NPF-49, Paragraph 2C.(1),'Maximum Power level' is changed to authorize operation at reactor core power levels not in excess of 3650 Megawatts Thermal. Technical Specifications 1.0, Paragraph 1.27, "Rated Thermal Power," is changed from 3411 MWt to 3650 MWt.

6.1.1.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

As documented in the License Report, evaluations have been performed to demonstrate that all plant equipment will operate within their design ranges at the SPU conditions.

LR Section 2.2.6 NSSS Design Transients documents how the NSSS design transients were updated for SPU conditions. These NSSS Design Transients include Normal Condition Transients, Upset Condition Transients, Emergency Condition Transients and Faulted Condition Transients. These transients were used in the evaluation of NSSS component structural capacity and fatigue at the SPU condition to assess the capability of the NSSS to operate as expected for the remainder of plant life. LR Section 2.2 documents the evaluation of the impact of the revised design transients on the NSSS equipment. As a result of this evaluation, it was determined the pressurizer level at full power needs to be increased to assure that the pressurizer heaters will not be uncovered and letdown remain unisolated following a routine reactor trip. This will provide assurance the likelihood of a pressurizer heater failure will not be affected by the SPU. This modification together with the equipment evaluations, provide assurance all NSSS components will operate within their design and the uprate will have no impact on the likelihood of failure of any equipment that can cause an accident.

Similar evaluations have been performed for the Balance of Plant (BOP) equipment. These are described in LR Sections 2.2 through 2.7. These sections document the evaluation of all potentially affected equipment. Modifications are planned for the turbines for the turbine driven feedwater pumps, the turbine building HVAC system, some pipe supports for various systems and some BOP instrumentation and controls. These modifications will assure that all BOP equipment will operate as designed at SPU conditions. Thus, the SPU will have no impact on the failure of any equipment that can consequentially cause an accident.

LR Section 2.4.2 “Plant Operability” documents the SPU impact on the capability of NSSS I&C systems to respond to initiation of operational transients without initiating a reactor trip or ESF actuation signal. The following operational transients were evaluated:

- 5%/minute unit loading and unloading
- 10% step load increase
- 10% step load decrease
- 50% load rejection (50% loss of net load at 200%/minute)

The evaluation addressed Tavg coastdown from 581.5 to 571.5 degrees F as well as the Tavg operating band from 589.5 to 581.5 degrees F. These evaluations also conservatively assumed two of nine condenser dump valves were unavailable.

The SPU analysis has demonstrated the NSSS I&C systems will continue to respond to these operational events without requiring a reactor trip or ESF actuation signal. Thus, it is concluded that SPU has no impact on the likelihood of an operational transient causing an accident.

The evaluation also addressed the impact of SPU on the acceptability of the current setpoint for the P-9 permissive. The P-9 permissive enables the direct reactor trip from a turbine trip signal. Above the P-9 setpoint, the turbine trip signal will generate a reactor trip. Below the setpoint, it will not. NUREG-0737 Item II.3K.10 requires implementation of an anticipatory trip that will reduce the likelihood of core melt due to a small break LOCA by challenging the pressurizer PORV. This function is performed by the direct reactor trip from the turbine trip. With modifications to the current steam dump control setpoints and assuming two of the condenser dump valves are unavailable, the SPU analysis has demonstrated that a turbine trip below the current setpoint of 51% of rated thermal power will not result in a challenge to the PORVs. The SPU will have no impact on the likelihood of a PORV failure leading to a small break LOCA.

LR Sections 2.6.1 “Primary Containment Functional Design,” 2.8.5 “Accident and Transient Analyses,” and 2.9.2 “Radiological Analyses Using Alternate Source Term” document the evaluations of the impact of SPU on the FSAR accident analysis described in FSAR Chapter 6 and 15. The following modifications will be implemented to ensure the results of the accident analyses at SPU conditions will meet all requirements. These modifications are as follows:

- Implementation of new ECCS Cold Leg Injection Valve permissive
- Elimination of automatic rod withdrawal capability of the rod control system
- Installation of an electronic filter on the hot leg temperature RTD signal with associated changes to the over-temperature delta T and over-power delta T reactor trip setpoints
- Installation of an automatic initiation of the Control Room Emergency Ventilation system upon receipt of a Control Building Isolation Signal

In addition, improved NRC approved methodologies have been used in performance of the accident analyses. These include:

- WRB-2M DNBR correlation
- Westinghouse RETRAN for non-LOCA analyses
- Westinghouse VIPRE for Thermal Hydraulic analyses
- Dominion GOTHIC for Containment analyses
- Westinghouse Best Estimate ASTRUM Large Break LOCA methodology

Use of these up-to-date analysis methodologies provides improved predictions of the accident analysis response. All restrictions and limitations of these methodologies, including those identified by the NRC, have been met in the application of these methodologies to the MPS3 SPU accident analyses.

The updated SPU accident analyses as documented in the License Report, together with the implementation of the planned modifications, provide assurance there is no significant increase in the consequences of any analyzed accident.

6.1.1.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

New systems are not required to implement the proposed SPU, and new interactions among SSCs are not created. The SPU does not create new failure modes for existing SSCs. Modified components do not introduce failures different from those of the components in their pre-modified conditions. Consequently, no new or different accident sequences are introduced.

The increase in power level does not create new fission product release paths. The fission product barriers (Fuel cladding, reactor coolant pressure boundary, and the containment building) remain unchanged.

Operating procedure changes do not result in any significant changes in operating philosophy. Training will be provided to address SPU effects. For these reasons, the proposed power uprate does not introduce human performance issues that would create new accidents or different accident sequences.

Therefore, the proposed power uprate does not create the possibility of a new or different kind of accident from any previously evaluated**.**

6.1.1.3 Involve a significant reduction in a margin of safety.

As discussed in LR Sections 2.6.1, 2.8.5, and 2.9.2, the entire design basis limits for the containment analysis and the transient accident analysis are met at the SPU conditions. Thus, there is no significant reduction in the margin of safety.

This conclusion is based, in part, on the use of the NRC approved WRB-2M DNBR correlation. This correlation is more accurate for RFA/RFA-2 fuel design that is currently being used at MPS3 and will continue to be used upon implementation of the SPU. All restrictions and limitations, including those identified by the NRC have been applied in the SPU DNBR analysis. Thus, the use of the WRB-2M correlation does not result in a significant reduction in the margin of safety.

6.1.1.4 Conclusion

Therefore, there are no significant hazards associated with the change in rated thermal power.

6.1.2 Safety Limits

6.1.2.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

The change in the DNB limit corresponds to the change in the DNBR correlation. By meeting the DNBR limit, the DNBR analysis will continue to demonstrate that there is a 95% probability with a 95% confidence level that when the predicted

DNBR is greater than the limit, DNB will not occur. LR Section 2.8.5 shows that the appropriate DNBR criterion is met for accident analyses. Thus, it is concluded that use of the new DNB limit associated with the new DNBR correlation will not significantly increase the consequences of an accident.

Since the change in DNB limit is an analytical change only and has no impact on the operation of any system, it cannot affect the probability of any previously evaluated accident.

6.1.2.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

The change in DNB limit is an analytical change only and has no impact on the operation of any system. Thus, it cannot cause an accident or cause any failures that can create an accident of a different type.

6.1.2.3 Involve a significant reduction in a margin of safety.

The change in the DNB limit corresponds to the change in the DNBR correlation. By meeting the DNBR limit, the DNBR analysis will continue to demonstrate that there is a 95% probability with a 95% confidence level that when the predicted DNBR is greater than the limit, DNB will not occur. LR Section 2.8.5 shows that the appropriate DNBR criterion is met for all accident analyses. Since all of the appropriate DNB criteria are met, there is no impact on the fuel barrier and the associated margin of safety.

6.1.2.4 Conclusion

Therefore, there are no significant hazards associated with the change in the safety limits.

6.1.3 RCS Flow Rate

6.1.3.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

The SPU accident analyses documented in LR Sections 2.6.1 and 2.8.5 demonstrates that all design basis limits are met assuming the current thermal design flow of 363,200 gpm corresponding to a maximum of 10% SG tube plugging. Thus, in keeping with TSTF-339, the minimum RCS flow in Technical Specification 3.2.3.1 is being changed to 363,200 gpm. Since this is consistent with the SPU accident analyses, changing the RCS flow will not result in a significant increase in the consequences of an accident.

A Minimum Measured Flow of 379,200 gpm assuming all thimble plugs are removed has been used in the DNBR analysis. The Minimum Measured Flow together with the statistical combination of uncertainty analysis methodology (RTDP) has been applied to demonstrate that the appropriate DNBR criteria are met. In keeping with TSTF-339, the Minimum Measured Flow will be specified in the Core Operating Limits Report.

The RCS flow uncertainty calculation has been updated for SPU conditions and includes a re-validated drift allowance that covers the 18-month interval plus a 25% allowance. Since drift has been accounted for the full cycle operation, it is unnecessary to place a time restriction for performing the RCS flow measurement calibration in relationship to the calorimetric measurement. In addition, there is very little variation in actual RCS flow during steady state operation through the cycle. Since RCS flow changes very little between calibrations and the RCS flow uncertainty takes into account drift for the full cycle operation, this requirement can be deleted while still assuring that the RCS flow requirements will be met with no impact on the consequences of any accident.

The proposed change to the measurement limit and the time for performing the measurement calibration has no direct impact on the operation of the RC pumps or any other equipment. Both limits are met with the currently installed Reactor Coolant Pumps. The proposed change cannot increase the likelihood of any accident.

6.1.3.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

The proposed change to the measurement limit and the time for performing the measurement calibration has no direct impact on the operation of the RC pumps or any other equipment. Both limits are met with the currently installed Reactor Coolant Pumps. Thus the change cannot create a new or different kind of accident from any accident previously evaluated.

6.1.3.3 Involve a significant reduction in a margin of safety.

The accident analyses documented in LR Sections 2.6.1 and 2.8.5 demonstrate that all design basis limits are met assuming a thermal design flow of 363,200 gpm and a minimum measured flow of 379,200 gpm. Thus, the proposed change does not result in a reduction in a margin of safety.

6.1.3.4 Conclusion

Therefore, there are no significant hazards associated with the change in minimum RCS flow specified in the Technical Specifications.

6.1.4 P-8 Reactor Protection System Interlock

6.1.4.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

As documented in LR Section 2.8.5.3, an analysis has been performed for a partial loss of flow (single RC pump trip) from 60% power with no reactor trip. The DNBR analysis shows the minimum DNBR acceptance criterion is met. Thus, changing the P-8 reactor protection system interlock setpoint to 50% rated thermal power will not result in an increase in consequences of a partial loss of flow. Thus, this change does not increase the consequences of any evaluated accident.

By raising the P-8 setpoint from 37.5% to 50%, the change will reduce the likelihood of an unnecessary reactor trip for power within the range of 37.5% to 50%. The SPU analysis in Section 2.8.5.3 demonstrates that a reactor trip is unnecessary following a single RC pump trip below 50% power. Thus, this change will not significantly increase the probability of any evaluated accident.

6.1.4.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

The change in the P-8 setpoint does not change the function of P-8 RPS interlock or the hardware. The change does not create the possibility of a new or different kind of accident.

6.1.4.3 Involve a significant reduction in a margin of safety.

The SPU analysis documented in LR Section 2.8.5.3 demonstrates that there is no fuel failure following a single RC pump trip at 50% power. Thus, the change in P-8 setpoint does not result in a significant reduction in a margin of safety.

6.1.4.4 Conclusion

Therefore, there are no significant hazards associated with the change in the P-8 RPS interlock setpoint.

6.1.5 Over Temperature Delta Temperature (OTΔT) and Overpower Delta Temperature (OPΔT) Setpoints

6.1.5.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

The Over Temperature Delta Temperature (OTΔT) and Overpower Delta Temperature (OPΔT) reactor trip setpoints are credited in the analysis of a number of events (e.g., steam line break and rod withdrawal at power) to ensure that the DNBR criteria and the fuel temperature melt temperature limit are met. An additional consideration in determining the optimum OTΔT and OPΔT reactor trip setpoints is the potential for spurious alarms and trips due the temperature-spiking phenomenon known as Upper Plenum Anomaly. MPS3 has experienced pre-trip alarms due to this phenomenon. To minimize the potential for spurious alarms and trips, an electronic filter will be installed for the hot leg RTD temperature signal.

A scoping study was performed to determine the optimum OTΔT and OPΔT setpoints that will assure that the DNBR and fuel temperature melt limit are met while minimizing the likelihood for a spurious trip.

As shown in LR Section 2.8.5, the revised accident analyses demonstrate that all DNBR and fuel melt limits have been met. Thus, there is no significant increase in the consequences of an accident.

In the scoping study, the potential for increased temperature spikes were considered. With the installation of the hot leg RTD temperature filter and the revised OTΔT and OPΔT setpoints, it is expected that the margin for inadvertent pre-trip alarms and inadvertent trips will be comparable to current pre-uprate conditions. Thus, it is concluded that the installation of the hot leg temperature filter and OTΔT and OPΔT setpoints will assure that there is no significant increase in the probability of any evaluated accident.

6.1.5.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

The change in the OTΔT and OPΔT setpoints will be implemented by changes in the RPS cabinets. One of the electronic cards will be eliminated, since part of the OPΔT setpoint equation is no longer needed, and replaced with a standard filter card. Thus, these changes do not introduce any new failure modes.

The result of a failure of the new hot leg RTD filter is comparable to a failure of the RTD itself. Thus, installation of the filter does not introduce new failure modes.

Thus, these changes will not create the possibility of a new or different kind of accident.

6.1.5.3 Involve a significant reduction in a margin of safety.

As shown in LR 2.8.5 the SPU conditions in combination with the installation of the hot leg RTD filter and the modified OTΔT and OPΔT setpoints have been incorporated in the revised accident analysis. The results of these analyses show that the appropriate DNBR and fuel melt limit criteria have been met. Thus, these changes do not result in a significant reduction in the margin of safety.

6.1.5.4 Conclusion

Therefore, there are no significant hazards associated with the change in the OTΔT and OPΔT setpoints.

6.1.6 RCS Low Pressure Permissive for Opening the ECCS Charging Injection Valves Following a Safety Injection

6.1.6.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

The current analysis for an inadvertent ECCS actuation at power documented in the FSAR 15.5.1 shows that operator action within ten minutes is required to assure that at least one PORV is available to prevent water relief from the pressurizer safety valves for which they are not qualified. The time-frame will be reduced at the SPU conditions. Thus, it was decided to implement a modification that would increase the time for operator action.

A new Cold Leg Injection Permissive will be installed to provide additional time for the operator to mitigate an Inadvertent ECCS actuation. The pressurizer overfill following an inadvertent ECCS actuation is caused by ECCS injection by the centrifugal charging pumps. Upon receipt of the inadvertent safety injection actuation signal, the reactor will trip, letdown will be isolated and the charging pumps will align to take suction from the refueling water storage tank and inject into the RCS cold legs and the RC pump seals. However, activation of the Cold Leg Injection Permissive will be required to permit automatic opening of the charging pump ECCS injection valves. The Cold Leg Injection Permissive is activated when two of four low pressurizer pressure channels indicate less than 1900 psia. With an inadvertent SIAS and no other transient in progress, the RCS pressure will remain above 1900 psia. The Cold Leg Injection Permissive will prevent charging flow through the ECCS injection valves. Since RCS pressure will also be above the shutoff head for the High Pressure and Low Pressure Safety Injection Pumps, the only source of water addition to the RCS is the charging pump injection into the RC pump seals.

As shown in LR Section 2.8.5.5, with credit for the cold leg permissive, the operators will have at least 70.4 minutes (4225 seconds) to take action to prevent water relief through the pressurizer safety valves. Because of the long time available, operators will be able to terminate the RCS mass addition before the safety valves can be challenged. Alternatively, the operators can take actions to assure that at least one PORV is available to provide mitigation at 70.4 minutes as compared to the current value of 10.75 minutes (645 seconds).

Because of the significant increase in available operator action time, the time for action for the inadvertent ECCS actuation event no longer bounds the CVCS malfunction transient as stated currently in FSAR Section 15.5.2. Thus, the CVCS malfunction has been analyzed at the SPU conditions. As discussed in LR Section 2.8.5.5, it has confirmed that there is at least ten minutes for operator action to terminate the RCS injection following the limiting CVCS malfunction.

The design of the Cold Leg Injection Permissive will meet all of the required codes and standards such as IEEE 279. The design will be single failure proof to ensure that when RCS pressure drops below 1900 psia the Cold Leg Injection Permissive will activate to allow opening the charging injection valves so that injection will occur when required. A Failure Modes and Effects evaluation has been performed to assure that all failure modes are bounded by current failure modes and that no new failure modes have been introduced.

There are three different automatic actuation functions for SIAS. These are as follows:

- Pressurizer Pressure – Low with a nominal setpoint of 1892 psia
- Steam Line Pressure – Low with an nominal setpoint of 658.6 psig and
- Containment Pressure High 1 with a setpoint of 17.7 psia

Since the Cold Leg Injection Permissive is higher than the low pressurizer pressure SIAS setpoint, the Cold Leg Injection Permissive will be activated when the low pressurizer pressure SIAS setpoint is exceeded. Thus, the Cold Leg Injection Permissive will have no impact on the ECCS performance assumed for the LOCA analysis.

The low steam line pressure SIAS setpoint is credited in the SLB accident analysis for main feedwater and main steam isolation. However, for ECCS injection, the low pressurizer pressure SIAS setpoint is assumed to initiate ECCS. No credit is taken for the low steam line pressure SIAS setpoint for

ECCS initiation. Thus the Cold Leg Injection Permissive will have no impact on the ECCS performance assumed for the steam line break analysis.

ECCS actuation will also occur if containment pressure exceeds the high pressure setpoint of 17.7 psia. High containment pressure can result from either a LOCA or SLB. As discussed above, for both LOCA and SLB, the low pressurizer pressure SIAS setpoint is credited for initiation of ECCS injection for both the core response and the containment analysis. No credit is taken for the high containment pressure actuation. Thus, the Cold Leg Permissive will have no impact on the ECCS performance assumed both in the core response and the containment response following a LOCA or steam line break.

While the current licensing basis analysis only requires evaluation of the inadvertent ECCS actuation event at power operation, the proposed Technical Specification mode requirements for the Cold Leg Injection Permissive match the mode requirements for automatic actuation of ECCS. This will insure the Cold Leg Injection Permissive will provide protection for all the modes where automatic actuation of ECCS is required.

Thus, it is concluded that the addition of the new Cold Leg Injection Permissive will have no significant impact on the consequences of any previously evaluated accident.

The Cold Leg Injection Permissive only affects charging when charging is in the ECCS lineup. It will have no impact on normal charging operation. A failure of the cold leg injection permissive by itself cannot cause charging to inject through the ECCS pathway. It will become activated only when RCS pressure reaches the low pressurizer pressure reactor trip setpoint and cannot affect normal operation. Thus, the change does not result in a significant increase in probabily or consequence of an analyzed accident.

6.1.6.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

The Cold Leg Injection Permissive will be activated at a RCS pressure that is higher than the low pressurizer pressure safety injection setpoint. The new permissive will be single failure proof and designed to meet all the appropriate codes and standards. A failure of the Cold Leg Injection Permissive will not affect the ECCS. Thus, it will not create the possibility of a new or different kind of accident.

6.1.6.3 Involve a significant reduction in a margin of safety.

As documented in LR Sections 2.6.1 and 2.8.5, all containment and core design basis requirements are met assuming the installation of the Cold Leg Injection Permissive at SPU conditions. The Cold Leg Injection Permissive will increase the available time for operator action to mitigate an Inadvertent SIAS actuation by approximately a factor of 7. Thus, the change does not involve a significant reduction in the margin of safety.

6.1.6.4 Conclusion

Therefore, there are no significant hazards associated with the addition of the Cold Leg Injection Permissive.

6.1.7 Control Building Isolation

6.1.7.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

The current Technical Specification requires the OPERABILITY of the automatic Control Building Isolation and Control Room Emergency Ventilation system in Modes 5 and 6 as well as Modes 1 through 4 and during fuel movement. As documented in LR Section 2.8.5, the only accident analyses relevant to Mode 5 and 6 are the boron dilution and the fuel handling accident. As seen in LR Section 2.8.5.4, there is no fuel damage from a boron dilution event in Mode 5 and procedural controls provide assurance that a boron dilution event will not occur in Mode 6. For the fuel handling accident, the requirement for OPERABILITY of the automatic Control Building Isolation and Control Room Emergency Ventilation system is met by maintaining the requirement for OPERABILITY during fuel movement. Further, as discussed in LR Section 2.9.2 radiological analyses have been performed for the movement of non-fuel components (e.g., control rods, sources and thimble plugs) in the spent fuel. The analyses show acceptable operator doses with no credit for either Control Building Isolation or the Control Room Emergency Ventilation system. Thus, it is concluded that eliminating Modes 5 and 6 from the operability requirements for Control Building Isolation and Control Room Emergency Ventilation system will not significantly increase the consequences to the public or the control room operators from any evaluated accident.

6.1.7.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

The change only affects the Control Building Isolation and the Control Room Emergency Ventilation system. These components and system cannot initiate a plant transient. Thus the change does not create the possibility of a new or different kind of accident.

6.1.7.3 Involve a significant reduction in a margin of safety.

LR Section 2.9.2 demonstrates that the control room operator and public doses will be met for all accidents and transients required to be postulated with no credit for the OPERABILITY of the Control Building Emergency Ventilation system or Control Building Isolation in Modes 5 and 6. The analysis in LR Section 2.8.5.4 shows that there are no radioactive releases from a boron dilution event. The requirement for OPERABILITY of the Control Building Emergency Ventilation system and the Control Building Isolation will be retained for fuel movement. LR Section 2.9.2 demonstrates that the Control Building Isolation and Control Room Emergency Ventilation system are not required for movement of non-fuel components in the spent fuel pool. Thus, the change does not involve a significant reduction in the margin of safety.

6.1.7.4 Conclusion

Therefore, there are no significant hazards associated with the elimination of the requirement for OPERABILITY of Control Building Isolation and the Control Room Emergency Ventilation system in Modes 5 and 6.

6.1.8 Pressurizer Level

6.1.8.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

As documented in LR Sections 2.6.1 and 2.8.5, all design basis limits are met for the containment and accident analysis at SPU conditions, assuming an increase in the maximum nominal pressurizer level to 64%. These analyses also have taken into account a pressurizer level uncertainty of +/- 7.6% where appropriate. Thus, the change in pressurizer level does not significantly increase the consequences of any accident.

Raising the initial pressurizer level provides assurance that the pressurizer heaters will remain covered and letdown will remain in service following a routine reactor trip. Thus, there is no increase in the probability of a pressurizer heater failure causing an RCS leak or of an inadvertent letdown isolation that can lead to an RCS overfill event.

As documented in LR Section 2.4.2, the control systems will be able to mitigate the operational transients without requiring a reactor trip or SIAS actuation assuming operation at the revised pressurizer level program. This evaluation addresses coastdown as well as the full range for Tave. Thus, the change does not significantly increase the probability of any evaluated accident.

6.1.8.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

The change in the pressurizer level program will be implemented with the existing hardware. Thus, the change does not introduce any new failure modes. Thus, the change does not create the possibility of a new or different kind of accident.

6.1.8.3 Involve a significant reduction in a margin of safety.

The revised pressurizer level program assures that the pressurizer heaters will remain covered during routine reactor trip. This provides assurance that the heaters will not fail and will not adversely affect the RCS pressure boundary integrity. As documented in LR Sections 2.6.1 and 2.8.5, all design basis requirements for the containment and accident analyses are met assuming the revised pressurizer level program. Thus, the change does not result in a significant reduction in the margin of safety.

6.1.8.4 Conclusion

Therefore, there are no significant hazards associated with the revised pressurizer level program.

6.1.9 Turbine Cycle

6.1.9.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

As documented in LR Section 2.8.4.2, the maximum allowed power level with inoperable Main Steam Safety Valves (MSSVs) has been re-calculated to take into account SPU conditions. In order to preclude secondary side overpressurization in the event of a Loss of Load or Turbine Trip event, the maximum power level allowed for operation with inoperable MSSVs must be below the heat removing capability of the operable MSSVs. The same algorithm for calculation the maximum power level used for current limits was used to calculate the revised limits at SPU conditions. The algorithm uses the nominal NSSS power rating of the plant, the minimum total steam flow rate capability of the operable MSSVs on any one steam generator at the highest MSSV opening pressure and the heat of vaporization at the highest MSSV opening pressure.

The lowest flow available from the operable valves and the lowest heat of vaporization at the highest set pressure are used to provide the most conservative setpoint values. The calculation also accounts for a 9% uncertainty in the reactor trip setpoint. The limits specified in Technical Specification Table 3.7-1 are being changed to match the revised analyses. These new limits provide assurance that the secondary side pressure limits will be met for the limiting overpressurization event even with inoperable MSSVs. Thus, the change will assure that there is no significant increase in the consequences of any evaluated accident.

The Action Statements in Technical Specification 3.7.1.1 have been revised to match the Improved Standard Technical Specifications. Implementation of the Action Statements will continue to provide assurance that the operating power level will be limited with inoperable MSSVs and consequently there will be no impact on the likelihood of failure of the secondary side pressure boundary. Thus, there is no significant increase in the probability of any evaluated accident.

6.1.9.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

The revised power limitations and neutron flux high setpoints will be implemented using the same hardware. Thus, the change does not introduce any new failure modes. The change does not create the possibility of a new or different kind of accident.

6.1.9.3 Involve a significant reduction in a margin of safety.

The analysis documented in LR Section 2.8.4.2 shows that, with the revised limits on power level, the secondary side pressure limit will be maintained with inoperable MSSVs. The same methodology was used in determining the revised limits at SPU conditions. Thus, the change does not involve a significant reduction in the margin of safety.

6.1.9.4 Conclusion

Therefore, there are no significant hazards associated with the revised power level limits specified in Technical Specification Table 3.7-1 or the other changes made to Technical Specification 3.7.1.1.

6.1.10 Turbine Building Temperature Monitoring

6.1.10.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

Currently there are two groups of components in the turbine building that are included on the Master List of Environmentally Qualified Electrical Equipment. These are:

- Pressure transmitters PT 505 and 506 that measure first stage pressure
- Valve position switches MSS ZS59, 60, 61 and 62 for the main steam turbine stop valves

The first stage turbine pressure is used to set the demand signal for Tave. The rod control system is designed to maintain the Tave generated from the first stage turbine pressure signal. If the first stage turbine pressure transmitters were to fail, it could result in control rod movement. If the transmitters were to fail high such that the demand signal for Tave increases, under the current design, the control rods would withdraw in order to raise Tave. However, as part of the SPU, a modification is being implemented to eliminate the automatic rod withdrawal capability of the rod control system. With this control rod system modification, the control rods would not respond to a false demand for an increase in Tave.

If the transmitters were to fail low such that the demand signal for Tave decreases, the control rods would insert and shutdown the plant. This is the desired condition for a steam line break in the turbine building.

With the planned modification to the rod control system, there is no adverse impact of removing pressure transmitters PT-505 and PT-506 from the Master List. The steam line break analysis described in LR Section 2.8.5.1 will continue to remain valid and there will be no significant increase in the consequences of any accident.

No longer maintaining PT-505 and PT-506 as qualified for a steam line break in the Turbine Building may mean that these transmitters could fail causing a reactor trip. However, since a reactor trip for a steam line break in the turbine building is expected, this does not impact the overall likelihood of reactor trips. Thus, it is concluded that the change will not significantly increase the likelihood of any accident.

Valve position switches MSS ZS59, 60, 61 and 62 for the main steam turbine stop valves provide the turbine trip signal to the reactor protection system. No longer maintaining these switches on the Master List may mean that these switches could fail to generate the turbine trip signal following a steam line break in the turbine building. However, as shown in LR Section 2.8.5.1, all design basis requirements for mitigating steam line breaks are met without crediting the reactor trip from turbine trip. In fact, this trip function is not credited for any of the safety analyses. As discussed in LR Section 2.8.5.1, there are several different reactor trip functions that provide protection from steam line breaks, including low pressurizer pressure, low steam line pressure, high neutron flux and OTΔT. Thus, it is concluded that removing these switches from the Master List will not result in a significant decrease in the reliability of the Reactor Protection System or cause a significant increase in the probability of any accident.

As a result of these evaluations, a change will be made to remove these components from the Master List. There will no longer be any equipment in the turbine building requiring qualification for a steam line break in the turbine building. Thus, it is proposed to remove the TS requirement for temperature monitoring in the turbine building.

The TS requirement for temperature monitoring in the turbine building is to assure that the equipment qualification environmental profile remain bounding for the qualified equipment in the turbine building. With the removal of the two groups of equipment from the Master List, there will be no qualified equipment in the turbine building and the TS requirement for temperature monitoring can removed with no significant increase in the consequences or probability of any evaluated accident.

6.1.10.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

Removal of the requirement for temperature monitoring in the turbine building and in of itself cannot cause a transient. As discussed above, a change will be processed to remove the two groups of equipment currently maintained environmentally qualified. With the installation of a modification that will prevent automatic rod withdrawal by the rod control system, it is no longer necessary to maintain qualification for this equipment. Steam line breaks in the turbine building will still be bounded by the analysis provided in LR 2.8.5.1. The change will not create the possibility of a new or different kind of accident.

6.1.10.3 Involve a significant reduction in a margin of safety.

With the elimination of the capability of automatic rod withdrawal by the rod control system, a steam line break in the turbine building will not result in a power increase due to rod withdrawal. In the SPU steam line break analysis documented in LR Section 2.8.5.1, no credit is taken for environmentally qualified equipment in the turbine building for mitigation of a steam line break. Thus, removal of PT 505 and PT506 and switches MSS ZS59, 60, 61 and 62 from the

Master List will not affect the margin of safety maintained for steam line breaks. Thus, the change does not involve a significant reduction in the margin of safety.

6.1.10.4 Conclusion

Therefore, there are no significant hazards associated with elimination of the requirement for temperature monitoring in the turbine building.

6.1.11 Spent Fuel Pool Requirements

6.1.11.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

As discussed in LR Section 2.8.6.2 and Westinghouse report WCAP-16721-NP “Spent Fuel Criticality Safety Analysis”, revised spent fuel pool criticality analyses were performed to take into account the potential for more reactive fuel at SPU conditions. There are three different regions defined in the MPS3 spent fuel pool.

- Region 1 – 350 storage locations
- Region 2 – 673 storage locations
- Region 3 – 756 storage locations

Because of the potential for requiring more fresh assemblies to be loaded in the core every cycle, some of the assemblies to be discharged to the spent fuel pool may not have sufficient burnup to meet the requirements of Region 2. It may be necessary to temporarily store the discharge assemblies in Region 1. To limit the time that these assemblies need to be stored in Region 1, additional curves have been added to TS Figure 3.9-3 that specify the burnup limits as a function of enrichment, burnup, and decay time. These decay time curves provide assurance that all spent fuel pool criticality limits will be met.

The spent fuel pool criticality analysis also shows that more limiting burnup requirements are necessary for Region 3 for the assemblies used at the uprate power level. Thus, a new curve is being added to address these requirements for Region 3.

With these changes, the spent fuel pool criticality analysis documented in LR Section 2.8.6.2 and WCAP-16721-NP, shows that the changes do not increase the consequences of any accident.

The new TS limitations provide assurance that the spent fuel pool will remain subcritical for all future cycles at the SPU condition and there is no increase in the probability of a criticality accident. Thus, the changes do not significantly increase the probability of any analyzed accident.

6.1.11.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

The changes will be implemented with existing spent pool racks. Thus, no new failure modes are introduced. The proposed additional requirements and the SPU fuel criticality analysis provide assurance that the spent fuel pool will remain subcritical for all uprate cycles. Thus, the changes do not create the possibility of a new or different accident.

6.1.11.3 Involve a significant reduction in a margin of safety.

The analysis documented in LR Section 2.8.6.2 and WCAP-16721-NP shows that all spent fuel criticality limits are met and that there is no significant reduction in the margin of safety for the spent fuel pool.

6.1.11.4 Conclusion

Therefore, there are no significant hazards associated with the changes in the spent fuel pool requirements.

6.1.12 Peak Calculated Containment Internal Pressure

6.1.12.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

As documented in LR Section 2.6.1, the design basis LOCA analyses inside containment were performed using the NRC approved methodology at the SPU conditions. Results of these analyses continue to satisfy the event acceptance criteria. Components and systems will continue to function as designed and performance requirements for these systems will continue to be satisfied. Additionally, the proposed change to the calculated containment internal pressure for the design basis LOCA will not initiate any accident. Therefore, the proposed change does not significantly increase the probability or consequences of an accident previously evaluated.

6.1.12.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed change to the calculated containment internal pressure for the design basis LOCA. The proposed change has no adverse effect on any safety-related system and does not change the performance or integrity of any safety-related system. Additionally, no new safety-related equipment is being added or replaced as a result of the proposed change. Therefore, the possibility of a new or different kind of accident is not created.

6.1.12.3 Involve a significant reduction in a margin of safety.

The analyses documented in LR Section 2.6.1 continue to satisfy the acceptance criteria with respect to containment functional design and there is no significant reduction in the margin of safety for the containment.

6.1.12.4 Conclusion

Therefore, there are no significant hazards associated with the change in peak calculated containment pressure.

6.1.13 Large Break LOCA Methodology

6.1.13.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

As documented in LR Section 2.8.5.6, the best estimate ASTRUM analysis methodology has been applied to the Large Break LOCA analysis at SPU conditions. The analysis methodology provides more accurate estimates of peak clad temperature and other parameters associated with large break LOCA analyses. This methodology has been reviewed and approved for use by the NRC. In performing the MPS3 analyses, all limitations and restrictions of the methodology have been met, including those specified by the NRC. The results given in LR Section 2.8.5.6 show that all requirements of 10 CFR 50.46 have been met. Thus, the change in methodology does not significantly increase the probability or consequences of any analyzed accident.

6.1.13.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

The changes involve the methodology used to calculate core response following a large break LOCA. There are no changes in hardware and consequently no new failure modes. An analytical methodology change cannot create the possibility of a new or different kind of accident.

6.1.13.3 Involve a significant reduction in a margin of safety.

As documented in LR Section 2.8.5.6, the best estimate ASTRUM Large Break LOCA analysis results meet all requirements of 10 CFR 50.46. The NRC has approved this methodology and all limitations and restrictions have been met in applying the methodology to MPS3. Thus, the change does not involve a significant reduction in the margin of safety.

6.1.13.4 Conclusion

Therefore, there are no significant hazards associated with the change in the large break LOCA methodology.

6.1.14 Safety Grade Cold Shutdown (SGCS)

6.1.14.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

As documented in LR Section 2.8.4.4, the results of the evaluation continue to satisfy the SGCS cooldown times as required by BTP RSB 5-1. Components and systems that could be affected by the proposed change will continue to function as designed and performance requirements for these systems will continue to be satisfied and no safety limits will be exceeded. This is based upon the proposed design change that increases reactor plant component cooling water system operating temperatures during cooldown mode of operation. Additionally, the proposed licensing basis change related to SGCS was not found to initiate any accident, and therefore, does not increase the probability of an accident. Therefore, the proposed change does not significantly increase the probability or consequences of an accident previously evaluated.

6.1.14.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed licensing basis change related to SGCS. The proposed change has no adverse effect on any safety-related system and does not change the performance of or integrity of any safety-related system. Additionally, no new safety-related equipment is being added as a result of the proposed licensing basis change. Therefore, the possibility of a new or different kind of accident is not created.

6.1.14.3 Involve a significant reduction in a margin to safety.

As documented in LR Section 2.8.4.4, the evaluation supporting the proposed licensing basis change continues to satisfy the appropriate acceptance criteria. Therefore, the proposed licensing basis change does not involve a significant reduction in a margin of safety.

6.1.14.4 Conclusion

Therefore, there are no significant hazards associated with the SGCS licensing basis change.

6.1.15 BTP CMEB 9.5.1, Sections 5.c.3 and 5.c.5 Deviations

6.1.15.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

The proposed licensing basis change proposes an alternate fire shutdown strategy for long-term SG inventory make-up that does not rely upon seawater. Instead, the DWST and CST will be replenished with make-up water from sources such as domestic water, demineralized water and firewater. The proposed change does not affect the inputs or assumptions for any accidents previously evaluated nor does it affect the initiation of a fire event. Therefore, the proposed change to the licensing basis does not increase the probability or consequences of an accident previously evaluated.

6.1.15.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

The proposed licensing basis change eliminates credit of service water as additional means of replenishing auxiliary feedwater for SG make-up. This proposed change does not introduce new failures or new malfunctions that would cause a new or different kind of accident or fire event. The potential for increased water usage due to the proposed change in fire mitigation strategy is within the capability and capacity of the existing domestic water, firewater and demineralized water systems. Therefore, the proposed change to the licensing basis does not create the possibility of a new or different kind of accident from any accident previously evaluated.

6.1.15.3 Involve a significant reduction in a margin of safety.

The evaluated fire event assumes a fire coincident with a loss of power, with no additional plant accidents. The current credit for service water for additional long-term SG make-up is being eliminated. However, the proposed change credits other sources of water (domestic water, demineralized water or firewater to replenished the DWST and CST). This improves the reliability of a fission product barrier (i.e., Stem Generator Tube Integrity) since it eliminates the potential degradation of the Steam Generator tubes by service water as a salt water source. Therefore, based on the above, the proposed licensing basis change does not involve a significant reduction in a margin of safety.

6.1.15.4 Conclusion

Therefore, there are no significant hazards associated with the licensing basis change associated with BTP CMEB 9.5-1.

6.1.16 DWST Licensing Basis Change

6.1.16.1 Involve a significant increase in the probability or consequences of an accident previously evaluated.

The proposed licensing basis change will ensure that sufficient inventory to maintain the reactor coolant system at HOT STANDBY condition for 7-hours (instead of 10 hours currently required) with steam discharged to the atmosphere, concurrent with a total loss-of-offsite power, and with an additional 6-hour cooldown period to reduce reactor coolant temperature to 350° F. The Technical Specification 3.7.1.3 limiting condition for operation (i.e., a 334,000-gallon measured volume) is unchanged. The proposed licensing basis will continue to provide sufficient DWST inventory for safety grade cold shutdown (i.e., BTP RSB 5-1 compliance) and station blackout. The AFW system and components (i.e., DWST) will continue to perform their design functions and no safety limits will be exceeded. Additionally, the proposed licensing basis change was not found to initiate any accident, and therefore, does not increase the probability of an accident. Since the AFW System performance acceptance criteria are satisfied, the proposed licensing basis does not increase the consequences of an accident.

6.1.16.2 Create the possibility of a new or different kind of accident from any accident previously evaluated.

No new accident scenarios, failure mechanisms, or limiting single failures are introduced as a result of the proposed licensing basis change. The proposed change has no adverse effect on any SSC or integrity of any safety-related system. The AFW system can continue to perform its design functions. Additionally, no new safety-related equipment is being added or replaced as a result of the proposed licensing basis change. Therefore, the possibility of a new or different kind of accident is not created.

6.1.16.3 Involve a significant reduction in a margin of safety.

The evaluations documented in LR Section 2.5.4.5 demonstrate the AFW System continues to meet AFW system performance acceptance criteria. The proposed licensing basis change retains the allowance for uncertainties, spillage and unusable inventory. This change does not result in exceeding or altering a design basis or safety limit. Therefore, there is no significant reduction in a margin of safety.

6.1.16.4 Conclusion

Therefore, there are no significant hazards associated with the licensing basis change related to the DWST requirements.

6.1.17 Significant Hazards Conclusion

Based on the above, DNC concludes that the proposed license amendment request 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.

6.2 Applicable Regulatory Requirements/Criteria

The proposed changes have been evaluated to determine whether applicable regulations and requirements continue to be met.

DNC has determined that the proposed changes do not require any exemptions or relief from regulatory requirements, other than the Operating License, and do not affect conformance any General design Criterion (GDC) differently than described in the MPS3 FSAR.

7.0 Environmental Evaluation

The environmental considerations evaluation is contained in Attachment 2, Supplemental Environmental Report. It concludes that the SPU will not result in a significant adverse change in the environmental impacts of MPS3 operation.

The proposed license amendment request does not involve a significant adverse change in the types or the amounts of any effluent that may be released offsite nor does it involve a significant increase in individual or cumulative occupational radiation exposure.