SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 242 TO RENEWED FACILITY OPERATING

LICENSE NO. NPF-49

DOMINION NUCLEAR CONNECTICUT, INCORPORATED

MILLSTONE POWER STATION, UNIT 3

DOCKET NO. 50-423

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1.0 INTRODUCTION

1.1 Application

By letter dated July 13, 2007,[1] as supplemented by additional letters,[2] Dominion Nuclear Connecticut, Inc. (DNC), licensee of Millstone Power Station, Unit 3 (MPS3), submitted the application, "Dominion Nuclear Connecticut, Inc., Millstone Power Station Unit 3, License Amendment Request, Stretch Power Uprate," to the U.S. Nuclear Regulatory Commission (NRC).

The proposed license amendment would allow an increase in the maximum authorized power level from the current licensed thermal power (CLTP) level of 3,411 megawatts thermal (MWt) to 3,650 MWt, and make changes to the facility operating license and technical specifications, as necessary, to support operation at the stretch power level, which is an increase of approximately 7 percent. The proposed increase in power level is considered a stretch power uprate (SPU).

The supplemental letters dated January 10 (4 letters), January 11 (4 letters), January 14, January 18 (5 letters), January 31, February 25 (2 letters), March 5, March 10 (2 letters), March 25, March 27, April 4, April 24, April 29, May 15, May 20, May 21, July 10, and July 16, 2008, provided additional clarifying information that did not expand the scope of the initial application and did not change the NRC staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on January 15, 2008 (73 FR 2549).

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[1] DNC Letter (07-450) to the NRC, "Dominion Nuclear Connecticut, Inc., Millstone Power Station Unit 3 License Amendment Request, Stretch Power Uprate," dated July 13, 2007 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML072000386).

[2] Supplemental Letters dated: July 13, 2007 (ML072000281); September 12, 2007 (ML072570061); November 19, 2007 (ML073230976); December 13, 2007 (ML073480240); December 17, 2007 (ML073520051); January 10, 2008 (ML080100600, ML080100604, ML080100606, ML080100611); January 11, 2008 (ML080110695, ML080140077, ML080170495, ML080580476); January 14, 2008 (ML080140570); January 18, 2008 (ML080220506, ML080220527, ML080220530, ML080220541, ML080280375); January 31, 2008 (ML080320308); February 25, 2008 (ML0805 60392, ML080560615); March 5, 2008 (ML080660108); March 10, 2008 (ML080710377, ML080710391); March 25, 2008 (ML080850894); March 27, 2008, ((ML080880268); April 4, 2008 (ML081430014); April 24, 2008 (ML081150679); April 29, 2008 (ML081200643); May 15, 2008 (ML081360625); May 20, 2008 (ML081420443); May 21, 2008 (ML081420824); July 10, 2008 (ML081930274); and July 16, 2008 (ML081990112).

1.2 Background

MPS3 uses a 4-Loop, closed cycle, pressurized-water reactor (PWR) type nuclear steam supply system (NSSS) furnished by Westinghouse Electric Corporation and a turbine-generator furnished by the General Electric Company (GE). The architect-engineer was Stone & Webster Engineering Corporation. MPS3 has a sub-atmospheric reactor containment.

The site, approximately 500 acres in area, is on the north shore of Long Island Sound and on the east side of Niantic Bay. It is located in the Town of Waterford, Connecticut, about 3.2 miles west-southwest of New London and about 40 miles southeast of Hartford. The surrounding area is primarily residential with some commercial and industrial uses.

The construction permit for MPS3 was issued on August 9, 1974. The full-term operating license, as well as the full-power license, were issued on January 31, 1986, for operation at 3,411 MWt. MPS3 was at 100 percent power on April 17, 1986, and entered commercial operation on April 23, 1986.

In 2001, Millstone Power Station (MPS), Units 1, 2 and 3 operating licenses were transferred from Northeast Nuclear Energy Company to DNC. DNC is an indirect wholly-owned subsidiary of Dominion Energy, which is in turn owned by Dominion Resources, Inc. (DRI). Virginia Power, which is the licensed owner and operator of the North Anna and Surry Nuclear Stations, is also a subsidiary of DRI.

DNC filed for renewal of the MPS2 and MPS3 operating licenses in January 2004. In July 2005, the NRC issued NUREG-1437, "Generic Environmental Impact Statement for the Renewal of Nuclear Power Plants,"[3] Supplement 22, for license renewal for the two units. The staff's review and its acceptance of the license renewal application (LRA) are documented in staff's SE report, NUREG-1838.[4] The renewed operating license for MPS2 now expires on July 31, 2035, while the MPS3 renewed operating license now expires on November 25, 2045. MPS1 permanently ceased operation on July 21, 1998, and is currently being decommissioned.

A new permissive (P-19) will be added to monitor low reactor coolant system (RCS) pressure during the fall 2008 refueling outage and before implementation of the SPU amendment. The P-19 permissive is designed to permit the cold leg injection valves to open automatically upon receiving a safety injection signal. The permissive will be derived utilizing the existing low pressurizer pressure reactor trip two out of four bistable trip logic and will have the same set point as that function. Within the MPS3 solid state protection cabinets, the signal will be separated from the reactor trip function logic to develop the low RCS pressure, cold leg injection permissive. The cold leg injection permissive relay contacts will be placed in series with the safety injection relay contacts in the control logic for the cold leg injection valves, to permit them to open automatically upon receiving both the safety injection signal and the cold leg injection permissive. Using the low pressurizer pressure reactor trip bistable trip logic helps to maintain diversity from the low pressurizer pressure safety injection bistable trip logic to the extent possible.

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[3] ADAMS Accession No. ML051990002

[4] "Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, Docket Nos. 50-336 and 50-423, Dominion Nuclear Connecticut, Inc.," (ADAMS Accession No. ML053270483).

1.3 Licensee's Approach

The licensee's application for the proposed SPU follows the guidance in the Office of Nuclear Reactor Regulation's (NRR's) Review Standard (RS)-001, "Review Standard for Extended Power Uprates,"[5] to the extent that the review standard is consistent with the design basis of the plant. Where differences exist between the plant-specific design basis and RS-001, the licensee described the differences and provided evaluations consistent with the design basis of the plant.

Since MPS3 has a renewed license, DNC performed an evaluation of the SPU impact on the extended period of plant operation. The purpose of the evaluation was to identify which, if any, structures, systems, and components (SSCs) warranted additional aging management action because of new aging effects due to the changes in the operating environment resulting from SPU or the addition of, or modification to, components relied upon to satisfy SPU operating conditions. SSCs relied upon for achieving the license renewal scoping objectives were evaluated within the structure or system that contains them. DNC also evaluated the potential impact of the proposed SPU on license renewal Time-limited Aging Analyses (TLAA). Specifically, the evaluation considered any new aging effects or increases in degradation rates potentially created by the new SPU operating parameters.

The licensee reviewed the MPS3 design in accordance with the July 1981 Edition of the "Standard Review Plan (SRP) for the Review of Safety Analysis Report for Nuclear Power Plants," dated July 1981,(NUREG-0800)[6], Section 5.3.1, Rev. 1. As noted in the updated final safety analysis report (UFSAR) Section 3.1, the design bases of MPS3 are measured against the NRC General Design Criteria (GDC) for Nuclear Power Plants, of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix A, as amended through October 27, 1978.

The licensee plans to implement the SPU in one step. The licensee plans to make minor modifications necessary to implement the SPU during the refueling outage (RFO) in fall 2008. Subsequently, the plant will be operated at 3,650 MWt starting in Cycle 13.

1.4 Plant Modifications

The licensee has determined that several plant modifications are necessary to implement the proposed SPU. The following is a list of modifications that the licensee proposes to complete during the fall 2008 RFO:

(1) Replace the turbine for the main feedwater pump;

(2) Modify ductwork to provide additional ventilation cooling in the condensate pump area for the turbine building heating, ventilation, and air-conditioning (HVAC) system;

(3) Provide control building auto initiation of pressurized filtration following a control building isolation (CBI) signal for the control building ventilation;

[5] ADAMS Accession No. ML023610659
[6] ADAMS Accession No. ML033580033

(4) For the turbine generator, provide the following: (a) control valve position demand against lift settings for the valve position cards; (b) changes to power load imbalance circuits; (c) sensor rescaling for steam pressure changes; (d) instrument scaling; and (e) main control board meter scale changes;

(5) Increase the piping design temperature between residual heat removal (RHR) and component cooling water (CCW) heat exchanger for the CCW system;

(6) For the instrumentation and controls (I&C) systems, provide set point changes to the following: (a) balance-of-plant (BOP) systems; (b) feedwater pump; (c) pressurizer level control; (d) electronic filter on the T_{hot} signal; (e) pressurizer relief tank (PRT) level alarm; (f) condenser steam dump trip valve control; and (g) P-8 set point change;

(7) Pipe support modifications for the condensate system, feedwater system, CCW system, and containment recirculation;

(8) Provide a permissive for opening cold leg injection valves for the emergency core cooling system (ECCS);

(9) Provide instrument loop rescaling for the following: first stage turbine pressure; and

(10) Deletion of automatic rod withdrawal capability for the rod control system.

The NRC staff's evaluation of the licensee's proposed plant modifications is provided in Section 2.0 of this safety evaluation.

1.5 Method of NRC Staff Review

The NRC staff used previously-approved SPUs, along with RS-001[7] for guidance. An extended power uprate (EPU) review includes the following areas: materials and chemical engineering; mechanical and chemical engineering; electrical engineering; I&C; containment review considerations; habitability, filtration, and ventilation; reactor systems; source terms and radiological consequences analyses; human performance; health physics; risk evaluation; and power ascension and test plan. As described in this memorandum, an SPU includes the same areas as an EPU except for health physics, risk evaluation, and power ascension and test plan.

The NRC staff reviewed the licensee's application to ensure that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner; (2) activities proposed will be conducted in compliance with the Commission's regulations; and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public. The purpose of the NRC staff's review is to evaluate the licensee's assessment of the impact of the proposed SPU on design-basis analyses. The NRC staff evaluated the licensee's application and supplements.

[7] RS-001, "Review Standard for Extended Power Uprates," dated December 2003 (ADAMS Accession Number ML033640024)

In areas where the licensee and its contractors used NRC-approved or widely accepted methods in performing analyses related to the proposed SPU, the NRC staff reviewed relevant material to ensure that the licensee/contractor used the methods consistent with the limitations and restrictions placed on the methods. In addition, the NRC staff considered the affects of the changes in plant operating conditions on the use of these methods to ensure that the methods are appropriate for use at the proposed SPU conditions. Details of the NRC staff's review are provided in Section 2.0 of this safety evaluation.

An audit of the Rod Withdrawal at Power (RWAP) overpressure analysis supporting the SPU was also conducted. The result of the audit is discussed in section 2.8 of this safety evaluation.

Independent NRC staff calculations were performed in relation to the following topics:

- The staff performed an independent calculation of the end of life (EOL) upper-shelf energy (USE) values for the MPS3 reactor vessel (RV) beltline materials using the limiting 54 effective full-power year (EFPY) neutron fluence value for the one-quarter of the RV wall thickness (1/4T) location for the SPU conditions.

- The staff performed an independent calculation of the EOL RTPTS values for MPS3 using the 54 EFPY neutron fluence value for the clad-metal interface location of the vessel at SPU conditions.

- The NRC staff used the RADTRAD computer code to perform independent confirmatory dose evaluations.

The results of the calculations are discussed in Section 2.0 of this safety evaluation.

2.0 EVALUATION

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Material Surveillance Program

Regulatory Evaluation

The RV material surveillance program provides a means for determining and monitoring the fracture toughness of the RV beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the RV. The NRC staff's review primarily focused on the effects of the proposed SPU on the licensee's RV surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on: (1) General Design Criterion (GDC)-14, insofar as it requires that the reactor coolant pressure boundary (RCPB) be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating; (2) GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix H, which provides for monitoring changes in the fracture toughness properties of materials in the RV beltline region; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix H. Specific review criteria are contained in SRP Section 5.3.1 and other guidance provided in Matrix 1 of RS-001.

Technical Evaluation

The NRC's regulatory requirements related to the establishment and implementation of a facility's RV materials surveillance program and surveillance capsule withdrawal schedule are given in 10 CFR Part 50, Appendix H. By reference, 10 CFR Part 50, Appendix H invokes the guidance in American Society for Testing and Materials (ASTM) Standard Practice E185, "Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels." ASTM Standard Practice E185 provides guidelines for designing and implementing the RV materials surveillance programs for operating light-water reactors, including guidelines for determining RV surveillance capsule withdrawal schedules based on the vessel material predicted transition temperature shifts (ΔRT_{NDT}).

The surveillance capsule withdrawal schedule shown in Table 2.1.1-3 of the SPU Licensing Report (LR) was prepared in terms of EFPY of plant operation with a projected design life of 32 EFPY. To date, three surveillance capsules were withdrawn, and the neutron fluence projections were updated using the third surveillance capsule. The licensee stated that the neutron fluence value obtained from the latest (third) surveillance capsule exceeded the projected neutron fluence value for the license renewal period (54 EFPY) under the SPU conditions. Therefore, the licensee concluded that the current surveillance capsule withdrawal schedule is still valid for the SPU conditions, and it meets the intent of ASTM E185. Consistent with the requirements specified in paragraph 7.6.2 of the ASTM E185, the licensee stated that the next capsule (standby capsule Z) will be withdrawn when the projected neutron fluence value will not exceed two-times the projected value at 54 EFPY. The licensee concluded that its neutron surveillance program meets the requirements specified in 10 CFR Part 50, Appendix H, and that this program adequately monitors neutron-induced embrittlement in low alloy steel RV base metals and their associated welds.

The staff reviewed the licensee's RV surveillance program under SPU conditions and finds it acceptable. This acceptance is based on:

(1) The neutron fluence value obtained from the latest surveillance capsule exceeds the projected neutron fluence value for the license renewal period (54 EFPY) under the SPU conditions. However, this value is less than two-times the projected 32 EFPY vessel fluence, and therefore, it complies with the requirement specified in paragraph 7.6.2 of the ASTM E185. Hence, the implementation of SPU does not affect the surveillance capsule withdrawal schedule.

(2) Consistent with the requirements of paragraph 7.6.2 of the ASTM E185, the licensee stated that the next capsule (stand by capsule Z) will be withdrawn when the projected neutron fluence value will not exceed two-times the projected value at 54 EFPY.

(3) The licensee's surveillance capsule program complies with the requirements specified in 10 CFR Part 50, Appendix H and 10 CFR 50.60.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the RV surveillance withdrawal schedule and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the schedule. The NRC staff further concludes that the RV capsule withdrawal schedule is appropriate to ensure that the material surveillance program will continue to meet the requirements of 10 CFR, Part 50, Appendix H, and 10 CFR 50.60, and will provide the licensee with information to ensure continued compliance with GDC-14 and GDC-31 in this respect following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the RV material surveillance program.

2.1.2 Pressure-Temperature Limits and Upper-Shelf Energy (USE)

Regulatory Evaluation

Pressure-temperature (P-T) limits are established to ensure the structural integrity of the ferritic components of the RCPB during any condition of normal operation, including anticipated operational occurrences (AOOs) and hydrostatic tests. The NRC staff's review of P-T limits covered the P-T limits methodology and the calculations for the number of EFPYs specified for the proposed SPU, considering neutron embrittlement effects and using linear elastic fracture mechanics. The NRC's acceptance criteria for P-T limits are based on: (1) GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (2) GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; (3) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB; and (4) 10 CFR 50.60, which requires compliance with the requirements of 10 CFR Part 50, Appendix G. Specific review criteria are contained in SRP Section 5.3.2 and other guidance provided in Matrix 1 of RS-001.

Technical Evaluation

2.1.2.1 USE Value Calculations

The NRC staff's criteria for maintaining acceptable levels of USE for the RV beltline materials of operating reactors throughout the licensed lives of the facilities is provided in 10 CFR Part 50, Appendix G. The rule requires RV beltline materials to have a minimum USE value of 75 ft-lb in the unirradiated condition, and to maintain a minimum USE value above 50 ft-lb throughout the licensed period of operation of the facility, unless it can be demonstrated through analysis that lower values of USE would provide acceptable margins of safety against fracture equivalent to those required by Appendix G of Section XI of the American Society of Mechanical Engineers *Boiler and Pressure Vessel Code* (ASME Code). The rule also mandates that the methods used to calculate USE values must account for the effects of neutron irradiation on the USE values for the materials and must incorporate any relevant RV surveillance capsule data that are reported through implementation of a plant's 10 CFR Part 50, Appendix H RV material surveillance program.

The licensee discussed the impact of the approximate 7 percent SPU on the USE values for the RV beltline materials in Section 2.1.2 of the Attachment 5 of the DNC's SPU LR, dated July 13, 2007. In this section, the applicant stated that all RV beltline materials have a USE greater than 50 ft-lb through the EOL, 54 EFPY, as required by Appendix G to 10 CFR Part 50. Table 2.1.2-4 of the SPU LR provides the predicted USE values for MPS3 beltline materials, based on the neutron fluence value equivalent to 54 EFPY. In NUREG-1838, "Safety Evaluation (SE) Report Related to the License Renewal of the Millstone Units 2 and 3,"[8] the staff, reviewed and approved the use of a neutron fluence value for 54 EFPY, which exceeds the neutron fluence value under SPU conditions at 54 EFPY for the limiting beltline material as shown in Table 2.1.2-4 of the SPU LR. In request for additional information (RAI) CVIB-07-002, dated October 29, 2007,[9] the staff requested that the licensee explain why the neutron fluence value at 54 EFPY under SPU conditions is lower than the staff-approved value as shown in the NUREG-1838. In its response to RAI CVIB-07-002, dated November 19, 2007,[10] the licensee stated that the projected neutron fluence value approved by the staff in NUREG-1838 was based on the analysis of MPS3 surveillance capsule X. The projected neutron fluence value under SPU conditions at 54 EFPY was obtained from the analysis of the more recent MPS3 surveillance capsule W, which projected a lower value under SPU conditions at 54 EFPY. The methodology used to project the neutron fluence values for surveillance capsules X (WCAP-15405[11]) and W (WCAP-16629[12]) adhered to the guidance in Regulatory Guide (RG) 1.190, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence,"[13] or its precursor Draft RG, DG-1053, "Calculational and Dosimetry Methods for Determining Pressure Vessel Nuetron Fluence."[14]

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[8] ADAMS Accession No. ML053270483
[9] ADAMS Accession No. ML072960179
[10] ADAMS Accession No. ML073230976
[11] WCAP-15405NP, "Analysis of Capsule X from the Northeast Nuclear Energy Company Millstone Unit 3 Reactor Vessel Radiation Surveillance Program" Westinghouse Electric Company, LLC by E. Terek at al, May, 2000.
[12] WCAP-16629NP, "Analysis of Capsule W from the Dominion Nuclear Connecticut Millstone Unit 3 Reactor Vessel Radiation Surveillance Program" Westinghouse Electric Company, LLC by F.C. Gift at al, September, 2006.
[13] ADAMS Accession No. ML010890301
[14] ADAMS Accession No. ML003777844

The projected peak neutron fluence values on the inside surface of the RV for 32 and 54 EFPYs are 1.97 x 10^{19} n/cm^2 (E > 1 MeV) and 3.31 x 10^{19} n/cm^2 (E > 1 MeV), respectively. In addition, the calculation assumed that the equilibrium cycle 15 core loading will be implemented through the 54 EFPYs. The equilibrium cycle retains the low leakage features of the core. MPS3 has three additional surveillance capsules remaining. Removal and analysis of additional surveillance capsules will indicate whether the predicted fluence values are on target or need adjustment.

The staff performed an independent calculation of the EOL USE values for the MPS3 RV beltline materials using the limiting 54 EFPY neutron fluence value for the one-quarter of the RV wall thickness (1/4T) location for the SPU conditions. Consistent with its evaluation of USE addressed in the NUREG-1838, the staff determined that the Lower Shell Plate 9802-2 (D1242-2) is the limiting beltline material for USE evaluation. The licensee applied Regulatory Position 1.2 of the RG 1.99, Revision 2, "Radiation Embrittlement of Reactor Vessel Materials,"[15] to calculate the USE value at 54 EFPY for this material. The staff also used Regulatory Position 1.2 of the RG 1.99, Revision 2, and obtained the same USE value at 54 EFPY for this material. Since the USE value of the limiting beltline material calculated by the staff and the licensee is greater than the minimum USE value of 50 ft-lbs required by 10 CFR Part 50, Appendix G, the staff concludes that the beltline materials in the MPS3's RV will have acceptable USE values under the SPU conditions.

2.1.2.2 P-T Limit Calculations

Section IV.A.2 of 10 CFR Part 50, Appendix G requires that the P-T limits for operating reactors be at least as conservative as those that would be generated if the methods of calculation in the ASME Code, Section XI, Appendix G were used to calculate the P-T limits. The rule also requires that the P-T limit calculations account for the effects of neutron irradiation on the RV beltline materials and to incorporate any relevant RV surveillance capsule data that are required to be reported as part of the licensee's implementation of its 10 CFR Part 50, Appendix H RV materials surveillance program.

Heatup and cooldown limit curves have been calculated using the adjusted RT_{NDT} corresponding to the limiting beltline material of the reactor pressure vessel for the current period of licensed operation, which is 32 EFPY. In accordance with 10 CFR 50, Appendix G, updated P-T limits for the period of extended operation of 54 EFPY will be developed and implemented prior to the period of extended operation.

As indicated in the staff's SE dated August 27, 2001,[16] MPS3's current P-T limits are valid for 32 EFPY, and these P-T limits were developed using a higher projected neutron fluence predicted for SPU conditions. Therefore, the licensee contends that, because it used more conservative values, the current P-T limits are still valid for the current SPU conditions. In RAI CVIB-07-002, dated August 27, 2007,[17] the staff requested that the licensee explain why the neutron fluence value at 32 EFPY with SPU is lower than the one that was used for developing the current P-T curves for 32 EFPY. In its response to RAI CVIB-07-002, in a letter dated November 19,

[15] ADAMS Accession No. ML003740284
[16] ADAMS Accession No. ML012060343
[17] ADAMS Accession No. ML072390305

2007,[18] the licensee stated that the neutron fluence value for 32 EFPY under SPU conditions was obtained from the analyses of the latest surveillance capsule (W). This value is less than the value that was used for the current P-T limits which was derived from the analyses of the previous capsule (X). The staff agrees with the licensee's statement that the current P-T limits that were developed using a more conservative neutron fluence value are valid for the current term (32 EFPY) under SPU conditions. Therefore, the staff's concern related to RAI CVIB-07-002 is resolved.

2.1.2.3 Fracture Integrity Evaluation

Fracture toughness requirements for ferritic materials (low alloy steel or carbon steel) materials in the RCPB components which include the RV, pressurizer and steam generators (SGs) are provided in 10 CFR Part 50, Appendix G. Also identified in 10 CFR Part 50, Appendix G is the requirement that RCPB materials must satisfy the criteria in Appendix G of Section XI of the ASME Code to ensure the structural integrity of the ferritic components of the RCPB during any condition of normal operation, including AOOs and hydrostatic tests.

In RAI-CVIB-07-001, dated October 29, 2007,[19] the staff requested that the licensee confirm that the proposed SPU for the MPS3 does not affect the bounding fracture toughness analyses for the RV materials. The licensee was requested to confirm that these analyses are still valid for the pressurizer and the SGs at MPS3. In response to the RAI-CVIB-07-001, the licensee, in a letter dated November 19, 2007,[20] stated that the current fracture toughness requirements for the RCPB components other than RV comply with the requirements of 10 CFR Part 50, Appendix G. In addition, the licensee stated that implementation of the SPU does not affect the current fracture toughness analyses for the RCPB components other than the RV. Since the fracture toughness analyses for the RCPB components, other than the RV, comply with 10 CFR Part 50, Appendix G, and since the implementation of SPU does not affect the fracture toughness analyses of these components, the staff concludes that the current analyses for the RV material are bounding and that these analyses are still valid under SPU conditions for all the ferritic RCPB materials. Therefore, the staff concludes that its concern related to RAI-CVIB-07-001 is resolved.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the P-T limits for the plant and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the P-T limits. The NRC staff further concludes that the licensee has demonstrated the validity of the proposed P-T limits for operation under the proposed SPU conditions. Based on this, the NRC staff concludes that the proposed P-T limits will continue to meet the requirements of 10 CFR Part 50, Appendix G, and 10 CFR 50.60 and will enable the licensee to comply with GDC-14 and GDC-31 in this respect following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the proposed P-T limits.

[18] ADAMS Accession No. ML073230976
[19] ADAMS Accession No. ML072960179
[20] ADAMS Accession No. ML073230976

2.1.3 Pressurized Thermal Shock

Regulatory Evaluation

The pressurized thermal shock (PTS) evaluation provides a means for assessing the susceptibility of the RV beltline materials to PTS events to assure that adequate fracture toughness is provided for supporting reactor operation. The NRC staff's review covered the PTS methodology and the calculations for the reference temperature, RT_{PTS}, at the expiration of the license, considering neutron embrittlement effects. The NRC's acceptance criteria for PTS are based on: (1) GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture; (2) GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (3) 10 CFR 50.61, insofar as it sets fracture toughness criteria for protection against PTS events. Specific review criteria are contained in SRP Section 5.3.2 and other guidance provided in Matrix 1 of RS-001.

Technical Evaluation

The staff has established requirements in 10 CFR 50.61 that are designed to protect the RVs of PWRs against the consequences of PTS events. The rule requires licensees owning PWR-designed light-water reactors to calculate a nil-ductility reference temperature at EOL neutron fluence (RT_{PTS} as defined in 10 CFR 50.61) for each base metal and weld material in the RV made from carbon or low-alloy steel materials. The rule also requires the RT_{PTS} values to be maintained below the PTS screening criteria throughout the serviceable life of the facilities. The rule sets a maximum limit of 270°F for RT_{PTS} values that are calculated for base metals (i.e., forging and plate materials) and axial weld materials and a maximum limit of 300°F for RT_{PTS} values that are calculated for circumferential weld materials.

A required methodology for calculating these RT_{PTS} values, are provided in 10 CFR 50.61, which are based on the calculation methods in RG 1.99, Revision 2. For materials in the beltline region of the RV, the rule requires that the calculations account for the effects of neutron irradiation on the materials and incorporate any relevant RV surveillance capsule data that are required to be reported as part of the licensee's implementation of its RV material surveillance program.

The licensee discussed the impact of the SPU on the MPS3 PTS assessment in Section 2.1.3 of the Attachment 5 of the DNC's SPU LR, dated July 13, 2007.[21] The licensee stated that the PTS assessment for the MPS3 RV under the uprated conditions is limited by the intermediate shell plate (Heat B9805-1). The limiting material is Intermediate Shell Plate B9805-1, with the more limiting RT_{PTS} value occurring for calculations using the RG 1.99, Rev. 2, Position 1.1 Chemistry Factor, as opposed to the Position 2.1 Chemistry Factor calculated from credible surveillance data. The staff performed an independent calculation of the EOL RT_{PTS} values for MPS3 using the 54 EFPY neutron fluence value for the clad-metal interface location of the vessel at SPU conditions. As stated in Section 2.1.2.1 of this SE, the neutron fluence value is acceptable because it was obtained from the latest credible surveillance capsule data. The staff

[21] ADAMS Accession No. ML072000386

used position 1.1 of the RG 1.99, Revision 2 for the chemistry factor for calculating the RT_{PTS} value for the limiting beltline material. Based on the review, the staff determined that the licensee's RT_{PTS} calculations comply with the requirements specified in 10 CFR 50.61. Both the RT_{PTS} values cited by the licensee and the staff are consistent and less than the rule's PTS screening criteria established for the limiting beltline material. The NRC staff, therefore, concludes that the beltline materials in the MPS3 RV meet the requirements of 10 CFR 50.61.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the PTS for the plant and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on PTS. The NRC staff further concludes that the licensee has demonstrated that the plant will continue to meet the requirements of GDC-14, GDC-31, and 10 CFR 50.61 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to PTS.

2.1.4 Reactor Internal and Core Support Materials

Regulatory Evaluation

The reactor internals and core supports include structures, systems, and components (SSCs) that perform safety functions or whose failure could affect safety functions performed by other SSCs. These safety functions include reactivity monitoring and control, core cooling, and fission product confinement (within both the fuel cladding and the RCS). The NRC staff's review covered the materials' specifications and mechanical properties, welds, weld controls, nondestructive examination procedures, corrosion resistance, and susceptibility to degradation. The NRC's acceptance criteria for reactor internal and core support materials are based on GDC-1 and 10 CFR 50.55a for material specifications, controls on welding, and inspection of reactor internals and core supports. Specific review criteria are contained in SRP Section 4.5.2, WCAP-14577,[22] and BAW-2248.[23]

Technical Evaluation

The licensee discussed the impact of the SPU on the structural integrity of the MPS3 reactor vessel internals (RVIs) and core supports in Section 2.1.4.2 of Attachment 5 to DNC's proposed SPU License Amendment Request, dated July 13, 2007.

In Section 2.1.4.2 of Attachment 5 to DNC's proposed SPU License Amendment Request, dated July 13, 2007, the licensee identified the effect of the SPU on the following aging mechanisms and provided its evaluation of these aging effects on the RVIs and core supports:

(1) Degradation of fuel cladding;

(2) Transgranular stress corrosion cracking (TGSCC), intergranular stress corrosion cracking (IGSCC) and primary water stress corrosion cracking (PWSCC) of RVIs;

[22] ADAMS Accession No. ML011080790

23 "Demonstration of the Management of Aging Effects for the Reactor Vessel Internals," Babcock & Wilcox Owners Group Report Number BAW-2248 (ADAMS Accession No. ML993490310)

(3) Radiation embrittlement and irradiation-assisted stress corrosion cracking (IASCC) of RVIs;

(4) Void swelling of RVIs; and

(5) Thermal aging of cast austenitic and precipitation-hardened stainless steels (SSs).

Degradation of Fuel Cladding

The licensee addressed the issue of fuel cladding corrosion due to implementation of SPU. Proper control of RCS water chemistry complying with the requirements specified in the Electric Power Research Institute (EPRI) report–EPRI TR-1002884, "Pressurized Water Reactor Primary Water Chemistry Guidelines,"[24] is essential to adequately manage fuel cladding corrosion. The licensee further stated that industry experience and available laboratory results suggest that when RCS water chemistry complies with these guidelines no discernable degradation due to fuel cladding corrosion occurs. The staff reviewed the licensee's evaluation and finds it acceptable because the licensee continues to comply with the EPRI guidelines that were established for controlling RCS water chemistry during the current period of operation and during the license renewal period. Additionally, a topical report TR6-54, "Review of Failed Fuel, 2000-2006," (proprietary version) developed by the Institute of Nuclear Power Operations confirms that fuel cladding corrosion can be minimized by proper control of the RCS water chemistry. Therefore, the staff concludes that the licensee adequately addressed the effect of the SPU on the fuel cladding corrosion at MPS3.

TGSCC/IGSCC/PWSCC

Historically, various forms of SCC generally occur in austenitic SSs and nickel-based alloys when they are exposed to the following conditions:

(1) Presence of oxygen and/or aggressive ions, i.e., chlorides and sulphates;

(2) Temperature greater than 200^0 F; and

(3) The presence of stress.

All the aforementioned variables need to be present to experience SCC and, therefore, in the absence of any one of these variables SCC is not likely to occur in the RVIs. The licensee claimed that by controlling water chemistry of the RCS per the EPRI-TR1002884 report, TGSCC and IGSCC will be adequately mitigated in the RVIs. The licensee further stated that the minimal increase in temperature under SPU conditions does not accentuate TGSCC or IGSCC. The staff reviewed the the licensee's evaluation of SCC in RVIs and compared the information with previous analysis in NUREG-1838.[25] The staff finds that the SPU is bounded by NUREG-

[24] ADAMS Accession No. ML081140288

[25] "Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, Docket Nos. 50-336 and 50-423, Dominion Nuclear Connecticut, Inc.," (ADAMS Accession No. ML053270483).

1838. Therefore, the staff finds the licensee's evaluation of SCC in RVIs under SPU conditions acceptable.

Radiation Embrittlement and IASCC of RVIs

Radiation embrittlement and IASCC occur when austenitic SSs and nickel-based alloys RVIs are exposed to a neutron fluence value greater than 1 X 10^{21} n/cm^2 (E > 0.1 MeV). In a typical PWR, RVIs (lower core barrel, baffle/former assembly, baffle/former bolts, lower core plate and fuel pins, lower support forging, and clevis bolts) are potentially prone to radiation embrittlement. The staff reviewed the the licensee's evaluation of radiation embrittlement and IASCC of RVIs and compared the information with previous analysis in NUREG-1838.[26] The staff finds that the SPU is bounded by NUREG-1838. Therefore, the staff finds the licensee's evaluation of radiation embrittlement and IASCC on RVIs under SPU conditions acceptable.

Void Swelling of the RVIs

Void swelling causes a general increase in the size of the component when it is exposed to neutron radiation. Industry experience thus far suggests that, in general, significant void swelling does occur in components that are exposed to neutron radiation during normal plant operating conditions. The licensee stated that PWR baffle bolts are known to experience a minor amount of void swelling which is not significant enough to affect their intended function during the plant's life. The staff finds that the SPU is bounded by NUREG-1838.[27] Therefore, the staff finds the licensee's evaluation of void swelling of the RVIs under SPU conditions acceptable.

Thermal Aging of Cast Austenitic and Precipitation-Hardened SSs

Cast austenitic stainless steels (CASS) when exposed to temperatures above 482^0 F experience thermal aging embrittlement which depends on the chemical composition of the material. There are two processes for CASS materials: (1) static and (2) centrifugal. CASS materials with the following attributes are more susceptible to thermal embrittlement:

(1) Greater Molybdenum content;

(2) Greater ferrite content;

(3) CASS manufactured by –casting process of static cast with low molybdenum content with ferrite greater than 20%.

Thermal embrittlement occurs in static cast low molybdenum content (< 0.5%) CASS with ferrite content greater than 20%; whereas, centrifugal cast stainless steels and static cast low molybdenum stainless steels with ferrite content less than or equal to 20% ferrite are not potentially susceptible to thermal embrittlement. According to the licensee, the CASS RVIs in MPS3 contain low (0.5% maximum) molybdenum content with a maximum ferrite content of

[26] "Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, Docket Nos. 50-336 and 50-423, Dominion Nuclear Connecticut, Inc.," (ADAMS Accession No. ML053270483).
[27] "Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3, Docket Nos. 50-336 and 50-423, Dominion Nuclear Connecticut, Inc.," (ADAMS Accession No. ML053270483).

20%. Therefore, they are not subject to thermal emrittlement under normal operating conditions and, as such, implementation of the SPU will not affect this aging degradation, based on the engineering judgement of the staff.

In 2001, one Babcock and Wilcox (B&W) licensee experienced failures of two CRDM 17-4 PH (precipitation-hardened) lead screw male couplings. The failures were attributed to thermal embrittlement of the 17-4 PH martensitic SS materials. The staff issued NRC Information Notice (IN) 2007-02, "Failure of Control Rod Drive Mechanism Lead Screw Male Coupling at a Babcock and Wilcox Designed Facility,"[28] in which the staff reiterated the importance of implementing frequent visual and surface examinations for identifying defects which may lead to the failure of thermally embrittled 17-4 PH martensitic SS RVIs.

In RAI CVIB-07-003, dated October 29, 2007,[29] the staff requested that the licensee provide the following information with respect to monitoring the aging degradation of any 17-4 PH martensitic SS materials used in RVIs at MPS3:

(1) Identify 17-4 PH martensitic SS RVIs at MPS3; and

(2) Identify the method of inspection that was performed thus far on these components, and provide information regarding any aging degradation that was identified thus far in these components.

In response to the RAI CVIB-07-003, the licensee, in a letter dated November 19, 2007,[30] stated that there are no 17-4 PH materials in RVIs at the MPS3. The staff finds this response acceptable and as such concludes that its concern related to RAI CVIB-07-003 is resolved.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the susceptibility of reactor internal and core support materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in operating temperature and neutron fluence on the integrity of reactor internal and core support materials. The NRC staff further concludes that the licensee has demonstrated that the reactor internal and core support materials will continue to be acceptable and will continue to meet the requirements of GDC-1 and 10 CFR 50.55a following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to reactor internal and core support materials.

[28] ADAMS Accession No. ML070100459
[29] ADAMS Accession No. ML072960179
[30] ADAMS Accession No. ML073230976

2.1.5 Reactor Coolant Pressure Boundary Materials

Regulatory Evaluation

The RCPB defines the boundary of systems and components containing the high-pressure fluids produced in the reactor. The NRC staff's review of RCPB materials covered their specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs. The NRC's acceptance criteria for RCPB materials are based on: (1) 10 CFR 50.55a and GDC-1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (3) GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; (4) GDC-31, insofar as it requires that the RCPB be designed with margin sufficient to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (5) 10 CFR Part 50, Appendix G, which specifies fracture toughness requirements for ferritic components of the RCPB. Specific review criteria are contained in SRP Section 5.2.3 and other guidance provided in Matrix 1 of RS-001. Additional review guidance for primary water stress-corrosion cracking (PWSCC) of dissimilar metal welds and associated inspection programs is contained in Generic Letter (GL) 97-01,[31] Information Notice (IN) 00-17,[32] Bulletin (BL) 01-01,[33] BL 02-01,[34] and BL 02-02.[35] Additional review guidance for thermal embrittlement of CASS components is contained in a letter from C. Grimes (Branch Chief in the License Renewal and Standardization Branch of the Division of Regulatory Improvement Programs in the Office of Nuclear Reactor Regulation of the NRC) to D. Walters (Director of Emergency Planning and Security in the Nuclear Generation Division of the Nuclear Energy Institute (NEI)), dated May 19, 2000.[36]

Technical Evaluation

The licensee indicated that the RCPB defines the boundary of systems and components containing the high-pressure fluid that transfers the heat generated in the reactor. The MPS3 evaluation of the RCPB materials covered their specifications, compatibility with the reactor coolant, fabrication and processing, susceptibility to degradation, and degradation management programs.

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[31] Generic Letter 97-01, "Degradation of CRDM/CEDM Nozzle and Other Vessel Closure Head Penetrations," dated April 1, 1997.(NUDOCS No. 973260336)

[32] NRC Information Notice 2000-17: "Crack in Weld Area of Reactor Coolant System Hot Leg Piping at V. C. Summer," dated October 18, 2000 (ADAMS Accession No. ML003760993)

[33] NRC Bulletin 2001-01: "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles," dated August 3, 2001 (ADAMS Accession No. ML012080284)

[34] NRC Bulletin 2002-01: "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity," dated March 18, 2002 (ADAMS Accession No. ML020770497)

[35] NRC Bulletin 2002-02: "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs," dated August 9, 2002 (ADAMS Accession No. ML022200494)

[36] ADAMS Accession No. ML003717179

Austenitic Stainless Steels

The two degradation mechanisms that are applicable to austenitic stainless steels in the reactor coolant environment are intergranular stress corrosion cracking (IGSCC) and transgranular stress corrosion cracking (TGSCC). Sensitized microstructure, susceptible materials, and the presence of oxygen are required for the occurrence of IGSCC, while the introduction of halogens such as chlorides and the presence of oxygen are prerequisites for the occurrence of TGSCC. The chemistry changes resulting from uprating do not involve introduction of any of these contributors so that no effect on material degradation is expected in the RCPB stainless steel components as a result of the power uprate.

The licensee stated that the proposed Lithium (Li), Boron (B), and pH management program meets EPRI chemistry guidelines under "PWR Primary Water Chemistry Guidelines: Vol.1, Rev. 5, TR-1002884."[37] Since these guidelines are specifically designed to prevent fuel cladding corrosion effects, specifically fuel deposit build-up, there will be no adverse effect on fuel cladding corrosion as a result of the proposed power uprate. Experience with operating plants as well as with the guidelines provide by EPRI suggest that increasing initial Li concentrations 3.5 parts per million (ppm) with controlled boron concentrations to maintain pH values ranging from 6.9 to 7.4 has not produced any undesirable fuel cladding integrity issues. MPS3 plans to maintain Li levels at 3.5 ppm or less.

The chemistry changes for the SPU do not involve the introduction of any of the contributors for SCC of austenitic stainless steel. Therefore, the NRC staff finds that there is reasonable assurance that there will be no significant increase in material degradation due the stretch power uprate for austenitic stainless steels used in the RCPB.

Alloy 600/82/182 Components

The licensee stated that Alloy 600 and Alloy 82/182 weld deposits are present in the MPS3 RCS. The most significant factor that influences the PWSCC of Alloy 600/82/182 components is the service temperature. The most significant Alloy 600/82/182 components that are bounding to the PWSCC susceptibility are the hot leg nozzles. The applicant estimates that the maximum increase in the hot leg temperature will be 4.3ºF due to the SPU.

The licensee estimated that the temperature increase will reduce the remaining lifetime before PWSCC initiation. The licensee estimates this reduction to be 18 percent for nozzles that will experience hot leg temperatures. The bottom mounted instrument nozzles in the RV bottom head and the CRDM nozzles in the RV closure head at MPS3 experience temperatures that are approximately at the RV inlet (cold-leg) temperature. The licensee determined that the SPU will increase the cold-leg temperature by 0.5ºF. This 0.5ºF increase may reduce the remaining PWSCC lifetime of these nozzles by 2 percent.

In a January 10, 2008,[38] letter, the licensee detailed actions being taken to address PWSCC susceptibility and any increases due to the power uprate. The licensee's most recent volumetric inspections of the hot leg nozzles detected no cracking. Currently, the licensee is required to

[37] ADAMS Accession No. ML032370054
[38] ADAMS Accession No. ML080100611

inspect these locations once every 10 years, in accordance with ASME Code. MRP-139[39] guidance suggests that hot leg locations with no cracking be volumetrically inspected every 5 years and cold leg locations every 6 years unless mitigative actions are taken. In the January 10, 2008, letter, the licensee discusses the impracticality of bare metal visual exams of the hot and cold leg weldments. MPS3 plans to perform a flaw growth and tolerance analysis on a plant-specific basis to show that the MRP-139 volumetric inspection interval is adequate for managing potential PWSCC of the RPV nozzle weld locations so that the bare metal visual examinations are not necessary. This alternative and evaluation is a matter of MRP-139 compliance under current operating conditions, and is needed irrespective of the proposed power uprate. The NRC staff's conclusions here are based on the small temperature change which will not require changes to the current examinations program. Any changes to the MRP-139 examination requirements will need to be resolved with the NRC. Should the NRC require examinations based on ASME Code or other regulations, the licensee will need to comply with those requirements or again resolve any deviations with the NRC. The licensee also states that MPS3 will inspect the CRDM nozzles in accordance with Revision 1 of NRC Order EA-03-009[40] or the ASME Code when it is changed to incorporate CRDM nozzle inspection requirements.

In addition, MPS3 has an on-going program to mitigate piping welds subject to PWSCC. The pressurizer welds have already been mitigated. At this time the licensee is evaluating technologies and schedules to mitigate the hot and cold leg nozzles. Mitigation plans for the RPV nozzles will be updated when demonstrated mitigation techniques become available.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the susceptibility of RCPB materials to known degradation mechanisms and concludes that the licensee has identified appropriate degradation management programs to address the effects of changes in system operating temperature on the integrity of RCPB materials. The NRC staff further concludes that the licensee has demonstrated that the RCPB materials will continue to be acceptable following implementation of the proposed SPU and will continue to meet the requirements of GDC-1, GDC-4, GDC-14, GDC-31, 10 CFR Part 50, Appendix G, and 10 CFR 50.55a. Therefore, the NRC staff finds the proposed SPU acceptable with respect to RCPB materials.

2.1.6 Leak-Before-Break

Regulatory Evaluation

Leak-before-break (LBB) analyses provide a means for eliminating from the design basis the dynamic effects of postulated pipe ruptures for a piping system. NRC approval of LBB for a plant permits the licensee to: (1) remove protective hardware along the piping system (e.g., pipe whip restraints and jet impingement barriers); and (2) redesign pipe-connected components, their supports, and their internals. The NRC staff's review for LBB covered: (1) direct pipe failure mechanisms (e.g., water hammer, creep damage, erosion, corrosion, fatigue, and environmental conditions); (2) indirect pipe failure mechanisms (e.g., seismic

[39] "Materials Reliability Program: Primary System Piping Butt Weld Inspection and Evaluation Guideline" (MRP-139NP), dated July 14, 2005 (ADAMS Accession No. ML052150196)
[40] ADAMS Accession No. ML041950390

events, system overpressurizations, fires, flooding, missiles, and failures of SSCs in close proximity to the piping); and (3) deterministic fracture mechanics and leak detection methods. The NRC's acceptance criteria for LBB are based on GDC-4, insofar as it allows for exclusion of dynamic effects of postulated pipe ruptures from the design basis. Specific review criteria are contained in draft SRP Section 3.6.3 and other guidance provided in Matrix 1 of RS-001.

Technical Evaluation

In Section 2.1.6 of the submittal, the licensee stated that the current structural design basis includes the application of LBB methodology to eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS loop piping as specified in GDC 4. The licensee's submittal describes the analyses and evaluations performed to demonstrate that the elimination of the analysis of dynamic effects of large breaks continues to be justified at the operating conditions associated with MPS3 SPU conditions.

The LBB analyses for MPS3 are documented in topical report WCAP-10587, dated June 1984.[41] These analyses were also evaluated during the plant license renewal for continued acceptability. NUREG-1838[42] contains the NRC evaluation related to the LBB analyses for license renewal.

To support the MPS3 power uprate, the licensee evaluated the LBB analyses to determine if they remain valid following implementation of the proposed power uprate conditions. The primary loop piping dead weight, normal thermal expansion, safe-shutdown earthquake (SSE), pressure loads, and normal operating temperature and pressure under power uprate conditions were used in the evaluation. The recommendations and criteria included in SRP 3.6.3 were used in the evaluation. The evaluation showed that all LBB recommended margins were satisfied for the power uprate conditions.

The LBB acceptance criteria and the recommended margins stated in SRP 3.6.3 are as follows:

- Margin of 10 on leak rate;
- Margin of 2 on flaw size; and
- Margin of 1 on loads (using faulted load combinations by the absolute summation method)

The evaluation results demonstrate the following: (1) a margin of 10 exists between the calculated leak rate from the leakage flaw and the leak detection capability of 1 gallon-per-minute (gpm); (2) a margin of 2 or more exists between the critical flaw size and the flaw size having a leak rate of 10 gpm (the leakage flaw); and (3) a margin of 1 on load exists using faulted load combinations by the absolute summation method. The evaluation results showed that the LBB conclusions of the current LBB analyses for MPS3 remain valid and unchanged for the SPU conditions.

[41] NUDOCS No. 8409250371
[42] ADAMS Accession No. ML053270483

The licensee's evaluation that the LBB acceptance criteria are satisfied for the MPS3 primary loop piping under power uprate conditions were found to be acceptable by the NRC staff. All the recommended margins are satisfied and the conclusions in the current LBB analyses remain valid. Therefore, the licensee's evaluation that the dynamic effects of the RCS primary loop pipe breaks need not be considered in the structural design basis of MPS3 at the power uprate conditions was found to be acceptable by the NRC staff.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the LBB analysis for the plant and concludes that the licensee has adequately addressed changes in primary system pressure and temperature and their effects on the LBB analyses. The NRC staff further concludes that the licensee has demonstrated that the LBB analyses will continue to be valid following implementation of the proposed SPU and that lines for which the licensee credits LBB will continue to meet the requirements of GDC-4. Therefore, the NRC staff finds the proposed SPU acceptable with respect to LBB.

2.1.7 Protective Coating Systems (Paints) - Organic Materials

Regulatory Evaluation

Protective coating systems (paints) provide a means for protecting the surfaces of facilities and equipment from corrosion and contamination from radionuclides and also provide wear protection during plant operation and maintenance activities. The NRC staff's review covered protective coating systems used inside the containment for their suitability for and stability under design-basis loss-of-coolant accident (DBLOCA) conditions, considering radiation and chemical effects. The NRC's acceptance criteria for protective coating systems are based on: (1) 10 CFR Part 50, Appendix B, which states quality assurance requirements for the design, fabrication, and construction of safety-related SSCs; and (2) Regulatory Guide 1.54, Revision 1, for guidance on application and performance monitoring of coatings in nuclear power plants. Specific review criteria are contained in SRP Section 6.1.2.

Technical Evaluation

MPS3 has protective coating systems inside the primary containment. These coating systems are safety related and are designated as Service Level I, because their failure could adversely affect the operation of post-accident fluid systems including the ECCS. In a letter dated November 12, 1998,[43] MPS3 provided a description of their coatings program as part of their response to Generic Letter (GL) 98-04, "Potential for degradation of the Emergency Core Cooling System and the Containment Spray System After a Loss-Of Coolant Accident."[44] Service Level I coatings at MPS3 are subject to the requirements of American National Standards Institute (ANSI) standards ANSI N101.2, "Protective Coatings (Paints) for Light Water Nuclear Reactor Containment Facilities," and ANSI N101.4-1972, "Quality Assurance for Protective Coatings Applied to Nuclear Facilities." In addition, the MPS3 Protective Coatings and Linings Program ensures that RG 1.54 quality assurance program recommendations are followed for protective coating work with the exception of miscellaneous equipment such as

[43] NUDOCS No. 9811200121
[44] NUDOCS No. 9807010291

valve bodies, handwheels, electrical cabinetry and control panels, loudspeakers, hangers and snubbers, and emergency light cases.

This relatively small quantity of coatings is considered unqualified and is appropriately evaluated for potential impact on ECCS performance.

Qualification of coating systems at MPS3 is based on physical testing of specific coatings on the substrate to which they are applied. Coating materials essentially identical to those used in containment were subjected to simulated DBLOCA environment conditions including pressure and temperature transients, radiation dose, and chemical exposure. The MPS3 SPU application compared the actual test conditions to the postulated DBLOCA conditions both before and after the proposed power uprate.

Under current operating conditions, the calculated post-LOCA peak containment pressure is 38.40 pounds per square inch gauge (psig). The post-LOCA peak containment pressure under SPU conditions is 41.33 psig. Qualification testing subjected the coatings to pressure transients with a peak pressure of at least 67 psi. The peak pressure under SPU conditions is bounded by the previously performed qualification testing.

Under current operating conditions, the calculated post-LOCA peak containment temperature is 261.99 °F. The post-LOCA peak containment temperature under SPU conditions is 267 °F. Qualification testing subjected the coatings to temperature transients with a peak temperature of at least 300 °F. The peak temperature under SPU conditions is bounded by the previously performed qualification testing.

Under current operating conditions, the calculated post-LOCA integrated radiation dose (40 year normal plus accident) in the containment is 2.4 E +08 RADS. The post-LOCA integrated radiation dose under SPU conditions (60 year normal pus accident) in the containment is 2.5 E+08 RADS. Qualification testing subjected the coatings to a radiation dose of at least 4 E+08 RADS. The total integrated radiation dose under SPU conditions is bounded by the previously performed qualification testing.

The qualified coatings inside containment are qualified for a minimum pH of 5.0 and a maximum pH of 10.5. Under SPU conditions, the pH will start at 4.1 and will remain below 5.0 for approximately 10 minutes at the onset of the DBLOCA because of the analyzed bounding boron concentration in the safety injection accumulators. The licensee performed analysis to show that the coatings could withstand a pH of 4 for as long as 2 hours without an adverse impact on the material. The NRC staff determined that based on the short duration of exposure to fluid with a pH below 5.0 the post-LOCA sump pH under SPU conditions will not have an adverse affect on the qualified protective coatings.

Coating condition assessment is performed during each RFO in accordance with MPS3 Engineering Procedure, “Inspection and Condition Assessment of Coating Material on Components Within the Containment.” This procedure calls for a general walk down of the containment and a visual inspection of all readily accessible areas in containment. The NRC staff agrees that the coating condition assessment methodology used at MPS3 is consistent with the intent of RG 1.54 and the standards that it endorses, and is therefore acceptable.

Other organic materials used inside containment including polyester varnish on motor electrical insulation, silicon foam to seal penetrations, hydraulic oil, lubricating oil, cable insulation, and charcoal filters were selected for use because they have adequate resistance to the normal operating environment as well as the DBLOCA environment. As previously described for protective coatings, the DBLOCA temperature, pressure, radiation, and chemistry are not significantly different under the proposed SPU conditions than the currently postulated DBLOCA conditions. The NRC staff finds that the other organic materials in containment will remain acceptable under SPU conditions based on their current environmental resistance and the relatively small impact that the SPU has on environmental conditions both during normal operation and under DBLOCA conditions.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on protective coating systems and concludes that the licensee has appropriately addressed the impact of changes in conditions following a DBLOCA and their effects on the protective coatings. The NRC staff further concludes that the licensee has demonstrated that the protective coatings will continue to be acceptable following implementation of the proposed SPU and will continue to meet the requirements of 10 CFR Part 50, Appendix B. Therefore, the NRC staff finds the proposed SPU acceptable with respect to protective coatings systems.

2.1.8 Flow-Accelerated Corrosion

Regulatory Evaluation

Flow-accelerated corrosion (FAC) is a corrosion mechanism occurring in carbon steel components exposed to flowing single- or two-phase water. Components made from stainless steel are immune to FAC, and FAC is significantly reduced in components containing small amounts of chromium or molybdenum. The rates of material loss due to FAC depend on velocity of flow, fluid temperature, steam quality, oxygen content, and pH. During plant operation, control of these parameters is limited and the optimum conditions for minimizing FAC effects, in most cases, cannot be achieved. Loss of material by FAC will, therefore, occur. The NRC staff has reviewed the effects of the proposed SPU on FAC and the adequacy of the licensee's FAC program to predict the rate of loss so that repair or replacement of damaged components could be made before they reach critical thickness. The licensee's FAC program is based on Bulletin 87-01, "Thinning Pipe Walls in Nuclear Power Planrs,"[45] GL 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning,"[46] and the guidelines in EPRI Report NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program."[47]
It consists of predicting loss of material using the CHECWORKS computer code, and visual inspection and volumetric examination of the affected components. The NRC's acceptance criteria are based on the structural evaluation of the minimum acceptable wall thickness for the components undergoing degradation by FAC.

[45] NUDOCS No. 8707020018
[46] NUDOCS No. 8905040276
[47] ADAMS Accession No. ML070580416

Technical Evaluation

The MPS3 FAC program is based upon NRC BL 87-01, "Thinning Pipe Walls in Nuclear Power Plants,"[48] Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," and the guidelines in EPRI Report NSAC-202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program."[49] The CHECWORKS computer code, in conjunction with visual inspection and volumetric examination, is used to support analysis for predicting loss of material.

The proposed SPU will result in changes to several process variables that may directly influence component wear rates due to FAC. To account for these changes the licensee updated the affected parameters in the CHECWORKS predictive model based on the expected power uprate heat balance. In a January 11, 2008, letter responding to questions from the NRC staff, the licensee provided tabulated data for a sample of over 30 different components. This data included the current values and the predicted changes resulting from SPU for temperature, flow rate, quality, and wear rate for each component listed. The comparison of pre-SPU and post-SPU wear rate predictions showed changes ranging from slight decreases in wear to as high as an approximate 32 percent increase. The licensee provided further discussion of the tabulated results, explaining that, in addition to the wear rate for a given component, MPS3 considers the absolute current wear rate, the actual component thickness, and the design margin when evaluating the predictive data.

Also in the January 11, 2008, letter, the licensee responded to NRC staff questions about the ability of CHECWORKS to provide accurate predictions given the current lack of actual field data for MPS3 under SPU conditions. The licensee stated that the FAC program at MPS3 continually incorporates field data into CHECWORKS and monitors the actual wear rates and thicknesses against predicted wear. The continual updating of the CHECWORKS database is performed to ensure that the predictive model is informed based on the most current operating conditions and wear rates.

As part of the same January 11, 2008, letter, the licensee addressed NRC staff questions about particulate matter in the SG blow down system potentially causing material loss in excess of the values predicted by CHECWORKS. The licensee stated that component structural calculations that are based on ultrasonic examination (i.e., field data) are maintained for trending purposes. MPS3 uses both the field data and the CHECWORKS model. If a discrepancy is identified and the CHECWORKS model is unable to accurately predict component life, for situations such as particle impingement, then the field data is used to direct future examination or component replacement as needed.

The licensee stated that for modifications required in support of the proposed SPU, impact on the FAC Program is evaluated as part of the plant design change process. For new components and any affected existing components, inclusion in the FAC Program will be considered based on the existing program criteria. Affected components will be subject to program requirements.

The MPS3 FAC Program was evaluated for continued acceptability for license renewal. NUREG-1838, "Safety Evaluation Report (SER) Related to the License Renewal of the Millstone

[48] NUDOCS No. 8707020018
[49] ADAMS Accession No. ML030580416

Power Station, Units 2 and 3," states that the FAC program is adequate to manage the aging effects for which it is credited, and is consistent with generic aging lessons learned. The requirements, methods, and criteria of the existing FAC Program will continue to be implemented following the proposed SPU. The licensee evaluated the impact of the SPU on the system parameters affecting FAC and concluded that the SPU does not affect the conclusions of NUREG-1838, and that there are no new aging effects requiring management. The NRC staff has reviewed the licensee's evaluation of SPU impact on system parameters and the FAC Program and determined that there is no impact on the conclusions drawn in the previously performed license renewal review.

Conclusions

The NRC staff has reviewed the licensee's evaluation on the effect of the proposed SPU on the FAC analysis for the plant and concludes that the licensee has adequately addressed changes in the plant operating conditions in the FAC analysis. The NRC staff further concludes that the licensee has demonstrated that the updated analyses will predict the loss of material by FAC and will ensure timely repair or replacement of degraded components following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to FAC.

2.1.9 Steam Generator Tube Inservice Inspection

Regulatory Evaluation

Steam generator (SG) tubes constitute a large part of the reactor coolant pressure boundary (RCPB). The staff reviewed the effects of changes in operating parameters (e.g., pressure, temperature, and flow velocities) resulting from the proposed power uprate on the design and operation of the SGs. Specifically, the staff evaluated whether changes to these parameters continue to be bounded by those considered in the plant design and licensing basis (i.e., the technical specification plugging limits). Acceptance criteria for SG tube inservice inspection (ISI) are based upon Regulatory Guide 1.121, "Bases for Plugging Degraded PWR Steam Generator Tubes,"[50] Regulatory Guide 1.83, "Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes,"[51] and Standard Review Plan Sections 5.4.2.1, "Steam Generator Materials," and 5.4.2.2, "Steam Generator Tube Inservice Inspection."

Technical Evaluation

MPS3 has four Westinghouse model F SGs. Each SG contains 5,626 thermally treated Alloy 600 tubes. The tubes have an outside diameter of 0.688 inches and a nominal wall thickness of 0.040 inches. The tubes are hydraulically expanded for the full depth of the tubesheet at each end. The tubes are supported by stainless steel support plates with quatrefoil-shaped holes and V-shaped chrome plated Alloy 600 anti-vibration bars (AVB).

Potential degradation mechanisms for MPS3 SG tubes include: (1) wear at AVBs; (2) wear at the flow distribution baffle; (3) wear from foreign objects; (4) pitting at secondary side sludge deposits; (5) outside diameter stress corrosion cracking (ODSCC); (6) outside diameter

[50] ADAMS Accession No. ML003739366
[51] ADAMS Accession No. ML003740256

intergranular attack (ODIGA); and primary water stress corrosion cracking (PWSCC). The proposed SPU will cause potential changes in temperature, flow rate, and SG chemistry which may influence the tube degradation mechanisms listed above. Corrosion mechanisms such as PWSCC, ODSCC, and pitting are influenced by an increase in operating temperature. Mechanical processes such as AVB wear and foreign object wear are more dependant on changes in tube bundle flow rates. The NRC staff finds the licensee's evaluation that no significant impact on the tube degradation mechanisms is expected based on the parameter changes resulting from the proposed SPU acceptable.

The NRC staff finds the licensee's evaluation of the design and operational functions of the SGs and the conclusion that the SGs will continue to satisfy all design and operational functions under power uprate conditions acceptable. The NRC staff finds the licensee's evaluation that they have identified appropriate degradation management inspections to address the effects of temperature, differential pressure, and flow rates on SG tube integrity acceptable.

The NRC staff reviewed the licensee's evaluation that SG tube integrity will continue to be maintained and will continue to meet the performance criteria in NEI 97-06, "Steam Generator Program Guidelines,"[52] and the requirements of 10 CFR 50.55a following implementation of the proposed SPU.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on SG tube integrity and concludes that the licensee has adequately assessed the continued acceptability of the plant's TSs under the proposed SPU conditions and has identified appropriate degradation management inspections to address the effects of changes in temperature, differential pressure, and flow rates on SG tube integrity. The NRC staff further concludes that the licensee has demonstrated that SG tube integrity will continue to be maintained and will continue to meet the performance criteria in NEI 97-06, "Steam Generator Program Guidelines,"[53] and the requirements of 10 CFR 50.55a following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to SG tube ISI.

2.1.10 Steam Generator Blowdown System

Regulatory Evaluation

Control of secondary-side water chemistry is important for preventing degradation of SG tubes. The SG blowdown system (SGBS) provides a means for removing SG secondary-side impurities and thus, assists in maintaining acceptable secondary-side water chemistry in the SGs. The design basis of the SGBS includes consideration of expected and design flows for all MODES of operation. The NRC staff's review covered the ability of the SGBS to remove particulate and dissolved impurities from the SG secondary side during normal operation, including AOOs (main condenser inleakage and primary-to-secondary leakage). The NRC's acceptance criteria for the SGBS are based on GDC-14, insofar as it requires that the RCPB be

[52] ADAMS Accession No. ML010430054
[53] ADAMS Accession No. ML010430054

designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture. Specific review criteria are contained in SRP Section 10.4.8.

Technical Evaluation

The SGBS is designed to control the chemical composition of the SG shell side, allow for diversion of blowdown liquid to the radioactive liquid waste system in the event of a SG tube leak, provide for containment isolation of blowdown lines, and to reduce the quantities of solids that accumulate as a result of the boiling process. The SGBS is designed to allow for continuous blowdown by equal flow from each of the four SGs or with an equivalent total flow through a single SG.

The SGBS blowdown flow rates will increase by approximately 7 percent for both the single SG blowdown and the blowdown through all SGs simultaneously as a result of SPU. The SGBS piping and valves were evaluated to ensure that this increase in flow rate is acceptable for implementation. The flow control valves will need to be repositioned to control the blowdown flow. The control valves will be 30 percent open for the lower flow rate from distributed flow through all SGs and approximately 70 percent open for blowdown through 1 SG. The flow control valves and level controllers have adequate margin to control the flow at SPU conditions. In addition the containment isolation design function will be maintained since the blowdown flow rates and pressures do not exceed existing valve design capabilities. The SGBS will continue to be monitored by the FAC program.

The predicted operating pressures and temperatures in the SGs, SG blowdown tank, and interconnecting piping and valves will decrease slightly under SPU conditions. The SG design parameters are therefore bounded for the predicted SPU conditions.

Under SPU conditions, the MPS3 SGBS will continue to maintain secondary side water chemistry within industry guidelines to provide an environment suitable for maintenance of controlled corrosion rates in secondary system carbon steel components.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the SGBS and concludes that the licensee has adequately addressed changes in system flow and impurity levels and their effects on the SGBS. The NRC staff further concludes that the licensee has demonstrated that the SGBS will continue to be acceptable and will continue to meet the requirements of GDC-14 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to SGBS.

2.1.11 Chemical and Volume Control System

Regulatory Evaluation

The chemical and volume control system (CVCS) and boron recovery system (BRS) provide means for: (a) maintaining water inventory and quality in the RCS; (b) supplying seal-water flow to the reactor coolant pumps and pressurizer auxiliary spray; (c) controlling the boron neutron absorber concentration in the reactor coolant; (d) controlling the primary water chemistry and reducing coolant radioactivity level; and (e) supplying recycled coolant for demineralized water

makeup for normal operation and high-pressure injection flow to the ECCS in the event of postulated accidents. The NRC staff reviewed the safety-related functional performance characteristics of CVCS components. The NRC's acceptance criteria are based on: (1) GDC-14, insofar as it requires that the RCPB be designed so as to have an extremely low probability of abnormal leakage, of rapidly propagating fracture, and of gross rupture; and (2) GDC-29, insofar as it requires that the reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in event of anticipate operational occurrences. Specific review criteria are contained in SRP Section 9.3.4.

Technical Evaluation

The primary function of the CVCS is to maintain RCS water inventory, boron concentration, and water chemistry. In addition, the CVCS provides for boric acid addition and removal, chemical additions for corrosion control, reactor coolant cleanup and degasification, reactor coolant makeup, and processing of reactor coolant letdown.

The increase in core power and RCS temperature affect the CVCS requirements related to core reload boron and the heat charging flow. The licensee evaluated the RCS fluid interfaces with CVCS including the regenerative, letdown, seal water, and excess letdown heat exchangers. The design and operating conditions of the heat exchangers were reviewed to confirm that the SPU conditions remain bounded by the current heat exchanger design and operating conditions. The maximum required boron concentrations are expected to increase slightly and remain within the capability of the CVCS and BRS.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed SPU on the CVCS and BRS and concludes that the licensee has adequately addressed changes in the temperature of the reactor coolant and their effects on the CVCS and BRS. The NRC staff further concludes that the licensee has demonstrated that the CVCS and BRS will continue to be acceptable and will continue to meet the requirements of GDC-14 and GDC-29 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the CVCS.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

Regulatory Evaluation

SSCs important to safety could be impacted by the pipe-whip dynamic effects of a pipe rupture. The NRC staff conducted a review of pipe rupture analyses to ensure that SSCs important to safety are adequately protected from the effects of pipe ruptures. The NRC staff's review covered: (1) the implementation of criteria for defining pipe break and crack locations and configurations; (2) the implementation of criteria dealing with special features, such as augmented ISI programs or the use of special protective devices such as pipe-whip restraints; (3) pipe-whip dynamic analyses and results, including the jet thrust and impingement forcing functions and pipe-whip dynamic effects; and (4) the design adequacy of supports for SSCs provided to ensure that the intended design functions of the SSCs will not be impaired to an unacceptable level as a result of pipe-whip or jet impingement loadings. The NRC staff's review focused on the effects that the proposed SPU may have on items (1) thru (4) above. The NRC's acceptance criteria are based on GDC-4, which requires SSCs important to safety to be designed to accommodate the dynamic effects of a postulated pipe rupture. Specific review criteria are contained in SRP Section 3.6.2.

Technical Evaluation

The current licensing basis for MPS3 pipe rupture analysis is in accordance with SRP Section 3.6.2. The MPS3 current structural design basis includes postulated ruptures in high energy and moderate energy piping in accordance with Branch Technical Position (BTP) MEB 3-1 of SRP Section 3.6.2. Consideration was also taken to provide design features that protect essential equipment from the dynamic effects of postulated pipe breaks both inside and outside containment (OC). The following exemptions to SRP 3.6.2 were taken as presented in UFSAR Section 1.9.

- SRP Section 3.6.2, Subsection III.2.a: MPS3 uses internal pressure and temperature conditions in the piping system during reactor operation at 100 percent power instead of pressure and temperature values corresponding to the greater contained energy at HOT STANDBY or at 102 percent power.

- SRP Section 3.6.2, Subsection III.2.a: MPS3 uses an allowable of 80 percent of energy absorbing capacity based on static testing instead of limiting the allowable capacity for crushable material to 80 percent of its rated energy absorbing capacity as determined by dynamic testing.

- BTP MEB 3-1, Section B.1.e: MPS3 does not postulate cracks in high energy piping.

The current structural design basis of MPS3 implements the guidance of GDC-4 to include the application of LBB methodology and eliminate consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping. In response to the NRC staff's RAI, the licensee reaffirmed that the basis for using LBB methodology is still valid under the proposed stretch power uprate (SPU) conditions. The staff's evaluation of LBB is documented in Section 2.1.6 of this SE.

Postulated pipe breaks inside and OC for applicable piping systems, as described in UFSAR Sections 3.6.1 and 3.6.2, were evaluated by the licensee to address revised SPU operating conditions. In its response to staff RAI, the licensee confirmed that the analyses included the reactor coolant loop (RCL) branch line pipe breaks (BLPBs) and performed dynamic analyses, as necessary, to account for the dynamic effects associated with BLPBs. RCL BLPBs considered in the application included the RHR pump suction lines off of the loop A and loop D hot legs; the pressurizer surge line off of the loop B hot leg; and the safety injection line off of Loops A, B, C and D. The licensee's analyses also included main steam and feedwater line breaks (FLB). The licensee also confirmed that the applicable load combinations were used in accordance with the existing MPS3 licensing and design basis including UFSAR Sections 3.6.1 and 3.6.2 that conforms to BTP ASB 3-1 and MEB 3-1.

Pipe rupture locations and dynamic effects are within the scope of license renewal. Hence, the licensee also evaluated the SPU impact on the conclusions reached in the MPS3 License Renewal Safety Evaluation Report NUREG-1838 for pipe break, jet impingement and pipe whip considerations and found that the SPU conditions do not add any new components nor do they introduce any new functions for existing components that would change the license renewal system evaluation boundaries.

Using methods, criteria and load combinations from the existing design basis analyses of record, the licensee concluded that the SPU evaluations performed for applicable piping systems did not result in any new or revised break/crack locations, and the design basis for pipe break, jet impingement, pipe whip and environmental considerations remain valid for SPU. The staff finds the licensee's analysis methodology associated with the break locations and the associated dynamic effects of pipe breaks to be adequate and acceptable based on SRP Section 3.6.2.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to determinations of rupture locations and associated dynamic effects and concludes that the licensee has adequately addressed the effects of the proposed SPU on them. The NRC staff further concludes that the licensee has demonstrated that SSCs important to safety will continue to meet the requirements of GDC-4 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the determination of rupture locations and dynamic effects associated with the postulated rupture of piping.

2.2.2 Pressure-Retaining Components and Component Supports

Regulatory Evaluation

The NRC staff has reviewed the structural integrity of pressure-retaining components (and their supports) designed in accordance with the ASME Code, Section III, Division 1, and GDCs 1, 2, 4, 14, and 15. The NRC staff's review focused on the effects of the proposed SPU on the design input parameters and the design-basis loads and load combinations for normal operating, upset, emergency, and faulted conditions. The NRC staff's review covered: (1) the analyses of flow-induced vibration (FIV); and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and cumulative fatigue usage factors (CUFs) against the code-allowable limits. The NRC's acceptance criteria are based on: (1) 10 CFR 50.55a and GDC 1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (4) GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (5) GDC 15, insofar as it requires that the RCS be designed with margin sufficient to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 5.2.1.1 and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

Nuclear Steam Supply System Piping, Components, and Supports

The Nuclear Steam Supply System (NSSS) piping, which is the RCS piping, consists of four heat transfer piping loops (loops A, B, C and D) connected in parallel to the RPV. The licensee's SPU LR indicates that MSP3's current design bases for NSSS piping, components and supports meet the requirements of 10 CFR 50.55(a)(1), and GDC 1, 2, 4, 14 and 15, as documented in MSP3's UFSAR Sections 3.1, 3.2, 3.7N, 3.9N and 5.4. In addition, the MSP3's NSSS piping, components, and supports were evaluated for the continued acceptability to support plant license renewal. NUREG-1838 SER for MPS3's license renewal, dated August 1, 2005, documents the results of that review. The NSSS piping and support systems were evaluated to the ASME Code, Section III, Code Class 1, 1971 Edition and Addenda through summer 1973. The NSSS piping stress and support evaluations that the licensee performed included evaluations of primary equipment supports for the SGs, RC pumps, Pressurizer, and the RV. The results of the piping evaluations concluded that NSSS piping systems remain acceptable and will continue to satisfy design basis requirements when considering the operational effects resulting from SPU conditions. The results of the equipment nozzle evaluations also concluded that these components remain within acceptable limits for SPU conditions.

The licensee evaluated the existing design basis analyses for RCL piping and associated branch piping, RCL primary equipment supports and pressurizer surge line to assess the effect on components associated with the implementation of SPU. Specifically, the following items were evaluated by the licensee and, where necessary, reanalyzed with SPU parameters:

- RCL LOCA analysis using Loop LOCA hydraulic forces and the associated Loop LOCA RPV motions for the SPU program;
- RCL piping stresses;
- RCL displacements at branch piping connections to assess the impact on the branch piping analyses;
- Pressurizer surge line piping analysis including the effects of thermal stratification; and
- RCL primary equipment support and nozzle loads (RV, SG, Reactor Coolant Pump, and Pressurizer)

Because it is acceptable to the NRC to assume that leaks will develop and be detected before any break, breaks are not postulated for the RCL hot leg, cold leg and crossover leg piping (See Section 2.1.6, LBB). As part of the RCL and associated branch piping and support evaluations for the SPU program, the licensee reconciled the loop LOCA hydraulic forcing function forces and associated loop LOCA RPV motions from applicable RCL branch line breaks. In its response (dated January 14, 2008) to a NRC staff RAI, the licensee stated that the RCL branch line breaks that were considered included the RHR pump suction lines off of the Loop A and Loop D hot legs; the pressurizer surge line off of the Loop B hot leg; and the safety injection lines off of Loops A, B, C and D. Dynamic forcing functions were developed for these seven branch line breaks and included consideration of broken loop and unbroken loop applications. In its response to staff RAI, the licensee also stated that the dynamic forcing functions were used as input into a piping structural model. Piping stresses, pipe support loads and primary equipment support loads were developed and reconciled to existing design basis criteria. SPU LR Table 2.2.2.1-1 provides a summary of current stress and CUFs, revised stress and CUFs values for SPU conditions, and the resulting design margins for each piping analysis that required detailed evaluation to reconcile SPU conditions. Piping systems not specifically listed in Table 2.2.2.1-1 did not require detailed evaluation to reconcile SPU conditions. The reported results have incorporated the RCL LOCA hydraulic forcing functions and associated loop LOCA reactor pressure vessel motions, as applicable, that were reconciled as part of the SPU evaluations.

In its response (dated January 14, 2008) to a NRC staff RAI, the licensee stated that all locations in Table 2.2.2.1-1 where the CUF exceeds 0.1 are postulated pipe break locations. These locations are postulated pipe break locations in the current design basis. There are no new locations as a result of SPU where the CUF exceeds 0.1. Also, the “SPU” column in Table 2.2.2.1-1 represents CUFs based upon a 60-year plant life. In the “Current” column of Table 2.2.2.1-1, CUF values come from pre-license renewal engineering analyses (i.e., 40-year plant life). The tabulated results (Table 2.2.2.1-1) of calculated stress and CUF values are below the code allowable limits and are, therefore, acceptable.

On the basis of its review of the licensee's submittal and response to a NRC staff RAI, the staff agrees with the licensee's conclusion that the structural integrity of the NSSS piping and supports, the primary equipment nozzles, and the primary equipment supports will continue to meet the MPS3 current licensing basis with respect to the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14 and GDC-15 for the proposed SPU.

Balance-of-Plant Piping, Components, and Supports

The licensee evaluated the effects of the proposed SPU implementation on the balance-of-plant (BOP) and Non-Class 1 piping and supports inside and OC and considered the plant life extension to 60 years documented in NUREG-1838 SER for MPS3's license renewal, dated August 1, 2005. Section 2.2.2.1 of this SER covered Class 1 RCL and safety injection piping and supports up to the Class 1 boundary. The licensee's SPU LR indicates that MSP3's current design bases for BOP piping, components and supports meet the requirements of 10 CFR 50.55(a)(1), and GDC 1, 2, 4, 14 and 15, as documented in MSP3's UFSAR Sections 3.2, 3.7 and 3.9B. The licensee evaluated BOP piping and support systems to assess the impact of operating temperature, pressure and flow rate changes that will result from the implementation of SPU in accordance with the criteria of ASME Code, Section III Code Class 2 and 3, 1971 Edition and Addenda through summer 1973 and ANSI B31.1 – 1973 Code for Pressure Piping through summer 1973 Addenda, as described in UFSAR Sections 3.7 and 3.9. Included in the licensee's evaluations are the following BOP piping and support systems: main steam; feedwater; condensate; feedwater heater vents and drains; moisture separator vents and drains; extraction steam; circulating water; component cooling water; auxiliary feedwater (AFW); spent fuel pool (SFP) cooling; service water; SG blowdown; radwaste systems; safety injection (BOP); CVCS; RHR; quench spray; and recirculation spray.

In evaluating pipe stress levels and pipe support and equipment loads at SPU conditions, the licensee established "change factors" by dividing SPU parameters of temperature, pressure and flow rate by current analyzed operating data of temperature, pressure and flow rate obtained from heat balance diagrams and calculations. For change factors less than or equal to 1.00 where the current condition envelopes or equals the SPU condition, the piping and support system was concluded to be acceptable for SPU conditions. In its response, dated January 14, 2008,[54] to a NRC staff RAI, the licensee indicated that for piping systems containing "change factors" greater than 1.00 (portions of the feedwater, condensate, feedwater heater vents and drains, moisture separator vents and drains, containment recirculation and CCW piping) detailed assessments were performed using simplified hand calculation methods (increasing existing stresses and loads) or by performing more detailed computer analyses to demonstrate piping and pipe support component acceptability. A summary of the maximum stress levels for current and SPU conditions including a comparison to code of record allowable stress levels is provided in Table 2.2.2.2-1. For each piping system listed in this table, the stresses reported are at the most critical locations of the piping system, corresponding to the piping location containing the highest stress ratio (SPU stress divided by the allowable stress). These critical stress locations may be at equipment nozzles, containment penetrations, or any in-line piping component (e.g., valve, elbow, or reducer) within the analytical boundaries of the piping stress model. The revised stress levels at SPU conditions are shown to be within code of record allowable stress levels and are, therefore, acceptable. In its response to the NRC staff's RAI, the licensee provided a summary which demonstrates that for SPU conditions loads and/or

[54] ADAMS Accession No. ML080140570

stresses for nozzles and containment penetrations that were most affected by SPU are also within design basis allowable values and acceptable. Therefore, the licensee concluded that no piping modifications (physical piping re-routes) are required due to SPU. In its response to the NRC staff's RAI, the licensee also provided details of modifications for approximately 21 existing pipe supports, in systems with "change factors" greater than 1.00, required to meet design basis allowable values. The modifications ranged from building up and adding welds, replacing pipe support members/components (e.g., struts and snubber assemblies, pipe clamps or threaded rods) and stiffening existing members. In addition, four new supports (two spring hangers, one strut and one rigid support) were required to be added due to SPU loads on the feedwater system (FWS) piping located in the turbine building. The licensee also stated that support modifications required for SPU will be completed prior to increasing the reactor core power above 3411 MWt (current license condition). Reactor core power operation above 3411 MW is scheduled to occur after the fall 2008 RFO. The NRC staff finds the licensee's response acceptable as it has demonstrated that BOP piping and pipe supports, after completing necessary modifications, will satisfy code of record and design basis requirements.

In its response to the NRC staff's RAI, in regard to thermal expansion on the issue that piping could potentially expand due to higher SPU temperature in affected systems and impose an unanalyzed condition that could potentially overstress piping and supports or otherwise damage SSCs, the licensee said that during the baseline walkdown performed for piping vibration, piping systems that would be subject to a temperature increase associated with SPU were inspected to identify if there was a potential for unacceptable thermal expansion interaction. None were noted. In addition, the licensee stated that during startup with the SPU, piping systems will be observed to identify any unanticipated unacceptable conditions. The NRC staff finds the licensee's response acceptable, as the licensee has properly addressed the issue that piping thermal expansion at higher SPU temperature will not impose an unanalyzed condition that could potentially overstress piping and supports or otherwise damage SSCs.

In its response dated January 14, 2008, the licensee indicated that a comprehensive plan has been developed to address FIV in piping affected by the MPS3 power uprate. The plan began with the development of a program to address scope, method, evaluation and acceptance criteria. The scope includes all piping with increased flow rates resulting from the power uprate (including main steam, extraction steam, feedwater, condensate, feedwater heater vents and drains and moisture separator vents and drains. The method entails performing a series of walkdowns spanning from the current plant condition to the completion of power ascension testing following implementation of the power uprate. The baseline walkdowns were performed on October 22-23, 2007. Those walkdowns for the current plant condition identified no current adverse conditions. The licensee stated that in order to validate that the piping systems will remain acceptable at SPU conditions, approximately 50 locations were identified where detailed observations will be performed during power uprate implementation. In its response dated January 14, 2008, the licensee indicated that per the power ascension test procedure, baseline data for piping vibrations at the current full power (3411 MWt) will be collected prior to shutdown for the fall 2008 RFO. After this RFO, power will increase to the new proposed power level of 3650 MWt. In response to the NRC staff's RAI, the licensee also indicated that piping systems which will experience increased flow rates due to SPU will be inspected using visual methods during SPU implementation. Initially simple tools and methods as described in ASME Operations & Maintenance (O&M) Code, Part 3 will be used. If warranted, hand-held instrumentation will be employed to record data. The licensee confirmed that the piping vibration plan for MPS3 SPU is in accordance with ASME O&M Code, Part 3. The NRC staff

finds the licensee's plan to monitor piping FIV adequate and acceptable as the licensee has verified that the methodology for evaluation and acceptance criteria for all piping evaluated for anticipated vibration will be in accordance with ASME O&M Code, Part 3.

Based on the NRC staff's review of MPS3's evaluations of BOP piping, components and supports for SPU as summarized above, the staff finds the licensee's methodology acceptable as it confirms with the code of record and plant design basis requirements and concurs with the licensee's conclusion that the BOP piping, components and supports, including planned support modifications and additions, will maintain their structural integrity for SPU conditions.

Reactor Vessel and Supports

The reactor pressure vessel (RPV) is the principal component of the RCS and contains the heat-generating core, core support structures, control rods, and other components directly associated with the core. The RPV primary outlet and inlet nozzles provide for the exit of heated coolant and its return to the RPV for recirculation through the core. The MPS3 RPV is cylindrical, with a welded hemispherical bottom head and a removable, flanged and gasketed, hemispherical upper head. MPS3 UFSAR Section 5 contains the current licensing and design basis for the RPV and its supports. The RPV and its supports are designed to withstand stresses originating from various operating design transients described in UFSAR Section 3.9N.1.1 and UFSAR Table 5.4-18. The RPV is designated safety class 1, as stated in UFSAR Section 5.3.1. Design and fabrication of the RPV was carried out in accordance with the ASME Code, Section III, Class 1 requirements. The RPV supports are designed to meet the same safety class designation as the components they support. The RPV supports are classified as QA Category 1 and Seismic Category I, as stated in UFSAR Table 3.2-1.

The licensee performed its evaluations for the MPS3 RPV at SPU conditions in accordance with the current plant code of record, ASME Code, Section III, Division 1, 1971 Edition through summer 1973 addenda. The analyses and evaluations performed incorporate the revised loads into the original RV stress report, due to SPU conditions. In evaluating the RPV and its supports, the licensee also considered the plant life extension to 60 years documented in NUREG-1838 SER for MPS3's license renewal, dated August 1, 2005.

The licensee states in the SPU LR that analysis of FIV for the RV and supports is not included in the licensing basis for MPS3. The fact that the mechanical design flow (MDF) for the SPU conditions continues to be unchanged at 103,000 gpm, as stated in the SPU LR, and the heavy RV component construction support the licensee's statement that the RV components are considered unaffected by SPU conditions.

The licensee, in its evaluations for the RPV components, assumed that the MPS3 RV components are essentially identical to those for the Seabrook Unit 1 and used Seabrook Unit 1 as a baseline. By employing this assumption, the licensee applied certain evaluations to MPS3 performed for Seabrook (referred to herein as "baseline")[55] The temperature and pressure transient information for the MPS3 SPU were reviewed by the licensee and found, in all cases, to be bounded by either the existing qualification, or by the similar uprate qualification of the baseline. The stress intensities (SIs) for those transients that were deemed more severe than

[55] Seabrook Station, Unit No. 1- Issuance of Amendment re: 5.2 Percent Power Uprate, TAC No. MC2364, February 28, 2005. (ADAMS Accession No. ML050140453)

their baseline counterparts were examined to determine their effect on the maximum ranges of SI for all the regions of the RV. The staff finds this assumption acceptable because the licensee stated that it has validated its assumption by detailed comparison of the drawings for the two units.

Revised maximum SI ranges and cumulative fatigue usage factors (CUF) were calculated and compared to the acceptance criteria of the current Code of Record ASME, Section III, Class 1 requirements. SPU LR Table 2.2.2.3-1 provides a summary of the maximum ranges of SI and maximum CUFs from the RV evaluation. All of the regions of the RV are shown to meet the primary plus secondary SI allowable of $3S_m$ (3 times the design stress intensity value) as specified by ASME Section III, NB-3222.2 with the exception of the bottom head instrument tubes "location 1" which exceeded the 3Sm limit and was noted that it was qualified by the elastic-plastic analysis, as allowed by NB-3228.3. In its response dated January 14, 2008, the licensee provided a summary of the results of the simplified elastic-plastic evaluation which shows that the special rules for exceeding $3S_m$ as provided by (a) through (f) of Subparagraph NB-3228.3 have been met. The NRC staff finds the licensee's stress and CUF RV evaluation and results acceptable as they were conducted in accordance with the plant licensing basis and met the code of record criteria requirements.

The licensee also reviewed the seismic and LOCA RV-to-internals interface loads for the SPU conditions and compared these loads with the allowable defined loads as part of the RV evaluation. All of the loads were found to be bounded by existing MPS3 analyses, and no additional load evaluation was required. SPU LR Table 2.2.2.3-2 contains a summary of the vessel-to-internals interface loads evaluation and Table 2.2.2.3-3 contains the RV CRDM housing interface loads. All the loads due to SPU are less than the allowable or limiting loads.

With respect to the RV supports, the loads used in the existing design basis calculations that perform the qualification and demonstrate the acceptability of the RV nozzle loads and the RV support loads are bounding loads that envelope loads associated with and resulting from SPU. Therefore, the RV nozzle loads and the RV support reaction loads are not impacted by the SPU.

On the basis of its review, as summarized above, the NRC staff agrees with the licensee's conclusion that the current design of MPS3's RPV and supports for SPU remains in compliance with 10 CFR 50.55a; GDC-1, 2, 4, 14 and 15, and the Code of Record ASME Section III Division 1.

Control Rod Drive Mechanism

The control rod drive mechanisms (CRDMs) are located on the dome of the RPV head and are coupled to rod cluster control assemblies (RCCAs). The primary function of the CRDMs is to insert, withdraw or hold stationary, RCCAs within the core to control average core temperature and to shutdown the reactor. The current MPS3's CRDMs are the originally-supplied Westinghouse Model L-106A CRDMs.

The licensee evaluated the structural integrity of the pressure retaining sections of the CRDM assembly under SPU conditions and its impact on renewed plant operating license evaluations and license renewal. The pressure vessel component of the CRDM assembly is part of the RCPB. It contains the latch housing and the rod travel housing which are connected by a threaded, seal welded maintenance joint. The closure at the top of the rod travel housing is a

threaded cap with a canopy seal weld for pressure integrity. The latch housing is the lower portion of the CRDM pressure vessel and encloses the latch assembly.

The CRDMs are designed in accordance with ASME Section III, Class 1 requirements (UFSAR Section 3.9F.4.2). The Code of Record for Model L-106A CRDMs is the ASME B&PV Code, Section III, Division 1, 1974 Edition through summer 1974 Addenda. The licensee used this Code of Record to evaluate the structural adequacy of the CRDM pressure vessel and its components for SPU conditions. The licensee reviewed generic and plant specific analyses in evaluating the CRDMs for SPU. Applicable loadings (which include pressure, deadweight, seismic, thermal and transient loads) and combinations are shown in UFSAR Table 3.9N-2. Pressure (RCPB), deadweight and seismic loads are unaffected by the SPU. Hot leg temperature (RPV outlet temperature) is 622.6 ^{O}F maximum for SPU and is bounded by the 650.0 ^{O}F used in the generic analysis for Model L-106A CRDMs. The licensee compared the SPU NSSS design transients against those used to analyze the generic Model L-106A CRDMs. The difference between the SPU transients and the generically analyzed transients is that two of the SPU transients, discussed in SPU LR Section 2.2.6, are not part of the existing design basis analysis. In addition, the licensee noted that there are temperature and pressure range differences between the SPU and existing design basis NSSS design transients. The licensee reconciled the differences between the SPU design transients and the design basis transients and recalculated SIs and CUF values to include SPU conditions using the current design basis methodology. In its response to an NRC staff RAI, the licensee resubmitted SPU LR Tables 2.2.2.4-1 through 2.2.2.4-3. These tables show current, SPU and code allowable SIs plus CUF values for the CRDM pressure vessel assembly and its components. All stress and CUF values meet the allowables defined by the criteria requirements of the design basis Code of Record for the MPS3 Model L-106A CRDMs. Maximum bending moments for the CRDM components for the faulted condition of seismic and LOCA are also within established allowable values with a minimum of 31 percent margin and are shown on Tables 2.2.2.4-5. The licensee also determined that since the CRDM RCPB is located on the RV Head, it experiences no flow induced vibration.

The licensee, using the current plant design basis methodology to evaluate the pressure boundary (PB) components of the CRDMs, has demonstrated that these components meet the Code of Record criteria requirements. Therefore, based on its review, as summarized above, the NRC staff concurs with the licensee that the MPS3 PB components of the CRDMs are structurally adequate for continuous operation under the proposed power uprate.

Steam Generators and Supports

The four SGs that MPS3 employs are Westinghouse Model F SGs. The current licensing and design basis for the SGs is contained in UFSAR Sections 3.9N, 5.1, 5.4.2 and Table 5.2-1. The current licensing and design basis for the SG supports is contained in UFSAR Sections 5.4.14.1.2, 5.4.14.2 and Table 5.4-18. The SGs were designed and fabricated in accordance with the requirements of ASME B&PV Code, Section III, Division 1, 1971 Edition through summer 1973 Addenda.[56] The Code of Record for the SG supports is the ASME Boiler and Pressure Vessel Code, Section III, Subsection NF 1974 Edition including 1974 winter Addenda.[57] The licensee used the Codes of Record to evaluate the structural adequacy of the

[56] UFSAR Table 5.2-1
[57] UFSAR Table 5.4-18

SGs PB and the internal components and SG supports for the new SPU conditions. In evaluating the SG and its supports, the licensee also considered the plant life extension to 60 years documented in NUREG-1838 SER for MPS3's license renewal, dated August 1, 2005. The licensee evaluated the SGs for SPU design parameters shown in SPU LR Tables 1-1 and 1-2 and for NSSS design transients discussed in SPU LR Section 2.2.6. The scope of the licensee's review included the SG PB, internal and external PB attachments and internal components. Formal evaluations were performed for the divider plate, tubesheet and shell junction, tube-to-tubesheet weld, tubes, feedwater nozzle, secondary manway bolts, steam nozzle, secondary-side wrapper support system components, blowdown pipe, and channel head and stub barrel digital metal impact monitoring system (DMIMS) holes. The current design basis was employed to demonstrate acceptability of PB and components attached to PB in accordance with the criteria of ASME B&PV Code Section III, Subsection NB. ASME Code, Section III, Subsections NB and NF were utilized as guidelines in evaluating the internal components, which are not part of the PB and are not governed by the ASME B&PV Code.

A summary of results of the licensee's evaluations showing SI and CUF values for both pre-SPU and SPU conditions is presented in SPU LR Tables 2.2.2.5.2.2-1 and 2.2.2.5.2.2-2. In response to the NRC staff's RAI, the licensee stated that only the critical internal components were analyzed. Critical internal components are those whose failure could violate the structural integrity of the tubes. Critical internal components not attached to the PB only need to be evaluated for the design condition which is not impacted by the SPU and, therefore, are not included in these tables. The tables include critical internals that are attached to the PB, as these are affected by the SPU. In Tables 2.2.2.5.2.2-1 and 2.2.2.5.2.2-2, at several locations where the primary plus secondary SI allowable limit of 3Sm (3 times the design stress intensity value), specified by ASME Code, Section III, NB-3222.2, was exceeded, the licensee noted that elastic-plastic analysis was performed to show acceptability. In its response to the NRC staff's RAI, the licensee provided a summary of the results of the elastic-plastic evaluation which shows that the special rules for exceeding 3Sm as provided by (a) through (f) of Subparagraph NB-3228.3 have been met. With respect to the feedwater ring, which is the most highly loaded of all the internals due to rapid feedwater flow and temperature changes, the licensee, in its response to the NRC staff's RAI, indicated that the feedwater ring evaluation met the ASME Code, Section III, Class 1 requirements. The licensee reported that at the two critical feedwater ring locations, at the J-nozzle weld and at the SG shell, the CUFs were 0.85 and 0.01 respectively, while the stress ratios (calculated/allowable) at all locations were less than 0.9. With the exception of the SG secondary side manway bolts, the licensee demonstrated that the SG PB, internal and external PB attachments and internal components (including SG tubes) meet the ASME Code, Section III, Class 1 requirements for SPU conditions including the plant life extension to 60 years. The secondary side manway bolts need to be replaced after 30 years of equivalent design cycles of actual operation at current power. The secondary manway bolts have been shown acceptable at SPU conditions for 30 years of equivalent design cycles. The staff finds the licensee's evaluation and results acceptable as it was performed in accordance with the plant design basis and met the Code of Record criteria requirements.

The licensee performed thermal-hydraulic analyses to evaluate the effects of tube wall local dryout (departure from nucleate boiling, which could result in excessive build-up of tube scale), hydrodynamic instability and moisture carryover. From the evaluations, the licensee determined that the thermal-hydraulic operating characteristics for the SPU are acceptable and there are no concerns of thermal performance deficiency, local dryout of tube walls, hydrodynamic instability or excessive moisture carryover.

The licensee evaluated the SG tubes for FIV and tube wear. Evaluations of FIV and tube wear were performed for fluid-elastic stability and amplitudes of tube vibration due to turbulences. In response to the NRC staff's RAI, the licensee indicated that the original analysis reported a fluid-elastic stability ratio of 0.5. It is conservatively predicted that the SPU will result in a 23 percent increase or a stability ratio of 0.62, which is still less than the allowable of 1.0. The licensee also indicated that the original 2 mils of turbulence induced displacements is predicted to increase by 49.6 percent at SPU resulting in approximately 3 mils of displacement. The licensee noted that this maximum displacement of 3 mils is less than the 146 mils needed to close the gap between tubes and cause wear. The licensee, in its response dated January 14, 2008, also indicated that the original tube FIV analysis resulted in approximately 200 psi maximum of tube bending stress. Using the maximum anticipated response from the most limiting SPU condition, it is predicted that the increased stress would be less than 300 psi, which is well below the endurance limit of the material.

With respect to the four feedwater rings, the licensee noted that the rings have experienced degradation from an ongoing erosion-corrosion process. Weld repairs have been performed in the past to maintain the structural integrity of the feedwater rings to perform their intended design function. As stated above, the licensee's feedwater ring evaluation met the ASME Code fatigue requirements with a maximum fatigue CUF of 0.85 at the J-nozzle weld. The licensee acknowledges that future weld repairs and/or partial or whole component replacement may become necessary to meet and maintain structural integrity of the feedwater rings for the higher flow rate at the proposed SPU operating conditions.

The licensee has also assessed the possibility of a J-nozzle separating from the feedwater ring and becoming a loose part due to erosion-corrosion and determined that the size of the J-nozzle and its attachment fillet weld would prevent it from traveling down the shell inside diameter (ID) and tube bundle wrapper outside diameter (OD) annulus and contacting a tube. Therefore, as the licensee stated, there is no potential for impact on tube integrity by a detached J-nozzle due to erosion-corrosion.

The licensee evaluated the SPU impact on the SG supports and noted that the SG support loads from the SPU RCS piping analyses remain bounded by the current design basis SG support loads. Therefore, the current design basis of the SG supports remains valid for the power uprate.

Using the current plant design basis methodology to evaluate the SGs and their supports, the licensee demonstrated that these components meet the code of record and design basis criteria requirements. Therefore, based on its review as summarized above, the staff concludes that the effects of SPU do not adversely affect the structural integrity of the SGs and their supports.

Reactor Coolant Pumps and Supports

The current licensing and design basis for the reactor coolant pump (RCP) is contained in UFSAR Sections 3.9N, 5.1, 5.4.1 and Table 5.2-1. The current licensing and design basis for the RCP supports is contained in UFSAR Sections 5.4.14.1.3, 5.4.14.2 and Table 5.4-18. The RCPs were designed and fabricated in accordance with the requirements of ASME B&PV Code, Section III, Division 1, 1974 Edition through winter 1974 Addenda.[58] The Code of Record for the

[58] UFSAR Table 5.2-1

RCP supports is the ASME Boiler and Pressure Vessel Code, Section III, Subsection NF 1974 Edition including 1974 summer Addenda.[59]

The licensee evaluated the RCS piping and supports (RPV supports, SG supports, RCP supports and the pressurizer supports) for SPU parameters and SPU NSSS design transients and considered the plant renewed license documented in NUREG-1838 SER for MPS3's license renewal, dated August 1, 2005. The NRC staff's review of the RCS piping and supports is presented in Section 2.2.2.2.1, NSSS piping, components, and supports, of this SER. Stretch power uprate parameters (such as temperature and pressure) with a comparison to the current power parameters are presented in SPU LR Table 1-1. The licensee compared the design loads developed from SPU conditions to those used in the existing design basis analyses of record and determined that the loads from the existing analyses bound the SPU design loads. The licensee also compared the recalculated SPU NSSS design transients, which are presented in SPU LR Section 2.2.6, to those used in the existing RCP analyses and noted that there are temperature and pressure range differences between the SPU and the existing analyses transients. The licensee recalculated CUFs for affected RCP components at SPU design transients. The staff reviewed the licensee's RCP component evaluation for SPU design transients, presented in SPU LR Section 2.2.2.6. Some of the CUFs increased while the stress ranges remained unaffected. Stretch power uprate CUFs are compared to the existing design basis analyses CUFs and presented in SPU LR Table 2.2.2.6-1. All of the CUF values are shown to be less than the allowable value (AV) of 1.0.

The licensee reviewed and compared the current design basis loadings on the RCP supports from the RCS piping due to deadweight, thermal expansion, seismic operating-basis earthquake (OBE), and seismic safe-shutdown earthquake (SSE) loading cases and determined that they are still valid for SPU because the current design basis loads envelop the loads due to the SPU conditions. Therefore, the current RCP support designs are not impacted by the SPU.

Using the current design basis and code of record, the licensee adequately addressed the SPU effects on the RCPs and supports. Based on its review as summarized above, the NRC staff concludes that the SPU does not adversely affect the structural integrity of the RCPs and their supports.

Pressurizer and Supports

The current licensing and design basis for the pressurizer is contained in UFSAR Sections 3.9N, 5.4.10 and Table 5.2-1. The current licensing and design basis for the pressurizer supports is contained in UFSAR Sections 5.4.14.1.4, 5.4.14.2 and Table 5.4-18. The pressurizer, surge line, and RCS piping are all designed in accordance with the requirements of ASME B&PV Code, Section III, 1971 Edition through summer 1973 Addenda. The Code of Record for the pressurizer supports is the ASME B&PV Code, Section III, Subsection NF 1974 Edition.

The licensee evaluated the pressurizer and its supports for SPU parameters summarized in SPU LR Section 1.1 and SPU NSSS design transients summarized in Section 2.2.6 and considered the plant life extension to 60 years documented in NUREG-1838 SER for MPS3's license renewal, dated August 1, 2005.

[59] UFSAR Table 5.4-18

The licensee reviewed and compared the design inputs used in the current pressurizer stress report to the revised inputs of the SPU and performed structural analyses and evaluations for cases where the revised inputs were not obviously bounded by the current inputs. Per the licensee's evaluation, design, emergency, faulted and test condition stresses remain unchanged. The maximum primary-plus-secondary stress intensity ranges for normal and upset conditions also remain unchanged. Because transient groupings and number of cycles for the revised SPU transients differ from those used in the current pressurizer stress report, the licensee recalculated the CUFs for SPU. Table 2.2.2.7.2-2 shows the ratio of the calculated primary-plus-secondary SIs to the allowable values at critical pressurizer locations. Table 2.2.2.7.2-1 shows a comparison of the calculated SPU CUFs at critical locations with those reported in the original stress reports. All CUFs shown in the summary of Table 2.2.2.7.2-1 are less than the AV of 1.0. In Table 2.2.2.7.2-2, at locations where the primary plus secondary SI allowable limit of 3Sm, specified by ASME Section III, NB-3222.2, was exceeded, the licensee has noted that elastic-plastic analysis was performed to show acceptability. In its response to the NRC staff's RAI, the licensee provided a summary of the results of the elastic-plastic evaluation which shows that the special rules for exceeding 3Sm, as provided by (a) through (f) of Subparagraph NB-3228.3 have been met. With respect to the pressurizer supports, the licensee indicated that they have been evaluated and found to be within design basis limits for SPU conditions.

The pressurizer surge line is monitored for thermal stratification. The generic evaluation of surge line stratification for the Westinghouse PWRs is included in WCAP-12639.[60] In a letter dated July 9, 1992,[61] the NRC indicated that the plant-specific surge line analysis, consistent with WCAP-12639, has demonstrated compliance with NRC BL 88-11.[62] The licensee revised the surge line thermal stratification pipe loads due to SPU and determined that the revised loads will have an insignificant impact on the surge line stratification design basis analysis. Therefore, the SPU has no significant impact in the surge line stratification.

The licensee also evaluated the SPU impact on the conclusions reached in the MPS3 license renewal SER for the pressurizer and its supports, and found that the NRC-approved aging evaluations in NUREG-1838 SER for the pressurizer and its supports remain valid for the SPU conditions.

Using the current plant design basis methodology and acceptance criteria, the licensee evaluated the structural integrity of the pressurizer and its supports under SPU conditions and determined their adequacy. Therefore, based on its review as summarized above, the staff agrees with the licensee that the MPS3 pressurizer and its supports are structurally adequate for continuous operation under the proposed power uprate.

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[60] NUDOCS No. 9104050237
[61] NUDOCS No. 9208040285
[62] NUDOCS No. 8812150118

Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of pressure-retaining components and their supports. For the reasons set forth above, the NRC staff concludes that the licensee has adequately addressed the effects of the proposed SPU on these components and their supports. Based on the above, the NRC staff further concludes that the licensee has demonstrated that pressure-retaining components and their supports will continue to meet the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, GDC-14, and GDC-15 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the structural integrity of the pressure-retaining components and their supports.

2.2.3 Reactor Pressure Vessel Internals and Core Supports

Regulatory Evaluation

Reactor pressure vessel internals consist of all the structural and mechanical elements inside the RV, including core support structures. The NRC staff reviewed the effects of the proposed SPU on the design input parameters and the design-basis loads and load combinations for the reactor internals for normal operation, upset, emergency, and faulted conditions. These include pressure differences and thermal effects for normal operation, transient pressure loads associated with LOCAs, and the identification of design transient occurrences. The NRC staff's review covered: (1) the analyses of FIV for safety-related and non-safety-related reactor internal components; and (2) the analytical methodologies, assumptions, ASME Code editions, and computer programs used for these analyses. The NRC staff's review also included a comparison of the resulting stresses and CUFs against the corresponding Code-allowable limits. The NRC's acceptance criteria are based on: (1) 10 CFR 50.55a and GDC-1, insofar as they require that SSCs important to safety be designed, fabricated, erected, constructed, tested, and inspected to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (3) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; and (4) GDC-10, insofar as it requires that the reactor core be designed with appropriate margin to assure that specified acceptable fuel design limits (SAFDLs) are not exceeded during any condition of normal operation, including the effects of AOOs. Specific review criteria are contained in SRP Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5; and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

The MPS3's evaluations of reactor pressure vessel (RPV) core support structures (CSS) and non-CSS (all internal structures that are not CSS) for the effects of the proposed power uprate are summarized in Section 2.2.3 of MPS3's SPU LR. The current licensing and design basis for the RPV internals is contained in UFSAR Sections 3.9N.5.3, 3.9N.2.3, 5.2.3.1, and Tables 3.2-1 and 5.2.3-3. UFSAR Table 3.2-1 states that reactor core supports and internals were designed to meet the intent of ASME Section III, Subsection NG, as they were designed and built prior to the implementation of Subsection NG. Therefore, as the licensee states, a plant-specific stress report on the reactor internals was not required. The MPS3 reactor internals were analyzed to

meet the intent of the ASME B&PV Code, Section III, 1971 Edition through summer 1973 Addenda.

Generic and plant-specific structural analysis evaluations have been performed for the RPV internals and meet the intent of the ASME Code. These analyses were used as the basis for evaluating critical MPS3 reactor internal components for SPU RCS conditions and revised NSSS design transients. The licensee performed specific evaluations at the SPU conditions for the following most limiting reactor internal components: upper core plate, lower support plate, lower core plate, lower support column, core barrel and baffle-former bolts. Summaries results of these evaluations for SPU conditions showing maximum stress intensity ranges and fatigue CUFs are presented in SPU LR Table 2.2.3-3. Where the primary plus secondary SI allowable limit of 3Sm, specified by ASME Section III, NB-3222.2, was exceeded, the licensee has stated that elastic-plastic analysis was performed to show acceptability. In its response dated April 4, 2008, the licensee provided a summary of the results of the elastic-plastic evaluation which shows that the special rules for exceeding 3Sm, as provided by (a) through (f) of Subparagraph NB-3228.3 have been met.

The licensee also evaluated the RPV internals components for FIVs due to SPU and summarized the analyses results of critical components in SPU LR Tables 2.2.3-1 and 2.2.3-2. The maximum calculated alternating stresses are very small, compared to the endurance limit of the component material. Therefore, the evaluation demonstrates that fatigue due to FIV is not an issue at SPU conditions.

The licensee has also evaluated the SPU impact on the licensing renewal SER for RVIs and has concluded that the aging evaluations the NRC staff approved for the RPV internal components in NUREG-1838 remain valid for SPU.

The licensee demonstrated that, overall, the maximum stress intensity ranges and cumulative fatigue usage factors for the RPV internals continue to meet ASME limits. Therefore, based on its review as summarized above, the NRC staff concludes that the effects of SPU do not adversely affect the structural integrity of the RPV internal components and core support structures.

Conclusion

The NRC staff has reviewed the licensee's evaluations related to the structural integrity of reactor internals and core supports and concludes that the licensee has adequately addressed the effects of the proposed SPU on the reactor internals and core supports. The NRC staff further concludes that the licensee has demonstrated that the reactor internals and core supports will continue to meet the requirements of 10 CFR 50.55a, GDC-1, GDC-2, GDC-4, and GDC-10 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the design of the reactor internal and core supports.

2.2.4 Safety-Related Valves and Pumps

Regulatory Evaluation

The NRC's staff's review included certain safety-related pumps and valves typically designated as Class 1, 2, or 3 under Section III of the ASME B&PV Code and within the scope of Section XI of the ASME B&PV Code and the ASME O&M Code, as applicable. The NRC staff's review focused on the effects of the proposed SPU on the required functional performance of the valves and pumps. The review also covered any impacts that the proposed SPU may have on the licensee's motor-operated valve (MOV) programs related to GL 89-10,[63], GL 96-05,[64] and GL 95-07.[65] The NRC staff also evaluated the licensee's consideration of lessons learned from the MOV program and the application of those lessons learned to other safety-related power-operated valves. The NRC's acceptance criteria are based on: (1) GDC-1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC 37, GDC 40, GDC 43, and GDC 46, insofar as they require that the ECCS, the containment heat removal system, the containment atomospheric cleanup systems, and the cooling water system, respectively, be designed to permit appropriate periodic testing to ensure the leak-tight integrity and performance of their active components; (3) GDC-54, insofar as it requires that piping systems penetrating containment be designed with the capability to periodically test the operability of the isolation valves to determine if valve leakage is within acceptable limits; and (4) 10 CFR 50.55a(f), insofar as it requires that pumps and valves subject to that section must meet the inservice testing (IST) program requirements identified in that section. Specific review criteria are contained in SRP Sections 3.9.3 and 3.9.6, and other guidance provided in Matrix 2 of RS-001.

Technical Evaluation

In its submittal dated July 13, 2007, requesting a license amendment to operate MPS3 at SPU conditions, the licensee discussed its evaluation of safety-related valves and pumps to perform their intended functions under SPU conditions. The NRC staff has reviewed the licensee's evaluation of the impact of SPU conditions on safety-related valves and pumps at MPS3. This review is summarized in the following paragraphs.

In response to GL 89-10, and GL 96-05, MPS3 established a testing and surveillance program for MOVs. The NRC acceptance of the MOV program for MPS3 was documented in a letter dated May 14, 1998. In a letter dated June 9, 2000,[66] the NRC attached the SE for MPS3's response to GL-96-05, and stated that MPS3 had established an acceptable program to periodically verify the design-basis capability of the safety-related MOVs through the actions described in its submittals. In its request for the SPU license amendment, the licensee described its evaluation of the MOVs within the scope of GL 89-10 at MPS3 for the effects of the proposed SPU, including those related to pressure locking and thermal binding as addressed in

[63] GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," dated June 28, 1989 (NUDOCS No.8906290082)
[64] GL 96-05, "Periodic Verification of Design Basis Capability of Safety-Related Motor-Operated Valves," dated September 18, 1996 (NUDOCS No. 9609100488)
[65] GL 95-07, "Pressure Locking and Thermal Binding of Safety-Related Power-Operated Gate Valves," dated August 17, 1995. (NUDOCS No. 9508110268)
[66] ADAMS Accession No. ML003722156

GL 95-07. Licensee's review of affected systems indicates that the existing maximum operating conditions (e.g., flow rates, pressures and temperatures) remain valid for the SPU. Therefore, no changes were identified to the design functional requirements for the GL 89-10 MOVs. The MOVs were also evaluated for pressure locking and thermal binding under SPU conditions, and no new MOVs were determined to susceptible to pressure locking or thermal binding.

MPS3 has a program in place for testing, inspection, and maintenance of air-operated valves (AOVs). The licensee has reviewed system level design basis calculations for Category 1 AOVs in the main steam system (MSS), service water system, and CVCS system. The results of the evaluation show that the SPU does not affect the maximum differential pressures, flow rates, or fluid temperatures for the design basis conditions. Therefore, the SPU has no impact on the setup values for these AOVs, and the existing design pressure and temperatures are adequate for these valves.

The Licensee's review of affected systems indicates that the existing maximum operating conditions, (i.e., flow rates, pressures and temperatures) remain valid for the SPU. Therefore, there is no change in the pump head performance for the affected safety-related pumps at the SPU conditions. Therefore, pump designs and IST Program requirements for these pumps are not affected by the SPU.

In its submittal, the licensee described its review of the IST Program for safety-related pumps and valves at MPS3 for SPU operations. The original Code of record for MPS3 is the 1980 Edition through winter 1980 Addenda of the ASME Code, Section XI. The IST Program at MPS3 assesses the operational readiness of pumps and valves within the scope of the ASME Section XI Code. The scope of the IST Program at MPS3, and the testing frequencies, will not be affected by the SPU. The IST program must be periodically updated to meet applicable ASME O&M Code requirements specified in 10 CFR 50.55a.

MPS3 has access to sources of both in-house and industry operating experience, and has a program which provides instruction and guidance for receiving, evaluating, and incorporating industry experience into the MOV program. If an adverse condition is identified which affects MPS3, a condition report is generated in accordance with station requirements, and applicable issues are evaluated and placed in the Corrective Action Program via the condition reports. MPS3 also has an AOV program and personnel responsible for AOV program would participate and interact with industry groups dedicated to the enhancement of AOV performance. Data on AOV performance collected through industry-wide cooperation are evaluated and utilized to enhance the AOV program.

Conclusion

The NRC staff has reviewed the licensee's assessments related to the functional performance of safety-related valves and pumps and concludes that the licensee has adequately addressed the effects of the proposed SPU on safety-related pumps and valves. The NRC staff further concludes that the licensee has adequately evaluated the effects of the proposed SPU on its MOV programs related to GL 89-10, GL 96-05, and GL 95-07, and the lessons learned from those programs to other safety-related power-operated valves. Based on this, the NRC staff concludes that the licensee has demonstrated that safety-related valves and pumps will continue to meet the requirements of GDC-1, GDC-37, GDC-40, GDC-43, GDC-46, GDC-54,

and 10 CFR 50.55a(f) following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to safety-related valves and pumps.

2.2.5 Seismic and Dynamic Qualification of Mechanical and Electrical Equipment

Regulatory Evaluation

Mechanical and electrical equipment covered by this section includes equipment associated with systems that are essential to emergency reactor shutdown, containment isolation, reactor core cooling, and containment and reactor heat removal. Equipment associated with systems essential to preventing significant releases of radioactive materials to the environment are also covered by this section. The NRC staff's review focused on the effects of the proposed SPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated pipe-whip and jet impingement forces. The primary input motions due to the safe shutdown earthquake (SSE) are not affected by an SPU. The NRC's acceptance criteria are based on: (1) GDC-1, insofar as it requires that SSCs important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-30, insofar as it requires that components that are part of the RCPB be designed, fabricated, erected, and tested to the highest quality standards practical; (3) GDC-2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; (4) 10 CFR Part 100, Appendix A, which sets forth the principal seismic and geologic considerations for the evaluation of the suitability of plant design bases established in consideration of the seismic and geologic characteristics of the plant site; (5) GDC-4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (6) GDC-14, insofar as it requires that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of rapidly propagating fracture; and (7) 10 CFR Part 50, Appendix B, which sets quality assurance requirements for safety-related equipment. Specific review criteria are contained in SRP Section 3.10.

Technical Evaluation

At SPU conditions, the seismic design inputs remain unchanged. Therefore, the NRC staff concurs with the licensee that the proposed power uprate does not affect the seismic qualification of essential equipment. The NRC staff finds that the equipment will continue to meet the requirements of GDCs 1, 2, 4, 14, and 30; 10 CFR Part 100, Appendix A, and 10 CFR Part 50, Appendix B, following implementation of the proposed SPU.

The current structural design basis of MPS3 implements the guidance of GDC-4 to include the application of LBB methodology thus eliminating consideration of the dynamic effects resulting from pipe breaks in the RCS primary loop piping. Following the implementation of LBB methodology, the governing RCS pipe breaks in the design basis of MPS3 are the RCL branch line breaks which include: the RHR pump suction lines off of the loop A and loop D hot legs; the pressurizer surge line off of the loop B hot leg; and the safety injection line off of Loops A, B, C and D. The licensee's analyses also included main steam and FLBs. The NRC staff's review of the MPS3 pipe break evaluation for SPU is contained in Section 2.2.1 of this SER, where it is shown that no new pipe break locations were identified for the SPU conditions and the jet

impingement and pipe whip restraints remain unaffected by the proposed power uprate. Therefore, the NRC staff agrees with the licensee that the qualification of equipment to withstand the dynamic effects associated with pipe-whip and jet impingement forces is not affected by the SPU.

Conclusion

The NRC staff has reviewed the licensee's evaluations of the effects of the proposed SPU on the qualification of mechanical and electrical equipment and concludes that the licensee has:
(1) adequately addressed the effects of the proposed SPU on this equipment, and
(2) demonstrated that the equipment will continue to meet the requirements of GDCs 1, 2, 4, 14, and 30; 10 CFR Part 100, Appendix A, and 10 CFR Part 50, Appendix B, following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the qualification of the mechanical and electrical equipment.

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

Regulatory Evaluation

Environmental qualification (EQ) of electrical equipment involves demonstrating that the equipment is capable of performing its safety function under significant environmental stresses which could result from DBAs. The NRC staff's review focused on the effects of the proposed SPU on the environmental conditions that the electrical equipment will be exposed to during normal operation, AOOs, and accidents. The parameters considered for normal operation and design basis accidents are temperature, pressure, radiation dose, humidity, spray chemistry, and submergence. The NRC staff's review was conducted to ensure that the electrical equipment will continue to be capable of performing its safety functions following implementation of the proposed SPU. The NRC's acceptance criteria for EQ of electrical equipment are based on 10 CFR 50.49, which sets forth requirements for the qualification of electrical equipment important to safety that is located in a harsh environment. Specific review criteria are contained in SRP Section 3.11.

Technical Evaluation

Containment

The SPU does not change the pressure or humidity of the containment under normal operations and thus, there is no effect on the qualified life of components. The licensee stated in its July 13, 2007, letter that although the normal radiation level in the containment increases under SPU conditions, the equipment remains qualified. For normal operations, a 120 °F temperature was used to determine qualified life. The SPU does not alter this temperature and thus, the EQ evaluations remain bounding. MPS3 utilizes local area temperature monitoring for components whose EQ documentation indicates credit for local area temperatures that are less than the design temperature.

Under accident conditions, SPU operation does not affect the 100-percent humidity assumed in the EQ evaluations. The accident pressure profile is shown in Figure 2.3.1-2 of the license amendment request (LAR) and the SPU accident peak pressure is bounded by the current EQ qualification pressure except for the time frame between 1,800 seconds and 20,000 seconds. The licensee stated that the slight increase in pressure due to the SPU does not affect the qualification of equipment since the tested conditions envelope the SPU peak pressure. Figure 2.3.1-1 of the LAR shows the containment accident temperature profile. The SPU conditions are bounded by the current EQ temperature profile except for between 1,800 seconds and 20,000 seconds. The licensee stated that a comparison was performed to ensure the SPU profile is bounded by EQ test profiles and the comparison showed that all equipment was bounded by the test profiles and therefore, unaffected by the SPU. The licensee further stated that the total integrated dose, 2.4E8 RADS, for containment, envelopes the post-LOCA total integrated dose for accident conditions.

Engineered Safety Features Building and Auxiliary Building

In its LAR, the licensee stated that under normal conditions, the temperature, pressure, humidity and radiation did not change due to the SPU in the engineered safety features (ESF) building. Under accident conditions, there is no change in accident temperature, pressure, and humidity at SPU conditions. The accident total integrated dose increases from 1.3E7 to 1.6E7 RADS due to the SPU. The licensee states in the LAR that the increased radiation levels may impact the qualification requirements of equipment in the ESF building. The NRC staff requested additional information regarding the EQ evaluations of the affected equipment. In its April 29, 2008, letter,[67] the licensee stated that plant walkdowns and design document reviews were performed for safety-related equipment to determine if additional equipment needed to be added to the EQ program as a result of the increased radiation. The licensee evaluated the component locations with respect to the gamma source term and the extent of beta shielding on the equipment. The licensee stated that the analysis shows that the component total integrated dose is below the dose threshold required for inclusion in the EQ program. Based on the above information, the NRC staff finds that the EQ evaluations for the ESF building are acceptable.

For the auxiliary building, the temperature, pressure, and humidity remain unchanged for normal operation and under accident conditions as a result of the SPU. The accident total integrated dose increases from 1.7E7 to 3.0E7 RADS due to the SPU. The licensee states in its LAR that increased radiation levels in certain zones of the auxiliary building may impact the qualification requirements of equipment. The NRC staff requested additional information regarding the qualification of affected equipment in the Auxiliary Building. In its April 29, 2008, letter, the licensee stated that plant walkdowns and design document reviews were performed for safety-related equipment to determine if additional equipment needed to be added to the EQ program as a result of the increased radiation. The licensee evaluated the component locations with respect to the gamma source term and the extent of beta shielding on the equipment. The licensee stated that the analysis shows that the component total integrated dose is below the dose threshold required for inclusion in the EQ program. Based on the above information, the NRC staff finds that the EQ evaluations for the auxiliary building are acceptable.

Main Steam Valve Building

The licensee stated in the LAR that under normal operation, the temperature, pressure, humidity, and radiation did not change due to the SPU in the main steam valve building (MSVB). Under accident conditions, the peak pressure and humidity are unaffected by the SPU. The accident temperature increases in the MSVB, following a main steamline break (MSLB) from 500 °F to 562.5 °F. The calculated peak post-SPU operating temperature of 562.5 °F exceeds the existing qualification temperature for the following equipment: American Switch Co. (ASCO) solenoid valves, NAMCo limit switches, Rosemount pressure transmitters, Limitorque motor operated valves, Sulzer main steam line isolation valve solenoids, and ITT Corporation damper actuators.

The limiting MSVB environments were determined by analyzing MSVB high energy line break (HELB) cases. Examples of cases included those that resulted in the maximum enthalpy of the steam released, those that maximized the duration of the transient or for the T_{avg} coastdown. The licensee stated in its April 29, 2008, letter, a thermal-lag analysis was performed for the

[67] ADAMS Accession No. ML081200643

required components to determine the peak component temperature at the time it is required to perform its design function. Basically, the analysis is performed for the component's mission time, the time from the initiation of the HELB to the point when the component is required to perform its intended design function.

The licensee stated in its April 29, 2008, letter that the ASCO solenoid valves de-energize such that the valves change to the required safe position under a HELB environment. The licensee further stated that using the maximum mission time of 1,800 seconds, the SPU peak coil temperature was calculated to be 445 °F and remains below the ASCO solenoid valve qualification temperature of 450 °F. Based on this information, the NRC staff finds that the ASCO solenoid valves are qualified for SPU.

The NAMCo limit switches serve to complete the electrical circuit when the contacts are closed and an open circuit when the contacts are opened following an HELB environment. In the thermal lag analysis of these components, the mission time for each specific break size was used. The licensee stated in its April 29, 2008, letter that the highest peak temperature occurred at 1,613 seconds. The licensee further stated that at 1,613 seconds, the calculated temperature of the phenolic inner casing is 338 °F, which is below the 340 °F qualification temperature for the most limiting NAMCo limit switch model. In its May 15, 2008, letter,[68] the licensee stated that the limit switches provide valve position indication and that the failure of the limit switches does not impact the position of the valve and other methods for monitoring valve position are available. The limit switches also function in air-operated valve seal-in circuits to hold the valve open. Once the valves move to their fail safe position (closed), the failure of the limit switches would not cause the reopening of the valve. Furthermore, the limit switches provide position permissive signals to the hydraulic controls of the feedwater isolation valves, and the failure of the limit switches do not affect the closure or re-opening of the valves. The licensee stated in its May 15, 2008, letter that the failure of the switches does not affect any other systems. The NRC staff finds this acceptable.

The Rosemount pressure transmitters provide signals to the main steam isolation valves (MSIV) for steam line low pressure isolation. Using a bounding temperature profile and a maximum mission time of 1,800 seconds, the licensee calculated the component peak temperature, 276 °F, which remains less than the qualification temperature of 318 °F. Based on this information, the NRC staff finds this acceptable.

For the Limitorque motor operated valves, the licensee determined that the motors require insulation to maintain the motor temperature below the qualification temperature during an MSVB HELB event. The licensee stated in its April 29, 2008, letter, that a design change will install flexible blanket type insulation covering only the motor. The licensee stated in its May 15, 2008, letter, that the modification is not expected to impact the qualified life. In addition, the licensee will monitor the casing temperature before and after the modification to determine if the increased temperature in the MSVB will affect the service life of the Limitorque motor operated valves. The licensee further stated that the proposed design modification will maintain the original motor qualification (i.e., the test condition is applicable to the installed configuration). Based on this information, the NRC staff finds that with the modification, the Limitorque motor operated valves will continue to perform their design function under SPU MSVB HELB conditions.

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[68] ADAMS Accession No. ML081360625

The Sulzer Solenoid valves' safety function is to de-energize to close the MSIV. The licensee stated in its April 29, 2008, letter, that no electrical failure will prevent the MSIVs from performing its design function since it will move to its fail closed position as a result of the failure of the Sulzer solenoid valves. In addition, the failure of the valves will not result in the reopening of an MSIV during the event. Thus, the NRC staff agrees that the Sulzer solenoid valves are not required to be electrically qualified for the temperature increase in the MSVB as a result of the SPU.

In the March 25, 2008, letter[69], the licensee stated that the ITT actuators are not required to mitigate the consequences of an MSLB in the MSVB. The NRC staff requested additional information regarding the function of the ITT actuators and the impact on other components or systems if the ITT actuators fail due to an MSLB under SPU conditions. In its April 29, 2008, letter, the licensee stated that the ITT actuators are part of the MSVB Ventilation System which provides cooling for components in the MSVB during normal operation. The licensee further stated that under accident conditions where a safety injection signal is generated, the MSVB Ventilation System is shut down to establish the Supplementary Leak Collection and Release System (SLCRS) boundary. SLCRS is designed for dose mitigation following an accident but the dose mitigation capability is not credited in the radiological consequences calculation for accidents OC (i.e., MSVB HELB) since the release point is the turbine building. Furthermore, the heat removal function of the MSVB Ventilation system is not credited in the environmental conditions calculation for MSVB HELB since the calculation assumes all dampers and vents are closed. The NRC staff agrees that the ITT actuators are not needed to mitigate the consequences of an MSLB in the MSVB.

Fuel Building

In the LAR, the licensee stated that the temperature, humidity, and pressure, under both normal and accident conditions, do not change due to SPU operation in the fuel building. However, the total integrated dose increased from 5.9 E+04 to 6.4 E+05 RADS, but the equipment remains qualified under SPU conditions. Therefore, the NRC staff agrees that the current EQ evaluations remain bounding for the fuel building.

Hydrogen Recombiner Building

Similarly, in the hydrogen recombiner building, there is no change in temperature, humidity, and pressure, under normal and accident conditions, due to SPU conditions. The accident radiation increased due to the SPU. Specifically, the total integrated dose increased from 9.2 E+05 to 9.4 E+05 RADS. The licensee stated in its LAR that the equipment remains qualified for SPU conditions. Thus, upon reviewing the LAR, the NRC staff agrees the current EQ evaluations for the hydrogen recombiner building remain bounding for SPU conditions.

Turbine Building

In the turbine building, as stated in the LAR, at normal conditions, the temperature, pressure, and humidity do not change due to the SPU. Under accident conditions, the total integrated dose remains mild for radiation and thus, does not impact EQ. The pressure for the turbine building from a MSLB remains bounding for SPU conditions.

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[69] ADAMS Accession No. ML080850894

The temperature analysis is no longer bounding for SPU conditions as the EQ evaluations had used conditions at 102-percent power. As stated in the January 10, 2008, letter,[70] two component types, listed in the EQ Master List, are in the turbine building. These components, turbine first stage pressure transmitters and main steam turbine stop valve position switches, will be removed from the EQ Master List and thus, do not require further evaluation.

The licensee stated, in its January 10, 2008, letter, that the turbine first stage pressure transmitters are not credited in any accident analyses but are included in the EQ program to ensure that the failure of these components will not adversely impact the plant's response to a design basis event. One function of the transmitters is to provide input to the rod control system, where a transmitter failure could initiate a rod withdrawal demand signal coincident with a steam line break. The licensee stated that modifications are being made to the rod control system to eliminate the capability for automatic rod withdrawal and thus, the failure of the transmitters could only result in a rod insertion signal, which is a conservative action.

The main steam stop valve position switches provide a reactor trip, a plant process computer input, position indication lights, and a position alarm in the control room (CR). The position switches are in the EQ program based on being associated with the safety-related reactor trip circuits. The licensee stated in its January 10, 2008, letter, that the switches are electrically isolated from the reactor trip circuits and do not perform any safety-related functions. Furthermore, the LAR proposes to eliminate EQ temperature monitoring in the turbine building. As such, the NRC staff agrees that these limit switches can be removed from the EQ program.

Impact on License Renewal

In the January 10, 2008, letter, the licensee stated, in regards to license renewal, that the EQ program will re-evaluate EQ components to ensure that the current qualification remains valid for the period of extended operation. The licensee also states that the SPU will not have any impact on the EQ program's ability to adequately manage the effects of aging on the intended functions of EQ components. The NRC staff requested additional information regarding why the SPU has no impact on the EQ program in regards to license renewal. The NRC Safety Evaluation Report for MPS3 license renewal (NUREG-1838) concludes that the MPS3 EQ program can adequately manage the effects of aging on the intended function(s) of safety-related EQ electrical components during the period of extended operation. Thus, the EQ program will re-evaluate the EQ components with a qualified life of 40 years or more to ensure that the current qualification remains valid for the period of extended operation. Based on the above, the NRC staff finds that the SPU will not affect the qualification of EQ components and that the EQ program will adequately manage the effects of aging.

Upon reviewing the LAR and its supplements, the NRC staff agrees that the EQ evaluations are acceptable and continue to meet the requirements of 10 CFR 50.49.

[70] ADAMS Accession No. ML080100600

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the EQ of electrical equipment and concludes that the licensee has adequately addressed the effects of the proposed SPU on the environmental conditions for and the qualification of electrical equipment. The NRC staff further concludes that the electrical equipment will continue to meet the relevant requirements of 10 CFR 50.49 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the EQ of electrical equipment.

2.3.2 Offsite Power System

Regulatory Evaluation

The offsite power system includes two or more physically independent circuits capable of operating independently of the onsite standby power sources. The NRC staff's review covered the descriptive information, analyses, and referenced documents for the offsite power system, and the stability studies for the electrical transmission grid. The NRC staff's review focused on whether the loss of the nuclear unit, the largest operating unit on the grid, or the most critical transmission line will result in the loss-of-offsite power (LOOP) to the plant following implementation of the proposed SPU. The NRC's acceptance criteria for offsite power systems are based on GDC-17. Specific review criteria are contained in SRP Sections 8.1 and 8.2, Appendix A to SRP Section 8.2, and BTPs PSB-1 and ICSB-11.

Technical Evaluation

Power Block Equipment (Generator, Exciter, Transformers, Iso-phase bus duct, Generator circuit breaker)

As a result of the power uprate, the rated thermal power will increase to 3650 MWt from the previously analyzed core power level of 3411 MWt. Operation at this value corresponds to 0.957 lagging power factor at stretch power uprate conditions.

The main generator was rated at 1354.7 megavolt ampere (MVA) at 0.925 power factor, corresponding to 1253.1 MW. The licensee's evaluation has shown that the generator can perform at an increased power factor without any modifications. Thus, the generator will be operating at 1296 MW and 0.957 power factor.

As shown in Table 2.3.3-6 in the LRA, the worst-case SPU loading on the main bus of the isolated phase bus duct is 34.3 kA and is enveloped by the continuous current design rating of 34.4 kiloamps (kA). The isolated phase bus duct connected to the normal station service transformer (NSST) B will experience an increase in load current due to the increased load on the reactor coolant pumps. Table 2.3.3-7 demonstrates that the load current of 1.1 kA is below the continuous current design rating of 4.0 kA. The isolated phase bus duct to NSST A remains unaffected by the SPU. The isolated phase bus duct to main transformers A and B will be loaded to 17.1 kA and 17.2 kA, respectively, and both remain under the continuous current design rating of 18.8 kA as shown in Table 2.3.3-8. Therefore, the NRC staff finds that the isolated phase bus ducts remain acceptable under SPU conditions.

The licensee evaluated the generator circuit breaker under worst-case SPU loading conditions. The generator outputs 34.3 kA, which is bounded by the generator circuit breaker rating of 37.5 kA.

The worst-case loading on the main transformers occurs when the reserve station service transformers (RSSTs) supply the station auxiliary loads and the unit is operating at full SPU conditions. Table 2.3.2-1 shows the output loads for main transformer A and B are 652.6 MVA and 658.1 MVA, which are bounded by the design rating of 840 MVA. For RSST A, the existing analysis remains bounding, as there are no significant load changes on the Class 1E safety buses. RSST B will experience increased loading due to reactor coolant pump brake horsepower load increases. The worst-case loading on RSST B occurs when NSST B is out of service and station auxiliary loads on the 6.9 kV bus are supplied solely from RSST B. For the X and Y windings of RSST B, the total output load for SPU conditions is 18.48 MVA and 23.85 MVA, respectively, and both are under the design rating of 25 MVA. The H winding of RSST B will see 43.91 MVA under SPU conditions, which is bounded by the design rating of 50 MVA. For NSST A, the existing analysis remains bounding, as there are no significant load changes on the 4.16 kV buses. Due to the increase in loading on the reactor coolant pump brake horsepower load, the loading on NSST B increases to 43.64 MVA and remains bounded by the design rating of 50 MVA.

Tie-lines between the main transformers and switchyard and between the switchyard and RSSTs were evaluated by the licensee under SPU conditions. The evaluation determined that the increase in output ampacity will not raise the conductor temperature above its 75 °C rating.

The NRC staff reviewed the licensee's evaluation of the main transformers, NSSTs, RSSTs, isolated phase bus ducts, and generator circuit breaker and agrees that they remain acceptable under SPU conditions.

Emergency Diesel Generators (EDGs)

The EDG system provides a safety-related source of alternating current (ac) power to sequentially energize and restart loads necessary to shutdown the reactor safely, and to maintain the reactor in a safe shutdown condition. There are two EDG sets, each dedicated to one of the safety-related 4.16 kV buses.

There are no significant changes in EDG system loads due to the SPU. Therefore, the NRC staff agrees that there is no impact to the existing EDG loading analysis, and the EDGs remain acceptable for SPU operation.

Switchyard

The switchyard equipment and associated components are classified as non-safety related. The primary function of the 345 kV switchyard and distribution system is to connect the station electrical system to the transmission grid. The interconnection allows for: (1) the normal flow of power out of the station to the grid when the main generator is operating; and (2) the flow of power from the grid to the station auxiliaries when the main generator is shut down.

The licensee stated that no changes were required to the 345 kV switchyard equipment or associated components. The 345 kV switchyard equipment ratings were determined to bind the SPU operating conditions.

The NRC staff reviewed the LAR and therefore, the staff agrees that the analyses for switchyard system reasonably bound the stretch power uprate conditions.

Grid Stability

A system reliability impact study evaluated the impact of the power uprate on the reliability of the local 345 kV and surrounding bulk power systems. The generator has been analyzed for a gross power output of 1276 MW (summer) and 1296 MW (winter) with a power factor of 0.957, resulting in a maximum of 445 megavolt ampere reactive (MVAR) (summer) and 395 MVAR (winter). The station service loads were modeled at 50 MW and 37 MVAR at SPU conditions.

The stability and voltage analyses were performed on 2009 summer peak and light load cases. Load flow studies were performed for both pre-contingency and post-contingency cases.

The voltage studies indicated no adverse impacts and that the minimum 345 kV and maximum 362.25 kV voltages would be maintained at MPS3. The grid remained stable for all analyzed contingencies. The loss of MPS3 or any other generating unit in the system did not result in cascading system outages nor cause LOOP to the units. These studies also demonstrated that short circuit magnitudes and breaker clearing times were acceptable. Additionally, under transmission system stressed conditions, line loadings remained within current ratings.

In its January 10, 2008, letter, the licensee stated that the SPU will result in a decrease of 42 MVARs in the summer and 102 MVARs in the winter. The system reliability impact study incorporated these changes. The analysis indicates that the decrease in MVARs does not impact grid stability and the steady-state and dynamic performance of MPS3 at SPU conditions remains acceptable.

Upon reviewing the LAR, the NRC staff agrees that the steady-state and dynamic performance of MPS3 at uprated conditions remains acceptable.

<u>Conclusion</u>

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the offsite power system and concludes that the offsite power system will continue to meet the requirements of GDC-17 following implementation of the proposed SPU. Adequate physical and electrical separation exists and the offsite power system has the capacity and capability to supply power to all safety loads and other required equipment. The NRC staff further concludes that the impact of the proposed SPU on grid stability is insignificant. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the offsite power system.

2.3.3 AC Onsite Power System

Regulatory Evaluation

The AC onsite power system includes those standby power sources, distribution systems, and auxiliary supporting systems provided to supply power to safety-related equipment. The NRC staff's review covered the descriptive information, analyses, and referenced documents for the AC onsite power system. The NRC's acceptance criteria for the AC onsite power system are based on GDC-17, insofar as it requires the system to have the capacity and capability to perform its intended functions during AOOs and accident conditions. Specific review criteria are contained in SRP Sections 8.1 and 8.3.1.

Technical Evaluation

The AC distribution system is the source of power to non-safety-related buses, and to safety-related emergency buses supplying the redundant ESFs loads. It consists of the 6.9 kilovolt (kV) system, the 4.16 kV system (not including the EDGs), the 480 volt (V) system and the 120 V system.

The 6.9 kV system supplies power to large non-Class 1E motor loads. As indicated in Table 2.3.3-2 in the LAR, the SPU loading requirements of switchgear buses, incoming circuit breakers and rectangular non-segregated phase bus ducts are within the equipment ratings. The condensate pump and SG feedwater pump motor load requirements remain within the nameplate ratings and are within the brake horsepower loads in the existing load flow/voltage profile analysis as stated in the July 13, 2007, letter. The reactor coolant pumps worst-case hot-loop load under SPU conditions is 7201 hp, exceeding the 7000 horsepower (hp) motor nameplate rating for hot-loop operation. Similarly, the worst-case cold-loop load is 9183 hp, exceeding the rating of 8750 hp. Thus, the licensee evaluated the stator winding temperature rise value. As shown in Section 2.2.2.6.2.3 of the LAR, the predicted temperature rises will be 65.9 °C (hot) and 88.3 °C (cold), which are under the ratings of a rise above the 50 °C ambient of 75 °C (hot) and 100 °C (cold). Additionally, the thrust bearing loads for the reactor coolant pumps were evaluated to be within the thrust bearing design rating. Thus, the 6.9 kV system remains acceptable under SPU conditions.

The 4.16 kV system provides power to non-Class 1E and Class 1E loads. The licensee stated in its January 10, 2008, letter, that the brake horsepower at SPU conditions for the heater drain pump motors and moisture separator drain pump motors remain within the nameplate ratings and are within the brake horsepower loads used in the existing analyses.

The 480 V system supplies low voltage power for the operation of non-Class 1E and Class 1E loads, through load centers and motor control centers. In regards to the 480 V system, the load flow/voltage profile is unaffected since there are no load changes. Therefore, the 480 V system remains bounded by the existing voltage profile analyses. The 120 V AC system provides regulated and uninterruptible power to vital controls and instrument loads. As there are no load changes to the 120 V AC system due to the SPU, the NRC staff agrees that the 120 V AC system remains bounded by the existing analyses.

The NRC staff reviewed the license application and found that there are no significant changes in AC distribution system loads. Therefore, the NRC staff agrees that the analyses for AC distribution system reasonably bounds the stretch power uprate conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the AC onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed SPU on the system's functional design. The NRC staff further concludes that the AC onsite power system will continue to meet the requirements of GDC-17 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the AC onsite power system.

2.3.4 DC Onsite Power System

Regulatory Evaluation

The direct current (DC) onsite power system includes the DC power sources and their distribution and auxiliary supporting systems that are provided to supply motive or control power to safety-related equipment. The NRC staff's review covered the information, analyses, and referenced documents for the DC onsite power system. The NRC's acceptance criteria for the DC onsite power system are based on GDC-17, insofar as it requires the system to have the capacity and capability to perform its intended functions during AOOs and accident conditions. Specific review criteria are contained in SRP Sections 8.1 and 8.3.2

Technical Evaluation

The 125 V DC system is comprised of batteries, battery chargers and distribution equipment that supply power to station loads. The nuclear safety-related (Class 1E) portion of the DC system consists of four separate channels, two dedicated to supplying the regulated 120 V AC vital bus power supply, the other two supplying the 120 V AC vital bus as well as the other safety-related DC loads. Each channel of the Class 1E 125 V DC system consists of one operating battery charger, one spare battery charger shared by two channels of the same train, one 125 V DC battery, and one distribution switchboard. The 125 V DC power system provides the battery capacity to cope with a station blackout (SBO).

The licensee reviewed the BOP systems, including the turbine generator auxiliaries, and determined that no new DC loads were added nor were any DC load increases identified for the existing loads. Similarly, for the NSSS, there are no changes in the DC system loads. Furthermore, SBO and fire protection program (FPP)/safe shutdown evaluations revealed no changes in the 125 V DC system. Hence, the 125 V DC system is unaffected by the power uprate.

The DC power system is within the scope of license renewal, and operating the DC system at uprated conditions does not introduce any new aging effects. Hence, in regards to the 125 V DC system, the power uprate will not affect license renewal programs.

The NRC staff reviewed the LAR. There are no significant changes in DC system loads. Therefore, the NRC staff agrees that the DC power system will continue to function as designed and will continue to meet requirements.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the DC onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed SPU on the system's functional design. The NRC staff further concludes that the DC onsite power system will continue to meet the requirements of GDC-17 following implementation of the proposed SPU. Adequate physical and electrical separation exists and the system has the capacity and capability to supply power to all safety loads and other required equipment. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the DC onsite power system.

2.3.5 Station Blackout

Regulatory Evaluation

Station blackout (SBO) refers to a complete loss of AC electric power to the essential and nonessential switchgear buses in a nuclear power plant. SBO involves the LOOP concurrent with a turbine trip (TT) and failure of the onsite emergency AC power system. SBO does not include the loss of available AC power to buses fed by station batteries through inverters or the loss of power from "alternate AC sources" (AACs). The NRC staff's review focused on the impact of the proposed SPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The NRC's acceptance criteria for SBO are based on 10 CFR 50.63. Specific review criteria are contained in SRP Sections 8.1 and Appendix B to SRP Section 8.2; and other guidance provided in Matrix 3 of RS-001.

Technical Evaluation

As stated in 10 CFR 50.63, each light water cooled nuclear power plant must be able to withstand and recover from a loss of all AC power, referred to as Station Blackout (SBO).

An alternate AC source, an SBO diesel generator, is available to provide AC power to all systems required for coping with an SBO. MPS3 SBO coping duration is 8 hours. This is based on an evaluation of the offsite power design characteristics, emergency AC power system configuration and EDG target reliability, estimated frequency of LOOP due to severe weather, and estimated frequency of LOOP due to extremely severe weather.

The NRC staff reviewed the LAR and agrees that the SPU does not impact the offsite power design characteristics, modify the emergency AC power system configuration or affect the EDG reliability. Considering this, the NRC staff agrees that the stretch SPU will have no impact on MPS3 SBO coping duration. In addition, the SBO diesel generator is not impacted by the power uprate. Hence, MPS3 will continue to meet the requirements of 10 CFR 50.63.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the plant's ability to cope with and recover from an SBO event for the period of time established in the plant's licensing basis. The NRC staff concludes that the licensee has adequately evaluated the effects of the proposed SPU on SBO and demonstrated that the plant will continue to meet the requirements of 10 CFR 50.63 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to SBO.

2.4 Instrumentation and Controls

2.4.1 Reactor Protection, Safety Features Actuation, and Control Systems

Regulatory Evaluation

Instrumentation and control systems are provided: (1) to control plant processes having a significant impact on plant safety; (2) to initiate the reactivity control system (including control rods); (3) to initiate the ESF systems and essential auxiliary supporting systems; and (4) for use to achieve and maintain a safe shutdown condition of the plant. Diverse instrumentation and control systems and equipment are provided for the express purpose of protecting against potential common-MODE failures of instrumentation and control protection systems. The NRC staff conducted a review of the reactor trip system (RTS), engineered safety feature actuation system (ESFAS), safe shutdown systems, control systems, and diverse instrumentation and control systems for the proposed SPU to ensure that the systems and any changes necessary for the proposed SPU are adequately designed such that the systems continue to meet their safety functions. The NRC staff's review was also conducted to ensure that failures of the systems do not affect safety functions. The NRC's acceptance criteria are GDCs 13 and 20. The NRC staff also used Regulatory Guide (RG) 1.105, Revision 3, "Setpoints for Safety-Related Instrumentations." RG 1.105 describes a method acceptable to the NRC staff for complying with the NRC's regulations for ensuring that setpoints for safety-related instrumentation are initially within and remain within the TS limits. The RG endorses Part I of ISA-S67.04-1994, "Setpoints for Nuclear Safety Instrumentation," subject to the NRC staff clarifications.

Technical Evaluation

In response to the NRC staff's request for additional information, by letter dated January 18, 2008,[71] the licensee stated that the proposed setpoint changes were based on calculation methodology described in WCAP-10991, Rev.5, "Millstone Nuclear Power Station Unit 3, 24 Month Fuel Cycle Evaluation," dated August 1997, which the NRC approved by Amendment No. 159, dated May 26, 1998.[72] In this calculation, the AV is calculated as equal to the Nominal Trip Setpoint (NTSP) $\pm$ calibration tolerance. In the plant procedures for RTS and ESFAS instrument setpoint verification, the as-found (AF) acceptance criteria (the licensee has used the term "criteria" instead of "tolerance" because it is specified in the plant procedures) has been selected as equal to or less than the AV and the as-left (AL) acceptance criteria has been selected as half of the AF acceptance criteria. During setpoint surveillance testing, channels found to be within the AL criteria are considered as operable and do not require adjustment. Channels found outside the AL criteria but within the AF criteria are considered as operable and are adjusted to be within the AL criteria before completing the surveillance. Channels found outside of the AF criteria (i.e. AV) are inoperable until they can be reset acceptably to within the AL criteria, either through recalibration or corrective maintenance as specific conditions warrants. Plant condition reports are initiated for channels found outside the AF acceptance criteria. These condition reports are evaluated and trended to determine if additional corrective actions are necessary.

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[71] ADAMS Accession No. ML080220506
[72] ADAMS Accession No. ML011790264

Conclusion

The staff concludes that the licensee's methodology for calculating the total loop uncertainty, the As-Found acceptable criteria, As-Left acceptable criteria, AV, and NTSP conform to the RG 1.105, Revision 3, "Setpoints for Safety-Related Instrumentations," and therefore, acceptable. The licensee confirmed that the As-Found acceptable criteria and AV have the same value specified in the applicable plant procedures and they include calibration tolerance only and the As-Left acceptable criteria is used as half of the As-Found acceptable criteria. During setpoint surveillance testing, channels found to be outside the As-Left acceptable criteria but within the As-Found acceptable criteria are adjusted to be within the As-Left acceptable criteria. Channels found outside the As-Found acceptable criteria are inoperable until they can be reset within the As-Left criteria and plant condition reports are initiated and evaluated to determine if additional corrective actions are necessary. The NRC staff concludes that the systems will continue to meet the requirements of GDCs 13 and 20. Specific Technical Specification changes are reviewed in Section 3.0, "Facility Operating License and Technical Specification Changes."

2.5 Plant Systems

2.5.1 Internal Hazards

2.5.1.1 Flooding

2.5.1.1.1 Flood Protection

Regulatory Evaluation

The NRC staff conducted a review in the area of flood protection to ensure that SSCs important to safety are protected from flooding. The NRC staff's review covered flooding of SSCs important to safety from internal sources, such as those caused by failures of tanks and vessels. The NRC staff's review focused on increases of fluid volumes in tanks and vessels assumed in flooding analyses to assess the impact of any additional fluid on the flooding protection that is provided. The NRC's acceptance criteria for flood protection are based on GDC-2. Specific review criteria are contained in SRP Section 3.4.1.

Technical Evaluation

As described in Section 3.1 of the MPS3 Updated Final Safety Evaluation Report (UFSAR) and Section 2.5.1.1.1 of MPS3 LAR, the evaluation of internal flooding due to failures of non-seismic Category 1 tanks and vessels was based on release of fluid from the tanks. The licensee stated that the SPU does not affect the protection from internal flooding resulting from postulated failures of non-seismic Category 1 tanks and vessels, and there are no modifications to the tanks and vessels as a result of the proposed SPU.

Based on its review of Section 2.5.1.1.1 of the MSP3 LAR and the UFSAR related section, the NRC staff finds that SPU operating conditions will not: (1) increase the size or the amount of fluid in any of the non-Seismic Category 1 tanks and vessels located in safety-related structures outside the containment; (2) require the addition of any new non-Seismic Category 1 tanks or vessels; and (3) affect the location of existing safety-related equipment required for safe shutdown of the plant, nor does it require an addition of any new safety-related equipment required for safe shutdown. The staff, therefore, concludes that the proposed SPU does not affect the protection from internal flooding resulting from postulated failures of non-seismic Category 1 tanks and vessels.

Conclusion

The NRC staff has reviewed the proposed changes in fluid volumes in tanks and vessels for the proposed SPU. The NRC staff concludes that SSCs important to safety will continue to be protected from flooding and will continue to meet the requirements of GDC-2 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to flood protection.

2.5.1.1.2 Equipment and Floor Drains

Regulatory Evaluation

The function of the equipment and floor drainage system (EFDS) is to assure that waste liquids, valve and pump leakoffs, and tank drains are directed to the proper area for processing or disposal. The EFDS is designed to handle the volume of leakage expected, prevent a backflow of water that might result from maximum flood levels to areas of the plant containing safety-related equipment, and protect against the potential for inadvertent transfer of contaminated fluids to an uncontaminated drainage system. The NRC staff's review of the EFDS included the collection and disposal of liquid effluents OC. The NRC staff's review focused on any changes in fluid volumes or pump capacities that are necessary for the proposed SPU and are not consistent with previous assumptions with respect to floor drainage considerations. The NRC's acceptance criteria for the EFDS are based on GDCs 2 and 4 insofar as they require the EFDS to be designed to withstand the effects of earthquakes and to be compatible with the environmental conditions (flooding) associated with normal operation, maintenance, testing, and postulated accidents (pipe failures and tank ruptures). Specific review criteria are contained in SRP Section 9.3.3.

Technical Evaluation

As described in USFAR Section 3.1 and Section 2.5.1.1.2 of the MPS3 LAR, the licensee stated that SPU operations would not affect existing safety-related components in the EFDS; nor would it add any new equipment or modify existing equipment that would result in an increase in the quantity of liquids currently entering the EFDS.

Based on its review, the NRC staff finds that the proposed SPU does not result in any modifications to safety-related components and does not produce new water makeup sources that would challenge EFDS' ability to perform its drainage function. The current EFDS retains the original design and maintains a sufficient capacity to prevent the backflow of water to areas containing safety-related equipment. The staff, therefore, concludes that the EFDS continues to provide adequate drainage and collection protection as designed.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the EFDS and concludes that the licensee has adequately accounted for the plant changes resulting in increased water volumes and larger capacity pumps or piping systems. The NRC staff concludes that there are no changes to the EFDS and the EFDS has capacity to prevent the backflow of water to areas with safety-related equipment, and to ensure that contaminated fluids are not transferred to noncontaminated drainage systems. Based on this, the NRC staff concludes that the EFDS will continue to meet the requirements of GDCs 2 and 4 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the EFDS.

2.5.1.1.3 Circulating Water System

Regulatory Evaluation

The circulating water system (CWS) provides a continuous supply of cooling water to the main condenser (MC) to remove the heat rejected by the turbine cycle and auxiliary systems. The NRC staff's review of the CWS focused on changes in flooding analyses that are necessary due to increases in fluid volumes or installation of larger capacity pumps or piping needed to accommodate the proposed SPU. The NRC's acceptance criteria for the CWS are based on GDC 4 for the effects of flooding of safety-related areas due to leakage from the CWS and the effects of malfunction or failure of a component or piping of the CWS on the functional performance capabilities of safety-related SSCs. Specific review criteria are contained in SRP Section 10.4.5.

Technical Evaluation

The CWS provides a continuous supply of cooling water to the MC to remove excess heat from the steam turbine exhaust cycle and auxiliary systems. Based on its review of the effects of the proposed SPU, the NRC staff confirms that the CWS flow rate and pressure do not change at SPU conditions. Operating pressures and flow rates of the CWS do not change and the circulating water pumps continue to operate at the same flow and discharge head at SPU conditions. No physical changes were required for the CWS. The staff, therefore, concludes that no changes to existing flooding design and licensing are needed because of a circulating water pipe rupture or expansion joint failure.

Conclusion

The NRC staff review finds that the CWS will continue to meet the requirements of GDC-4 for the protection of safety-related equipment from flooding due to a break or leakage in the CWS. The heat load of the CWS was addressed in the Environmental Assessment.[73]

2.5.1.2 Missile Protection

2.5.1.2.1 Internally Generated Missiles

Regulatory Evaluation

The NRC staff's review concerns missiles that could result from in-plant component overspeed failures and high-pressure system ruptures. The NRC staff's review of potential missile sources covered pressurized components and systems, and high-speed rotating machinery. The NRC staff's review was conducted to ensure that safety-related SSCs are adequately protected from internally generated missiles. In addition, for cases where safety-related SSCs are located in areas containing non-safety-related SSCs, the NRC staff reviewed the non-safety-related SSCs to ensure that their failure will not preclude the intended safety function of the safety-related SSCs. The NRC staff's review focused on any increases in system pressures or component overspeed conditions that could result during plant operation, AOOs, or changes in existing system configurations such that missile barrier considerations could be affected. The

[73] ADAMS Accession No. ML081930070

NRC's acceptance criteria for the protection SSCs important to safety against the effects of internally generated missiles that may result from equipment failures are based on GDC 4. Specific review criteria are contained in SRP Sections 3.5.1.1 and 3.5.1.2.

Technical Evaluation

As discussed in MPS3 UFSAR Section 3.5.1 and LAR Section 2.5.1.2, safety-related SSCs are protected from internally generated missiles from sources inside and outside of containment. The licensee evaluated potential increases in system pressures or component overspeed conditions as a result of SPU operations, AOOs, or changes in existing system configurations such that missile barrier considerations could be affected.

The licensee proposes to replace the feedwater pump turbines and increase the rotor speed from 4,900 revolutions per minute (rpms) to 5,125 rpms. In response to the NRC staff's RAI, the licensee stated in a letter dated January 11, 2008, that the replaced feedwater pump turbine is of a newer design and is a like-in-kind replacement. The increase in rotor speed is minor with respect to generating missiles source from overspeed. The newer pump turbine retains the same design characteristic and classification as original and is bounded by the existing design considerations. There is no safety-related equipment in the vicinity of the new feedwater pumps that could be impacted by this missile source.

Conclusion

The NRC staff has reviewed the changes in system pressures and configurations that are required for the proposed SPU and concludes that SSCs important to safety will continue to be protected from internally generated missiles and will continue to meet the requirements of GDC 4 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to internally generated missiles.

2.5.1.2.2 Turbine Generator

Regulatory Evaluation

The turbine control system, steam inlet stop and control valves, low pressure turbine steam intercept and inlet control valves, and extraction steam control valves control the speed of the turbine under normal and abnormal conditions, and are thus related to the overall safe operation of the plant. The NRC staff's review of the turbine generator focused on the effects of the proposed SPU on the turbine overspeed protection features to ensure that a turbine overspeed condition above the design overspeed is very unlikely. The NRC's acceptance criteria for the turbine generator are based on GDC 4, and relates to protection of SSCs important to safety from the effects of turbine missiles by providing a turbine overspeed protection system (with suitable redundancy) to minimize the probability of generating turbine missiles. Specific review criteria are contained in SRP Section 10.2.

Technical Evaluation

The main turbine system includes one high-pressure turbine and three low-pressure turbines, all mounted on a common shaft. The electro-hydraulic control unit provides a normal and an emergency overspeed protection by fully closing the turbine control valves at 105 percent of

rated speed. The emergency overspeed protection is also designed to trip the turbine if the speed reaches 110 percent of rated speed. The electrical backup overspeed sensor will also trip these same control valves at 111 percent of rated speed and independently de-energize the hydraulic fluid system. The turbine overspeed protection is part of the methodology used to ensure the probability of generating turbine missiles is kept below 1E-05 per year. This probability consists of two components: (1) the probability of turbine missile generation due to material degradation at normal operating speeds up to 120 percent of rated speed; and (2) the probability of turbine missile generation due to overspeed protection system failure resulting in speeds greater than 120 percent of rated speed.

The existing turbine overspeed trip setpoint of 110 percent would not be affected by the implementation of SPU and would continue to ensure that the design overspeed limit of 120 percent would not be exceeded.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the turbine generator and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on turbine overspeed. The NRC staff concludes that the turbine generator will continue to provide adequate turbine overspeed protection to minimize the probability of generating turbine missiles and will continue to meet the requirements of GDC 4 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the turbine generator.

2.5.1.3 Pipe Failures

Regulatory Evaluation

The NRC staff conducted a review of the plant design for protection from piping failures OC to ensure that: (1) such failures would not cause the loss of needed functions of safety-related systems; and (2) the plant could be safely shut down in the event of such failures. The NRC staff's review of pipe failures included high and moderate energy fluid system piping located outside of containment. The NRC staff's review focused on the effects of pipe failures on plant environmental conditions, CR habitability, and access to areas important to safe control of post-accident operations where the consequences are not bounded by previous analyses. The NRC's acceptance criteria for pipe failures are based on GDC 4, which requires, in part, that SSCs important to safety be designed to accommodate the dynamic effects of postulated pipe ruptures, including the effects of pipe whipping and discharging fluids. Specific review criteria are contained in SRP Section 3.6.1.

Technical Evaluation

The impact and consequences of high energy line breaks (HELBs) and moderate energy piping system cracks are postulated to occur OC and are discussed in USFAR Section 3.6.1 and Section 2.5.1 of the MSP3 SPU LAR. With the exception of the postulated main steam and feedwater system operating parameters, the design temperatures and pressures remain within the values used for analyses of postulated pipe failures. In addition, the licensee's evaluation of SPU operating conditions identified no new or revised pipe break locations and the SPU modifications introduce no new equipment that must be protected from the effects of pipe

breaks. Therefore, for systems other than main feedwater and main steam, the pressure and temperature response for rooms and sub-compartments OC will not be impacted. Hence, there will be no increase in pipe whip or jet impingement forces. Existing jet shields and pipe whip restraints will continue to be adequate for SPU operation and existing analyses of the extent of flooding resulting from postulated pipe failures continue to be valid.

For a HELB in the MSVB, the MSVB temperature qualification profiles are impacted (i.e., peak temperature increases from 500°F to 565.5°F). Section 2.3 of this SE documents the assessment of the MSVB harsh environmental changes with respect tocredited SSCs. For a HELB in the turbine building (TB), SPU will increase the TB HELB temperature. The licensee proposes to revise the TB HELB safe shutdown analysis to eliminate crediting equipment located in the TB. A TB HELB has no adverse impact on credited SSCs, because no credited equipment is located in the TB and there is no impact to adjacent areas due to building layout or design. A staff review of pipe failures assessments by the licensee for all other buildings concluded that SPU has no adverse impact upon existing moderate of high energy pipe failure analysis.

In Section 2.5.1 of the MPS3 LAR, the licensee addresses impact from MSLB, recirculation pump piping, CCW piping, and flooding from the HELB of a SGBS line in the MSVB. The main feedwater lines also transit this area. However, the evaluation does not specifically address the increased mass release from an HELB in the feedwater system and its effect upon internal flooding. In response to an NRC staff RAI, dated January 11, 2008, with regard to the effect of a feedwater break at SPU conditions upon internal flooding, the licensee responded that the feedwater line in the MSVB from the containment penetration to column F wall (F-Wall) is a break exclusion zone. Therefore, a break is not postulated in this location. From the F-Wall to the turbine building, a break is postulated. However, there is no area for flood accumulation between the F-Wall and the turbine building, because the ground floor is an open truck bay and the upper floors are all grating. As a result, any discharge will quickly leave the building. The NRC staff reviewed UFSAR Section 3.6.1.3.3 and confirmed the room configuration.

Conclusion

The NRC staff has reviewed the changes that are necessary for the proposed SPU and the licensee's proposed operation of the plant, and concludes that SSCs important to safety will continue to be protected from the dynamic effects of postulated piping failures in fluid systems OC and will continue to meet the requirements of GDC 4 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to protection against postulated piping failures in fluid systems OC.

2.5.1.4 Fire Protection

Regulatory Evaluation

The purpose of the FPP is to provide assurance, through a defense-in-depth design, that a fire will not prevent the performance of necessary safe plant shutdown functions and will not significantly increase the risk of radioactive releases to the environment. The NRC staff's review focused on the effects of the increased decay heat on the plant's safe shutdown analysis to ensure that SSCs required for the safe shutdown of the plant are protected from the effects of the fire and will continue to be able to achieve and maintain safe shutdown following a fire. The

NRC's acceptance criteria for the FPP are based on: (1) 10 CFR 50.48 and associated Appendix R to 10 CFR Part 50, insofar as they require the development of an FPP to ensure, among other things, the capability to safely shut down the plant; (2) GDC-3, insofar as it requires that: (a) SSCs important to safety be designed and located to minimize the probability and effect of fires; (b) noncombustible and heat resistant materials be used; and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; and (3) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions. Specific review criteria are contained in SRP Section 9.5.1, as supplemented by the guidance provided in Attachment 2 to Matrix 5 of Section 2.1 of RS-001.

Technical Evaluation

The NRC staff's review of the July 13, 2007, LAR, Attachment 5, and Table 2.5.1.4-1, identified areas in which additional information was necessary to complete the review of the proposed SPU LAR. The licensee responded to the staff's RAI as discussed below.

In RAI AFPB-07-0006 from letter dated November 26, 2007,[74] the staff noted that RS-001, Revision 0, "Review Standard for Extended Power Uprates," Attachment 2 to Matrix 5, "Supplemental Fire Protection Review Criteria," states that "power uprates typically result in increases in decay heat generation following plant trips. These increases in decay heat usually do not affect the elements of a FPP related to:

(1) Administrative controls;

(2) Fire suppression and detection systems;

(3) Fire barriers;

(4) Fire protection responsibilities of plant personnel; and

(5) Procedures and resources necessary for the repair of systems required to achieve and maintain cold shutdown.

In addition, an increase in decay heat will usually not result in an increase in the potential for a radiological release resulting from a fire. However, the licensee's LAR should confirm that these elements are not impacted by the extended power uprate."

The staff notes that LAR Attachment 5, Section 2.5.1.4.2.2, "Description of Analyses and Evaluations", specifically addresses only item (1) above. The NRC staff requested that the licensee provide statements to address items (2) through (5), and a statement confirming no increase in the potential for a radiological release resulting from a fire. By letter dated December 17, 2007,[75] the licensee provided the following response.

[74] ADAMS Accession No. ML073170665
[75] ADAMS Accession No. ML073520051

SPU does not affect the design or operation of fire suppression/detection systems. SPU has no impact upon fire barriers installed to satisfy NRC fire protection requirements. SPU does not affect fire protection responsibilities of plant personnel. SPU does not affect procedures and resources for the repair of systems required to achieve and maintain cold shutdown.

Any fire barrier or combustible loading changes as a result of physical modifications necessary to implement SPU will be evaluated under the licensee's FPP.

DNC has confirmed that there is no significant increase in the potential for a radiological release resulting from a fire.

SPU LAR Attachment 5, LR, Section 2.5.1.4.2.2, “Fire Protection, Technical Evaluation, Description of Analysis and Evaluations,” addresses: (1) Administration; (2) Plant Design Features; (3) Fire Hazard Analysis; (4) Safety Shutdown Evaluation; (4) Support Systems; (5) Resolution of Safety Shutdown Evaluation Problem Areas; and (6) Operator Action Required Following a Fire. This Licensing Report section structure mirrors the Millstone-3 Fire Protection Evaluation Report (FPER) structure.

LR Section 2.5.1.4.2.2 refers to Section 2.5.1.4.2.3 “Fire Protection, Technical Evaluation, Results” for the fire protection assessment details.

Additional Information
LR Section 2.5.1.4.2.3.2, “Fire Protection, Results, Plant Design Features,” addresses portable, fixed fire suppression systems and detection. LR Section 2.5.1.4.2.3.1, “Fire Protection, Results, Administration,” addresses fire protection responsibilities of plant personnel. LR Section 2.5.1.4.2.3.7, “Fire Protection, Results, Operator Actions Required Following a Fire,” addresses procedures and resources for the repair of systems required to achieve and maintain cold shutdown.

LR Section 2.5.1.4.2.3.8, “Fire Protection, Results, Other Supporting Analysis/Evaluations,” subsection “Risk/Potential for Radiological Release Due to a Fire,” states that ‘there is no significant increase in the potential for a radiological release from a fire at SPU conditions.

The statement that SPU has no impact upon the design and operation of fire barriers is missing from LR Section 2.5.1.4.2.3.2, “Fire Protection, Results, Fire Protection, Plant Design Features,” of Section 2.5.1.4.2.3.3, “Fire Protection, Results, Fire Analysis”. This RAI response provides a clear statement that SPU has no impact upon fire barriers installed to satisfy NRC fire protection requirements.

The licensee’s response satisfactorily addresses the NRC staff’s concerns, and this RAI issue is considered resolved based on the following: the proposed SPU would not revise FPP elements, i.e., fire suppression and detection system, fire barriers, responsibilities of plant personnel, and resources for the repair of systems required to achieve and maintain cold shutdown. The

licensee indicated that for the proposed SPU condition, there is no significant increase in the potential for a radiological release resulting from a fire.

In RAI AFPB-07-0007 from letter dated November 26, 2007,[76] the NRC staff noted that LAR Attachment 5, Section 2.5.1.4.2.3.4, "Safe Shutdown Evaluations," states that "…the safe-shutdown analysis identifies fire-induced failures that affect the plant and the operator actions that can be used to compensate for these failures..."

The staff requested that the licensee discuss the response time, including any assumptions, especially those of a potentially non-conservative nature, which may have been made in determining that the operator manual actions can confidently be accomplished within the available time. By letter dated February 25, 2008 (ML080560615), the licensee provided the following response:

> As described in LAR Section 2.5.1.4.2.3.4, the revised analyses performed at SPU conditions for both Control Room Fire Transient and Charging Cubicle Fire Transient confirms that SPU does not impact the required operator action times.
>
> The assumptions for critical operator actions used in pre-SPU and post-SPU analyses remain the same for the Control Room Fire Transient. The critical operator actions assumed following the reactor trip from the control room and initiation of main steam isolation (MSI) signal from the control room are letdown isolation and charging flow restoration. Specifically, the analysis assumes 15 minutes for letdown isolation and 30 minutes for the restoration of charging flow from the event initiation. The response times for these assumed action times have been validated for current power levels and are well within the assumed operator action times. These response times are not impacted for post SPU conditions.
>
> Note that the response time for the manual initiation of auxiliary feedwater is discussed in AFPB-07-0008. Operator initiation time of auxiliary feedwater flow is not a parameter used in the above stated analysis.
>
> The current analysis for the Charging Cubicle Fire Transient was performed using the TREAT model. There are several operator actions that occur at specific times throughout the transient that are critical in maintaining pressurizer level on scale. Specifically, the current analysis assumes letdown isolation in 5 minutes, reactor trip in 10 minutes, closure of the MSI valves (MSIVs) in 11 minutes and securing the pressurizer heaters in 15 minutes. The revised analysis for SPU conditions was performed using the NOTRUMP model. The assumed critical operator action times remain the same as the pre-SPU conditions. It is noted that the SPU analysis assumed 695 seconds (11.6 minutes) for MSIV closure. This provides a small increase in margin for operator action that is unrelated to SPU. These analysis assumptions are bounding with respect to the fire shutdown procedure of record.

[76] ADAMS Accession No. ML073170665

The licensee's response satisfactorily addresses the NRC staff's concerns, and this RAI issue is considered resolved because for the SPU condition, the licensee updated the fire safe-shutdown analysis. The licensee indicated that the proposed power uprate does not impact the previous operator manual action time in the fire safe-shutdown analysis. The revised analysis results demonstrate that, at SPU condition, operator manual action times do not impact the CR fire transient or charging cubicle fire transient scenario. There are several operator manual actions that occur during the charging cubical fire scenario. Throughout this scenario, all operator manual action time remain the same except for the closure time of MSIVs. The MSIVs operator manual action closure time increases slightly from 11 minutes to 11 minutes and 35 seconds in the revised analysis. This increase does not have an impact on maintaining the pressurizer level on scale for the post-SPU condition.

In RAI AFPB-07-0008 from letter dated November 26, 2007,[77] the NRC staff noted that LAR Attachment 5, Section 2.5.1.4.2.3.7, "Operator Actions Required Following a Fire," states that "…[an] analysis was performed to determine the SG dryout time at the support SPU power level; the results showed a dryout time of approximately 37 minutes. Therefore, there continues to be adequate time for the operator to manually initiate AFW to the SGs at SPU conditions..."

The staff requested that the licensee discuss the response time, including any assumptions that may have been made in determining that the operator manual actions can confidently be accomplished before SG dryout. By letter dated February 25, 2008,[78] the licensee provided results of the updated CR fire scenario. The following response was provided in the licensee's letter:

> A thermal hydraulic analysis has been performed for the fire shutdown scenario[s] requiring control room evacuation (i.e., CB-8, CB-9, CB-11A/B fires), which assumes a delayed AFW initiation time of 31.5 minutes (30 minutes plus 90 seconds turbine driven AFW pump start time) to a minimum of two SGs. As stated in DNC initial response, the operator action to initiate AFW flow from [the] auxiliary shutdown panel to at least two SGs has been estimated to occur in approximately 27 minutes for the limiting fire scenario based upon current fire safe-shutdown procedures. In order to provide margin, this AFW initiation time will be reduced to less than 21.5 minutes (20 minutes plus 90 second turbine driven AFW pump start time) prior to implementation of the SPU, by making changes to the fire shutdown procedure and design compliance report.
>
> The analysis shows that the level in the two SGs begins to recover immediately after receiving AFW flow at 31.5 minutes. Secondary steaming shifts preferentially to the two SGs not receiving AFW flow. Inventory in the two SGs not receiving AFW flow continues to decrease until dryout in the range of 45 minutes.
>
> Even though the analysis conservatively assumes no AFW flow to two of the SGs because of the closure of two of the AFW control valves due to potential hot shorts, the current fire shutdown design/procedure calls for de-energizing the AFW solenoid operated control valves causing them to fail open. This action will occur before the 45-minute dryout time. Thus, completing this action within 45 minutes

[77] ADAMS Accession No. ML073170665
[78] ADAMS Accession No. ML080560615

will assure none of the SGs will dryout. The minimum AFW flow rate and operator action time assumed in the analysis are sufficient to remove decay heat and prevent SG dryout.

The licensee indicated that the CR evacuation scenario assumes a delayed AFW initiation time of 31.5 minutes. In the current fire shutdown procedure, the operator action to initiate AFW flow from the auxiliary shutdown panel to at least two SGs is 27 minutes. The licensee also stated that in order to provide margin, the AFW initiation time will be reduced to less than 21.5 minutes prior to implementation of the SPU by making changes to the fire shutdown procedure and design compliance report. The analysis shows that the level in the two SGs begins to recover immediately after receiving AFW flow at 31.5 minutes. As a result, the secondary steaming shifts to the other two SGs not receiving AFW flow that will experience dryout in the range of 45 minutes. This assumption is based on the closure of the AFW control valves due to potential hot shorts. However, the current fire shutdown design/procedures calls for de-energizing the AFW solenoid operated control valves causing them to fail open. This operator action will occur before the 45-minute dryout time for the two SGs. Completing this action within 45 minutes will assure none of the SGs will dryout at SPU power level.

The staff reviewed the proposed SPU for potential effects on operator manual action time and adequacy of the licensee's time for the operator to manually initiate AFW to the SGs at SPU conditions. The current difference between delayed AFW initiation time of 31.5 minutes and 27 minutes of operator action to initiate AFW flow from the auxiliary shutdown panel is 4.5 minutes. Prior to implementation of the SPU, the licensee will revise the AFW initiation time to 21.5 minutes, resulting in a greater margin of 10 minutes. Based on its review, the NRC staff concludes that the revised CR evacuation scenario is acceptable for SPU conditions.

In RAI AFPB-07-0009 from letter dated November 26, 2007,[79] the NRC staff noted that LAR Attachment 5, Table 2.5.1.4-1, "Fire Shutdown and Long-Term SG Inventory Makeup Required to Support the Decay Heat Removal Design Function BTP 9.5-1 Deviation Request - Section c.5.c.3 and c.5.c.5," states that, " …the current fire shutdown design 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-hour cooldown to RHR entry conditions (38 + 5 = 43-hours)…"

The licensee proposed an alternative fire shutdown design approach for long-term decay heat removal to SPU after reactor trip. This is based on the DWST's 334,000 gallons of water corresponding to 13 hours of SG inventory makeup under natural circulation conditions with decay heat load after SPU, and the CST's 210,000 gallons of additional SG makeup. This combined DWST and CST inventory provides 33 hours of makeup water with decay heat load after SPU.

It was not clear whether the reported 43 hours represents the current (i.e., pre-SPU) requirement for long-term HOT STANDBY operation plus cooldown or the capacity available for this combination. If the latter, then the staff noted a significant reduction in the amount of time (10 hours) in the proposed fire shutdown long-term decay heat removal approach to support SPU condition after reactor trip. If this was the case, then the NRC staff requested the licensee to discuss the impact of this reduction in time on the post-fire safe-shutdown capability.

[79] ADAMS Accession No. ML073170665

On the other hand (i.e., if the former), then it followed that a shorter time (i.e., less than 33 hours) is currently needed to accomplish long-term HOT STANDBY and cooldown (i.e., pre-SPU). Therefore an increase from this current time requirement to the 33-hours value was proposed, decreasing the margin of reserve (i.e., relative to the cited 43-hour combined capacity of the DWST and CST) under SPU. The reason for this decrease in margin, as well as the impact, would need to be discussed. The staff requested that the licensee discuss if, indeed, this was the implication of the alternative approach.

By letter dated December 17, 2007, the licensee provided following response. Note that the staff evaluation in this SE is based on the purely deterministic basis, not on risk-informed insights.

1. General
   Due to increased decay heat, SPU causes a 9% reduction in the available steaming time for the combined Demineralized Water Storage Tank (DWST) and Condensate Storage Tank (CST) inventory.

2. Current Fire Shutdown Design, Inventory for Sensible and Decay Heat Removal

   The current fire shutdown design is described in the MPS3 BTP 9.5-1 Compliance Report. The RCS decay heat removal design function is supported by the following AFW pump(s) suction sources:

Table 1
Existing Fire Shutdown Design

AFW Pump Suction Source	Approximate Equivalent Steaming (Hours)
DWST and CST	43 (38+5)*
Service Water System	Unlimited

* 38 hours at HOT STANDBY, followed by a 5-hour cooldown to RHR entry condition (38/5)

   In summary, 43 hours (i.e., 38/5) represents the DWST & CST available capacity based upon an historic engineering assessment circa 1985.

3. Proposed Fire Shutdown Design, Inventory for Sensible and Decay Heat Removal

   In the proposed fire shutdown design, DNC is not crediting service water (seawater) as an AFW pump suction source. Table 2 depicts the proposed fire shutdown design:

Table 2
Proposed Fire Shutdown Design

AFW Pump Suction Source	Approximate Equivalent Steaming (Hours)
DWST and CST	33-hours
Other non-seawater DWST or CST refill options (defense-in-depth/risk informed insight design approach)	19-hours (~150,000-gallons)

For MPS3 fire shutdown events, an AFW pump suction source isn't required once a Residual Heat Removal (RHR) System train is placed in-service.

The SPU assessment of the maximum RHR entry time for a fire shutdown event identified only two fire scenarios that have RHR entry time beyond 33-hours. These fire shutdown scenarios are the AB-1 north fire (this scenario involves a Reactor Plant Component Cooling Water System Pump repair evolution) and the AB-1 south fire (this scenario involves a loss of all charging event and a boration evolution using the RWST and safety injection pumps). These two fire scenarios have a[n] RHR entry time ≤ 52-hours.

The DWST/CST combined inventory equivalent steaming time has decreased from 43 hours (38/5) to 33 hours (28/5) which is a 10-hour reduction (or a 25% reduction). There is a 9% steaming time reduction (4 hours) due to increased SPU decay heat. The remaining steaming time reduction is due to an increase in the CST & DWST unusable inventory allowances and a more conservative initial CST inventory assumption.

Specifically, a 50,000-gallon CST unusable volume allowance is used; consistent with the technical bases technical specification 4.7.1.3.2, "Demineralized Water Storage Tank." A 50,000-gallon condensate volume corresponds to approximately 6 hours of additional steaming time. The SPU assessment also uses a 20,000-gallon unusable DWST inventory allowance, consistent with calculations that support the technical bases for technical specification 3.7.1.3. The 50,000-galion CST and 20,000-gallon DWST unusable volume allowances are much larger than assumed in the current fire shutdown design. In addition, an initial measured CST inventory of ~ 210,000 gallons was used, which is conservative relative to normal CST inventory levels.

4. Impact Upon Fire Shutdown Capability

There is no adverse impact upon fire shutdown capability based upon risk informed insights because 33-hours after reactor shutdown provides ample time for DWST/CST replenishment from the available options.

> The SPU licensing submittal Table 2.5.1.4-1 "Justification" Section states: "The proposed fire shutdown change 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".
>
> The SPU licensing submittal Attachment 1 (pages 26 & 27 and pages 51 & 52) also repeats the above justification. The Risk Evaluation Section (Page 2.13-64) addresses AFW pump suction source long-term replenishment evolutions and concludes operator action time window for tank replenishment activities has not changed enough to cause a significant change in the reliability of secondary cooling design function. Section 2.13.2.3.1, "Fire Risk," contains a statement that SPU has a negligible impact on the mitigation of fires and resulting core damage frequency (CDF) due to a loss of safety functions.
>
> Given the diverse DWST & CST refill options available (some of which are identified in Table 2.5.1.4-1), there is little risk that plant operators would fail to replenish the DWST/CST, if additional SG steaming was required beyond 33 hours.

The licensee's response satisfactorily addresses the NRC staff's concerns, and this RAI issue is considered resolved because the licensee indicated that, at SPU conditions, the increase in decay heat by 9-percent (4 hours) reduces the steaming time for the DWST and CST inventory. The remaining steaming time reduction, i.e., 6 hours, is due to an increase in the DWST and CST unusable inventory allowances. Currently, the licensee has credited on-site sources of AFW for safe-shutdown following a fire (DWST and CST) and service water (seawater). However, based on the deleterious effects of using service water in SGs, the licensee proposed that service water will not be credited as the means of replenishing AFW for safe-shutdown following a fire at SPU conditions (service water is not credited in the fire safe-shutdown analysis). The licensee indicated that the service water will be used only as an option of last resort.

The MPS3 current license basis is 38 hours of HOT STANDBY operation, followed by a 5 hour cooldown to RHR entry conditions, (i.e., a total of 43 hours after reactor trip). In addition, service water is credited in the current fire safe-shutdown analysis.

The licensee proposed an alternative fire safe-shutdown approach for the long-term SG inventory based on combined DWST and CST volume. The revised analysis shows that the combined DWST and CST volume is sufficient to maintain the reactor at HOT STANDBY conditions for 28 hours, followed by a 5-hour cooldown to RHR entry conditions, (i.e., a total of 33 hours after reactor trip). Further, other non-seawater DWST or CST refill options are available for 19 hours for inventory makeup based upon the defense-in-depth design feature, i.e., 150,000 gallons of DWST and CST inventory is available for refill. The licensee indicated that a portable diesel driven pump is available for DWST and CST refill and is associated with the Section B.5.b to Interim Compensatory Measures Order. The security event diesel driven pump capacity is significantly greater than required for the fire shutdown event.

The NRC staff concluded that the alternative fire safe-shutdown approach for the long-term SG inventory based on combined DWST and CST volume for total of 33 hours after reactor trip and 19 hours for inventory makeup is acceptable solely based on a deterministic basis, i.e., defense-in-depth approach. Further, the licensee indicated that the service water will be used only as an option of last resort. The staff concluded that maintaining service water capability is also a defense-in-depth approach.

Conclusion

The NRC staff has reviewed the licensee's fire-related safe shutdown assessment and concludes that the licensee has adequately accounted for the effects of the increased decay heat on the ability of the required systems to achieve and maintain safe shutdown conditions. The NRC staff further concludes that the FPP will continue to meet the requirements of 10 CFR 50.48, Appendix R to 10 CFR Part 50, and GDCs 3 and 5 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to fire protection.

2.5.2 Pressurizer Relief Tank

Regulatory Evaluation

The pressurizer relief tank (PRT) is a pressure vessel provided to condense and cool the discharge from the pressurizer safety and relief valves. The tank is designed with a capacity to absorb discharge fluid from the pressurizer relief valve during a specified step-load decrease. The PRT system is not safety-related and is not designed to accept a continuous discharge from the pressurizer. The NRC staff conducted a review of the PRT to ensure that operation of the tank is consistent with transient analyses of related systems at the proposed SPU level, and that failure or malfunction of the PRT system will not adversely affect safety-related SSCs. The NRC staff's review focused on any design changes related to the PRT and connected piping, and changes related to operational assumptions that are necessary in support of the proposed SPU that are not bounded by previous analyses. In general, the steam condensing capacity of the tank and the tank rupture disk relief capacity should be adequate, taking into consideration the capacity of the pressurizer power-operated relief and safety valves; the piping to the tank should be adequately sized; and systems inside containment should be adequately protected from the effects of HELBs and moderate-energy line cracks in the pressurizer relief system. The NRC's acceptance criteria for the PRT are based on: (1) GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes; and (2) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate and be compatible with specified environmental conditions, and be appropriately protected against dynamic effects, including the effects of missiles. Specific review criteria are contained in SRP Section 5.4.11.

Technical Evaluation

The pressurizer safety valves (PSV) and pressurizer power-operated relief valves (PORVs) discharge reactor coolant to the PRT through a submerged sparger pipe. The tank is equipped with an internal spray and a drain that are used to cool the water following a discharge. The PRT is constructed of austenitic stainless steel and is overpressure protected in accordance with ASME Code, Section VIII, Division 1, by two safety heads with stainless steel rupture discs.

The PRT tank is sized to condense and cool steam discharges equal to 110 percent of the full power pressurizer steam volume following the worst-case loss of external electrical load transient without reactor trip. The loss of external electrical load transient analysis performed by MPS3 indicated that the pressurizer steam mass and energy (M&E) discharged into the PRT would be less than the design bases discharge; therefore, the PRT design remains conservative.

The PRT high and low level alarm setpoints ensure adequate coolant is maintained in the tank in order to condense and cool the design bases discharge and prevent the PRT temperature and pressure from exceeding the design limits of 200 °F and 50 psig, respectively. The loss of external electrical load analysis resulted in a change to the pressurizer level program band upper value from 61 percent to 64 percent, requiring a new PRT level alarm setpoint for the PRT to accept 110 percent of the pressurizer steam space discharge at the SPU pressurizer level. The revised PRT high and low level alarm setpoints were adjusted at 84-percent and 56-percent, respectively.

Conclusion

The NRC staff has reviewed the increase in pressurizer discharge to the PRT as a result of the proposed SPU and concludes that: (1) the PRT will operate in a manner consistent with transient analyses of related systems; and (2) safety-related SSCs will continue to be protected against failure of the PRT consistent with GDCs 2 and 4. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the design of the PRT.

2.5.3 Fission Product Control

2.5.3.1 Fission Product Control Systems and Structures

Regulatory Evaluation

The NRC staff's review for fission product control systems and structures covered the basis for developing the mathematical model for DBLOCA dose computations, the values of key parameters, the applicability of important modeling assumptions, and the functional capability of ventilation systems used to control fission product releases. The NRC staff's review primarily focused on any adverse effects that the proposed SPU may have on the assumptions used in the analyses for control of fission products. The NRC's acceptance criteria are based on GDC-41, insofar as it requires that the containment atmosphere cleanup system be provided to reduce the concentration of fission products released to the environment following postulated accidents. Specific review criteria are contained in SRP Section 6.5.3.

Technical Evaluation

The purpose of the NRC staff's review of fission product control systems and structures is to confirm that current analyses remain valid or have been revised, as appropriate, to properly reflect the proposed SPU conditions. Consequently, the NRC staff's review focuses primarily on any adverse effects that the proposed SPU might have on the assumptions that were previously used in the analyses. The impact of SPU on plant systems and structures identified by the licensee as making up the fission product control system are addressed in this SE in Section

2.6, “Containment Review Considerations,” Section 2.7, “Habitability, Filtration, and Ventilation,” and Section 2.9, “Source Terms and Radiological Consequences Analyses.”

Conclusion

The NRC staff has reviewed the licensee’s assessment of the effects of the proposed SPU on fission product control systems and structures. The NRC staff concludes that the licensee has adequately accounted for the increase in fission products and changes in expected environmental conditions that would result from the proposed SPU. The NRC staff further concludes that the fission product control systems and structures will continue to provide adequate fission product removal in post-accident environments following implementation of the proposed SPU. Based on this, the NRC staff also concludes that the fission product control systems and structures will continue to meet the requirements of GDC 41. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the fission product control systems and structures.

2.5.3.2 Main Condenser Evacuation System

Regulatory Evaluation

The main condenser evacuation system (MCES) generally consists of two subsystems: (1) the "hogging" or startup system which initially establishes MC vacuum; and (2) the system which maintains condenser vacuum once it has been established. The NRC staff’s review focused on modifications to the system that may affect gaseous radioactive material handling and release assumptions, and design features to preclude the possibility of an explosion (if the potential for explosive mixtures exists). The NRC’s acceptance criteria for the MCES are based on GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 10.4.2.

Technical Evaluation

The MCES is not impacted by the proposed power uprate because the condenser air removal requirements during startup are not affected. The MCES is sized based on the volume of the condenser and desired evacuation time, neither of which is impacted by the proposed power uprate. Consequently, the NRC staff finds the existing capability to monitor the MCES effluent is also not affected by the proposed SPU and therefore, is acceptable.

Conclusion

The NRC staff concludes that the MCES will continue meet the requirement of GDC 60. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the MCES.

2.5.3.3 Turbine Gland Sealing System

Regulatory Evaluation

The turbine gland sealing system is provided to control the release of radioactive material from steam in the turbine to the environment. The NRC staff reviewed changes to the turbine gland sealing system (TGSS) with respect to factors that may affect gaseous radioactive material

handling (e.g., source of sealing steam, system interfaces, and potential leakage paths). Specific review criteria are contained in SRP Section 10.4.3.

Technical Evaluation

The TGSS is designed to provide sealing steam for the TG shaft and to prevent leakage of air into the turbine casing and the escape of steam into the turbine building, thereby preventing the uncontrolled release of radioactive material from steam in the turbine to the environment. No physical changes to systems components or changes in system operation are required due to the slight increase in sealing flow and gland steam condenser cooling flow. There is no radiation monitoring at the gland seal condenser vent, as radioactive releases fall within the total unmonitored steam release specifications from the TB as defined in NUREG-0017, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors," dated April 1976. The staff finds the function of the TGSS will not be impacted by the proposed power uprate and is acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of required analyses of the TGSS and concludes that the licensee has adequately evaluated the system. The NRC staff concludes that the TGSS will continue to maintain its function. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the TGSS.

2.5.4 Component Cooling and Decay Heat Removal

2.5.4.1 Spent Fuel Pool Cooling and Cleanup System

Regulatory Evaluation

The SFP provides wet storage of spent fuel assemblies. The safety function of the spent fuel pool cooling and cleanup system (SFPCCS) is to cool the spent fuel assemblies and keep the spent fuel assemblies covered with water during all storage conditions. The NRC staff's review for the proposed SPU focused on the effects of the proposed SPU on the capability of the system to provide adequate cooling to the spent fuel during all operating and accident conditions. The NRC's acceptance criteria for the SFPCCS are based on: (1) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; (2) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided; and (3) GDC 61, insofar as it requires that fuel storage systems be designed with RHR capability reflecting the importance to safety of decay heat removal, and measures to prevent a significant loss of fuel storage coolant inventory under accident conditions. Specific review criteria are contained in SRP Section 9.1.3, as supplemented by the guidance provided in Attachment 1 to Matrix 5 of Section 2.1 of RS-001.

Technical Evaluation

In Section 2.5.4.1 of the MSP3 LAR, the licensee evaluated the impact the SPU would have on the capability of the SFPCCS to continue to provide adequate cooling. Although the SPU would

result in a slight increase in heat load, the licensee indicated that the current analysis of record demonstrates that the MPS3 SFP cooling system heat removal capability is sufficient to maintain the required SFP temperature. The existing analysis of record is still bounding for the SPU conditions. The decay heat load for an emergency full core offload is bounded by the decay heat load for a normal full core offload and further review is not necessary. The SPU also has no impact on the hydraulic portions of the purification subsystem and the current purification flow rate is adequate for SPU conditions. Any increase in fission products resulting from the increased equilibrium RCS radioactivity is mitigated by the RCS cleanup systems prior to fuel assembly transfer to the SFP. Thus, no equipment changes in the purification loop are required to support the power uprate.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the SFPCCS and concludes that the licensee has adequately accounted for the effects of the proposed SPU on the SFP cooling function of the system. Based on this review, the NRC staff concludes that the SFPCCS will continue to provide sufficient cooling capability to cool the SFP following implementation of the proposed SPU and will continue to meet the requirements of GDCs 5, 44, and 61. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the SFPCCS.

2.5.4.2 Station Service Water System

Regulatory Evaluation

The station service water system (SWS) provides essential cooling to safety-related equipment and may also provide cooling to non-safety-related auxiliary components that are used for normal plant operation. The NRC staff's review covered the characteristics of the station SWS components with respect to their functional performance as affected by adverse operational (i.e., water hammer) conditions, abnormal operational conditions, and accident conditions (e.g., a LOCA with the LOOP). The NRC staff's review focused on the additional heat load that would result from the proposed SPU. The NRC's acceptance criteria are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, including flow instabilities and loads (e.g., water hammer), maintenance, testing, and postulated accidents; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided. Specific review criteria are contained in SRP Section 9.2.1, as supplemented by GL 89-13[80] and GL 96-06.[81]

Technical Evaluation

In Section 2.5.4.2 of the MPS3 LAR, the licensee discussed the impact the SPU would have on the capability of SWS to continue to provide essential cooling water to the various plant

[80] Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," dated July 18, 1989.
[81] Generic Letter 96-06, "Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions," dated September 20, 1996.

components as a result of SPU. The licensee indicated that although the SPU would slightly increase the amount of heat rejected to the SWS, system design limitations would not be exceeded. The higher heat loads for the CCW heat exchangers during certain SPU operations (e.g., plant cooldown) would result in higher SWS outlet temperatures. However, the increase in SWS outlet temperature is still within the plant's allowable discharge limit. In addition, existing programmatic controls established in response to GL 89-13 remain in place and continue to assure that heat exchanger performance is consistent with design-basis assumptions.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed SPU on the station SWS and concludes that the licensee has adequately accounted for the increased heat loads on system performance that would result from the proposed SPU. The NRC staff concludes that the station SWS will continue to provide sufficient cooling for SSCs important to safety following implementation of the proposed SPU. Therefore, the NRC staff has determined that the station SWS will continue to meet the requirements of GDCs 4, 5, and 44. Based on the above, the NRC staff finds the proposed SPU acceptable with respect to the station SWS.

2.5.4.3 Reactor Auxiliary Cooling Water Systems

Regulatory Evaluation

The NRC staff's review covered reactor auxiliary cooling water systems that are required for: (1) safe shutdown during normal operations, AOOs, and mitigating the consequences of accident conditions; or (2) preventing the occurrence of an accident. These systems include closed-loop auxiliary cooling water systems for reactor system components, reactor shutdown equipment, ventilation equipment, and components of the ECCS. The NRC staff's review covered the capability of the auxiliary cooling water systems to provide adequate cooling water to safety-related ECCS components and reactor auxiliary equipment for all planned operating conditions. Emphasis was placed on the cooling water systems for safety-related components (e.g., ECCS equipment, ventilation equipment, and reactor shutdown equipment). The NRC staff's review focused on the additional heat load that would result from the proposed SPU. The NRC's acceptance criteria for the reactor auxiliary cooling water system are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation including flow instabilities and attendant loads (i.e., water hammer), maintenance, testing, and postulated accidents; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided. Specific review criteria are contained in SRP Section 9.2.2, as supplemented by GL 89-13 and GL 96-06.

Technical Evaluation

One effect of the SPU is the removal of higher heat loads that result in higher temperatures downstream of those supplied components. The NRC staff's review covers reactor auxiliary cooling water systems that are required for safe shutdown during normal operations, AOOs, and mitigating the consequences of accident conditions, or preventing the occurrence of an accident. Emphasis was placed on the cooling water systems for safety-related components (e.g., ECCS equipment, ventilation equipment, and reactor shutdown equipment).

In Section 2.5.4.3 of the MPS3 LAR, the license stated that a design change was required to increase the design temperature rating of the CCW system piping and components between the RHR heat exchangers and the CCW heat exchangers to 160 °F from 150 °F, and increase the CCW system operating temperature during cooldown MODES of operation. The NRC asked the licensee to provide a description of the change, the impact on system components, and any modifications that would be required to support the change. In a letter dated January 18, 2008, the licensee stated that a normal and safety grade cooldown can be accomplished by maintaining CCW water temperature out of the RHR heat exchangers to 145 °F, which is less than the current analyzed stress limit of 150 °F. Therefore, the CCW system can operate under the current design rating at SPU conditions. The licensee is continuing with the design change to uprate CCW piping and components to 160 °F in order to achieve sufficient margin between design and operating temperature limits. The evaluation of CCW piping and component stresses under SPU condition is discussed in Section 2.2.2 of this report.

The licensee evaluated CCW flow rates to supplied components and total CCW system flow at SPU conditions and determined that they do not affect the ability of the CCW system to perform the intended functions, nor exacerbate FIV in heat exchangers. There are no new operating MODES or system pumping/valve-position lineups required as a result of SPU. The CCW system relief valves either have no change or small changes in temperatures that are bounded by the relief valve design.

The operating band of the CCW surge tank is sufficient to accept the increase in system thermal expansion volume relative to the current system volume. This increase is bounded by the volume calculated between the upper limit of the operating band and high level alarm. The free volume above the upper limit exceeds the volume required for the thermal expansion increase. The licensee concluded that the existing CCW system and components will continue to operate successfully to supply sufficient flow to cool components and to remove the heat loads at SPU conditions, including support of existing fire safe shutdown licensing basis requirements. Based on the design of the CCW system, the staff confirmed that adequate margin is provided to accommodate the thermal expansion at SPU operation.

The licensee also evaluated the chilled water system (CDS), neutron shield tank cooling system, charging pumps cooling system (CCE), and safety injection pumps cooling system (CCI) performance to assure compliance with Generic Letters 89-13 and 96-06 with regard to service water fouling in heat exchangers, heatup and over pressurization of isolated portions of piping inside containment, and boiling or water hammer in service water cooling lines to the containment atmosphere recirculation coolers and indicated that these systems and components will continue to operate successfully to supply sufficient flow to cool components and to remove the heat loads at SPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the reactor auxiliary cooling water systems and concludes that the licensee has adequately accounted for the increased heat loads from the proposed SPU on system performance. The NRC staff concludes that the reactor auxiliary cooling water systems will continue to be protected from the dynamic effects associated with flow instabilities and provide sufficient cooling for SSCs important to safety following implementation of the proposed SPU. Therefore, the NRC staff has determined that the reactor auxiliary cooling water systems will continue to meet the requirements of GDCs 4, 5, and 44. Based on the above, the NRC staff finds the proposed SPU acceptable with respect to the reactor auxiliary cooling water systems.

2.5.4.4 Ultimate Heat Sink

Regulatory Evaluation

The ultimate heat sink (UHS) is the source of cooling water provided to dissipate reactor decay heat and essential cooling system heat loads after a normal reactor shutdown or a shutdown following an accident. The NRC staff's review focused on the impact that the proposed SPU has on the decay heat removal capability of the UHS. Additionally, the NRC staff's review included evaluation of the design-basis UHS temperature limit determination to confirm that post-licensing data trends (e.g., air and water temperatures, humidity, wind speed, water volume) do not establish more severe conditions than previously assumed. The NRC's acceptance criteria for the UHS are based on: (1) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety; and (2) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided. Specific review criteria are contained in SRP Section 9.2.5.

Technical Evaluation

The licensee's evaluation of the impact the SPU will have on the capability of the UHS to accept heat from SW systems during plant operation, plant cooldown, and post accident conditions is provided in MSP3 LAR, Section 2.5.4.4. Acceptable performance of the UHS is based on the ability to maintain an acceptable inventory of water to accept the design basis heat load at SPU conditions under limiting conditions. Long Island Sound is effectively an infinite heat sink. The NRC staff confirmed the licensee's evaluation through the review of rejected heat loads from plant component cooling systems that are still with the design parameters.

Conclusion

The NRC staff has reviewed the information that was provided by the licensee for addressing the effects that the proposed SPU would have on the UHS safety function, including the licensee's validation of the design-basis UHS temperature limit based on post-licensing data. Based on the information that was provided, the NRC staff concludes that the proposed SPU will not compromise the design-basis safety function of the UHS, and also concludes that the UHS will continue to satisfy the requirements of GDCs 5 and 44 following implementation of the

proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the UHS.

2.5.4.5 Auxiliary Feedwater System

Regulatory Evaluation

In conjunction with a seismic Category I water source, the AFW system (AFWS) functions as an emergency system for the removal of heat from the primary system when the main feedwater system is not available. The AFWS may also be used to provide decay heat removal necessary for withstanding or coping with an SBO. The NRC staff's review for the proposed SPU focused on the system's continued ability to provide sufficient emergency feedwater flow at the expected conditions (e.g, SG pressure) to ensure adequate cooling with the increased decay heat. The NRC staff's review also considered the effects of the proposed SPU on the likelihood of creating fluid flow instabilities (e.g., water hammer) during normal plant operation, as well as during upset or accident conditions. The NRC's acceptance criteria for the AFWS are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; (3) GDC 19, insofar as it requires that equipment at appropriate locations outside the CR be provided with: (a) the capability for prompt hot shutdown of the reactor; and (b) a potential capability for subsequent cold shutdown of the reactor; (4) GDC 34, insofar as it requires that an RHR system be provided to transfer fission product decay heat and other residual heat from the reactor core, and that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure; and (5) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure. Specific review criteria are contained in SRP Section 10.4.9.

Technical Evaluation

The AFWS normally operates to support plant startup, HOT STANDBY and shutdown evolutions. The AFWS major components include two 50-percent capacity motor driven AFW pumps, one 100-percent capacity turbine driven AFW pump, and a DWST. Portions of the AFWS piping are classified as high energy lines in accordance with SRP Sections 3.6.1 and 3.6.2.

The primary impact on the AFWS as a result of SPU is the resulting larger heat removal requirement during design basis events/accidents, normal cooldown, and safety grade cold shutdown. The larger heat removal requirements will not change the maximum system operating conditions. Thus, the design margins for AFW system piping and components design remain essentially the same. There are no expected changes to the minimum or maximum available flow rates at SPU conditions. As a result, the likelihood of fluid flow instabilities is not increased with SPU.

In Section 2.5.4.5 of the MSP3 LAR, the results of the licensee's safety analyses indicated that existing AFWS performance remains bounding at SPU conditions in terms of providing sufficient flow and pressure to mitigate the consequences of the design basis events. However, a licensing basis change for the DWST inventory is required to support SPU conditions in order to address the greater amount of removed decay heat. The current licensing basis requires that concurrent with a LOOP, sufficient water should be available to maintain the RCS at HOT STANDBY for 10 hours with steam discharge to the atmosphere, and an additional 6 hours cooldown period to reduce reactor coolant temperature to RHR system entry conditions.

The licensee proposed to reduce the requirement from 10 hours to 7 hours at HOT STANDBY condition. The actual physical size of the DWST would not be modified, nor the amount of water required in the DWST. TS 3.7.1.3 for the DWST will still require a minimum of 334,000 gallons, corresponding to 13 hours of SG inventory makeup under natural circulation conditions with the decay heat load at SPU conditions. The licensee's analysis determined that only 172,858 gallons of DWST inventory is required for decay heat removal and plant cooldown for an SBO event at SPU conditions, as compared with TS minimum requirement of 334,000 gallons of water in the DWST required for decay heat removal and plant cooldown for an 8-hour SBO event at SPU conditions. The staff asked that the licensee provide an evaluation of the proposed licensing basis change from 10 hours to 7 hours. In letter dated January 11, 2008, the licensee stated that the 10-hour requirement originated from a prior assessment to meet draft Regulatory Guide (RG) 1.139, "Guidance for Residual Heat Removal,"[82] commitments. Subsequently, NRC BTP RSB 5-1[83] was issued in lieu of RG 1.139. BTP RSB 5-1 provides guidance to comply with GDC 19 and GDC 34 with regard to functional capability for the reactor to be taken from normal operating conditions to cold shutdown using only safety grade systems. BTP RSB 5-1 states the seismic Category I-1 water supply for the AFWS for a PWR shall have sufficient inventory to permit operation at hot shutdown for at least four hours, followed by cooldown to the conditions permitting operation of the RHR system.

The MPS3 UFSAR Section 10.4.9 states "The DWST is also designed to provide sufficient water for safety grade cold shutdown in accordance with BTP RSB 5-1." Upon a loss of normal feedwater (LONF), the licensee's proposed 7-hours at hot standby with higher decay heat as a result of SPU does not impact the available water volume in DWST to provide cooldown. The required volume of water in the DWST provides sufficient heat transfer from each SG to dissipate residual heat without losing inventory through lifted open pressurizer relief valves due to the pressurizer reaching water solid condition. The staff has confirmed that the required water inventory in DWST does not change and the TS requirement remains effective to ensure the makeup volume is available for decay heat removal and to mitigate an SBO event. The staff considers the licensee's proposed 7-hours at HOT STANDBY to satisfy the minimum requirement stated in BTP RSB 5-1.

The licensee also proposes to change the requirement for the DWST to have sufficient inventory to achieve safety grade cold shutdown in a reasonable time period from 66 to 72 hours, maintaining the same 36-hour requirement for entering RHR conditions. The basis for a reasonable time period stems from BTP RSB 5-1, which states that system(s) shall be capable of bringing the reactor to a cold shutdown condition, with only offsite or onsite power available, within a reasonable period of time following shutdown, assuming the most limiting single failure.

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[82] Draft Regulatory Guide 1.139, "Guidance for Residual Heat Removal," dated May 31, 1978.
[83] Branch Technical Position RSB 5-1, "Design Requirements of the Residual Heat Removal System," July 1981.

The NRC staff asked the licensee to explain how it would satisfy the 36-hour requirement using only safety-related equipment. In letter dated January 11, 2008, the licensee stated that the RHR entry time for SG cold shutdown (SGCS) is 11 hours and remains applicable upon implementation of SPU. The licensee also stated that there is no functional requirement derived from BTP RSB 5-1 guidance that would require MPS3 to have a 36-hour safety-related SG inventory makeup supply. The only requirement is to have sufficient safety-related SG make-up inventory to achieve cold shutdown in a reasonable time period. The only SG inventory make-up source credited in the MPS3 SPU SGCS analysis is the safety-related DWST. Thus, BTP RSB 5-1 Regulatory Positions A and G are satisfied by achieving RHR condition in the proposed 11 hours. The staff confirmed this information in BTP RSB 5-1 Regulatory Positions A and G.

The DWST inventory is also credited within the fire shutdown analysis. For a safe fire shutdown, Table 2.5.4.5-3 provides a comparison of functional requirements. The credited on-site sources of AFW for safe shutdown following a fire are the DWST and CST. Prior to the SPU, these two tanks provide a total of 43 hours of cooling water (38 hours at HOT STANDBY and 5 hours for cooldown to RHR conditions). Upon implementation of SPU, these tanks collectively will provide a total of 33 hours of cooling water (28 hours at HOT STANDBY and 5 hours for cooldown to RHR conditions). The licensee's analyses indicate that the time to cold shutdown following a fire at SPU conditions show that SG inventory makeup will be required beyond 33 hours because of higher decay heat level after reactor trip as a result of a fire. Additional sources of makeup water are discussed in Section 2.5.1.4 of this report.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the AFWS. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in decay heat and other changes in plant conditions on the ability of the AFWS to supply adequate water to the SGs to ensure adequate cooling of the core. The NRC staff finds that the AFWS will continue meet its design functions following implementation of the proposed SPU. The NRC staff further concludes that the AFWS will continue to meet the requirements of GDCs 4, 5, 19, 34, and 44. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the AFWS.

2.5.5 Balance-of-Plant Systems

2.5.5.1 Main Steam

Regulatory Evaluation

The main steam supply system (MSSS) transports steam from the NSSS to the power conversion system and various safety-related and non-safety-related auxiliaries. The NRC staff's review focused on the effects of the proposed SPU on the system's capability to transport steam to the power conversion system, provide heat sink capacity, supply steam to drive safety system pumps, and withstand adverse dynamic loads (e.g., water steam hammer resulting from rapid valve closure and relief valve fluid discharge loads). The NRC's acceptance criteria for the MSSS are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures; (2) GDC 5, insofar as it

requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC 34, insofar as it requires that an RHR system be provided to transfer fission product decay heat and other residual heat from the reactor core. Specific review criteria are contained in SRP Section 10.3.

Technical Evaluation

The proposed SPU would increase steam temperature of the reheat lines to 533 °F from 500 °F. As a result, the MSS design temperature of the hot reheat lines, to include the supply lines to the SG feedwater pump turbines, is required to be rerated to a higher temperature prior to implementation of the SPU; this will be performed during the fall 2008 refueling outage. The licensee's evaluation of these lines indicated that they would be acceptable for SPU operations based on the maximum allowable stress values of the piping materials. At SPU conditions, the flow velocities through the main steam increased approximately 8.5 percent. These flow velocities are bounded by the industry design guidelines. During power ascension following implementation of the proposed SPU, piping will be monitored to identify line vibration anomalies. The licensee's approach to monitoring vibration in piping is evaluated in Section 2.2 of this report.

The licensee stated that to preclude any problems with design capability and performance at SPU conditions, modifications were required for the feedwater pump turbines to provide required motive power and feedwater flow and pressure to SGs at SPU conditions. As a result, the entire turbine steam path, including the rotating assembly and the diaphragms, will be replaced. The licensee also stated that there is a potential for the control valve and/or seat modification to provide more steam flow to the turbine-driven feed pump steam control valves. The LAR also states that an engineering evaluation was needed to confirm whether more steam flow is required for turbine-driven feedwater pump turbine control valves for SPU conditions. The NRC staff asked the licensee to clarify whether a modification was necessary. In letter dated January 11, 2008, the licensee stated that no modifications to those valves would be required to support SPU conditions.

The current main steam (MS) safety valves pressures are based on the design pressure of the SG, MS piping, and the requirements of ASME III Boiler and Pressure Vessel (B&PV) Code. These design parameters are not changed by the proposed SPU. The results of licensee's analysis of the LOL/TT indicated that the primary and secondary pressure limits are met at the proposed SPU conditions. The maximum pressure in the primary system is 2729.4 psia verses a limit of 2750 psia and the maximum secondary system pressure is 1302.3 psia verses a limit of 1320 psia. No changes were needed to the primary or secondary relief or safety valves in order to meet the applicable pressure limits. Therefore, the existing pressures set for the MS safety valves are acceptable for SPU operation.

The MS safety valves were sized to pass 105 percent of the maximum calculated steam flow at an accumulation pressure not exceeding 110 percent of the MS system design pressure. At SPU conditions, the capacity of the installed MS safety valves satisfies the sizing criterion and overpressure protection requirements for the range of SPU NSSS design parameters.

The MS safety valves' design bases include a maximum flow limit of 970,000 lb/hr/valve at 1185 psig to preclude an uncontrolled plant cooldown and excessive reactivity excursion. These

valves are not changed by the proposed SPU. The actual capacity of any single MS safety valve will remain less than the maximum flow limit per valve.

The existing set pressure of the MS pressure relief valves is based on SG zero-load steam pressure and the set pressure of the lowest-set MS safety valve. At SPU conditions, these pressures are not changed. The MS pressure relief valves were sized to pass approximately 15-percent of rated MS flow at no-load pressure. The licensee's evaluation indicated that the total installed capacity supports plant cooldown capability for the range of NSSS design parameters at the proposed SPU and the existing bypass flow capability of main steam pressure relief bypass valve also satisfies the design basis functional requirements inherent in the UFSAR Chapter 15 safety analyses, the safety grade cold shutdown analysis, and the fire shutdown cooldown analysis.

The licensee indicated that the turbine control pressure instrumentation will be rescaled to accommodate increased flow rates and pressures in accordance with the plant design change process. The NRC staff asked the licensee to discuss the change in pressure and set point inputs from the high pressure turbine first stage to the reactor protection system (RPS). In a letter dated January 11, 2008, the licensee stated that a revised heat balance has been developed for MPS3 based upon the new 100 percent power level at SPU conditions. The heat balance using T_{avg} temperature of 587.1 °F predicted that a new turbine first stage pressure would be at approximately 712.2 psia for full load. As appropriate, the licensee indicated that the turbine first stage pressure transmitters will be rescaled from its present scaled full load value of 650 psia to a new scaled full load value of 715 psia. Because the transmitters will be rescaled to align with the new predicted full load, there will be no impact on any protection or control setpoints that use the transmitters input.

The licensee has proposed new TS limits for the main steam safety valves (MSSVs) at SPU conditions. In order to preclude secondary side overpressurization in the event of a loss-of-external-electrical-load or TT event, the maximum power level allowed for operation with inoperable MSSVs must be below the heat removing capability of the operable MSSVs. TS Table 3.7-1 would be revised to define the maximum allowed power level with an inoperable MSSVs. The Action Statements in TS 3.7.1.1 would also be revised to match the Improved Standard Technical Specifications. The staff considers implementation of the Action Statements will continue to provide assurance that the operating power level will be limited with inoperable MSSVs. An evaluation of the TS change is provided in Section 3.0 of this report.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the MSSS and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the MSSS. The NRC staff concludes that the MSSS will maintain its ability to transport steam to the power conversion system, provide heat sink capacity, supply steam to steam-driven safety pumps, and withstand steam hammer. The NRC staff further concludes that the MSSS will continue to meet the requirements of GDCs 4 and 5. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the MSSS.

2.5.5.2 Main Condenser

Regulatory Evaluation

The main condenser (MC) system is designed to condense and deaerate the exhaust steam from the main turbine and provide a heat sink for the turbine bypass system (TBS). The NRC staff's review focused on the effects of the proposed SPU on the steam bypass capability with respect to load rejection assumptions, and on the ability of the MC system to withstand the blowdown effects of steam from the TBS. The NRC's acceptance criteria for the MC system are based on GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 10.4.1.

Technical Evaluation

The MC system is designed to condense and de-aerate the exhaust steam from the main turbine and provide a heat sink for the TBS. The NRC staff's review focuses on the effects the proposed SPU will have on the control of radiological releases to the environment. For MPS3, the effect of the proposed SPU is negligible because leakage from the RCS through the SG the main steam is limited.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the MC system and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the MC system. The NRC staff concludes that the MC system will continue to maintain its ability to withstand the blowdown effects of the steam from the TBS and thereby continue to meet GDC 60 for prevention of the consequences of failures in the system. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the MC system.

2.5.5.3 Turbine Bypass

Regulatory Evaluation

The TBS is designed to discharge a stated percentage of rated main steam flow directly to the MC system, bypassing the turbine. This steam bypass enables the plant to take step load reductions up to the TBS capacity without the reactor or turbine tripping. The system is also used during startup and shutdown to control SG pressure. The NRC staff's review focused on the effects that SPU has on load rejection capability, analysis of postulated system piping failures, and on the consequences of inadvertent TBS operation. The NRC's acceptance criteria for the TBS are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be appropriately protected against dynamic effects, including the effects of missiles, pipe whipping, and discharging fluids that may result from equipment failures; and (2) GDC 34, insofar as it requires that an RHR system be provided to transfer fission product decay heat and other residual heat from the reactor core at a rate such that SAFDLs and the design conditions of the RCPB are not exceeded. Specific review criteria are contained in SRP Section 10.4.4.

Technical Evaluation

The licensee's analysis of a TT without reactor trip showed the pressurizer PORVs could be a potential problem at SPU conditions. A modification of the steam dump load rejection controller will include both the "Hi 1 and "Hi 2" setpoints. "Hi 1" will be changed from 6.6°F to 5.3°F. "Hi 2" will be changed from 15.8°F to 12.0°F for the option 1 coastdown. The modified setpoints would ensure that a TT would not result in a potential problem to the pressurizer relief valve lift setpoint. During a load runback transient, the MSS pressure would remain less thanthe MSSV setpoint.

The licensee modification to the definition of the load rejection transient will result in a ramp load change at a maximum rate of 200-percent-per-minute from a step change. This change in the definition from a step change to a ramp load change at a maximum rate of 200 percent-per-minute would redefine the load rejection in a more realistic manner, consistent with uprating projects previously performed on other Westinghouse plants.

The TBS at SPU operating pressure and temperature is bounded by the current system design pressure and temperature. The capability of the turbine bypass system to withstand adverse dynamic loads (e.g., steam hammer) resulting from turbine control valve fast closure or turbine stop valve closure for turbine protection at SPU conditions is evaluated in Section 2.3 of this report. Flow velocities in the TBS from the main steam manifold to the turbine bypass valves are bounded by the current design velocity criterion, except for the 26 inch line, where the velocity exceeds the original design velocity by six percent. The excess flow velocity at SPU conditions is evaluated in Section 2.2 of this report.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the TBS. The NRC staff concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the system. The NRC staff concludes that the TBS will continue to provide a means for shutting down the plant during normal operations. The NRC staff further concludes that TBS failures will not adversely affect essential systems or components. Based on this, the NRC staff concludes that the TBS will continue to meet GDCs 4 and 34. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the TBS.

2.5.5.4 Condensate and Feedwater

Regulatory Evaluation

The condensate and feedwater system (CFS) provides feedwater at the appropriate temperature, pressure, and flow rate to the SGs. The only part of the CFS classified as safety-related is the feedwater piping from the SGs up to and including the outermost containment isolation valve. The NRC staff's review focused on the effects of the proposed SPU on previous analyses and considerations with respect to the capability of the CFS to supply adequate feedwater during plant operation and shutdown, and to isolate components, subsystems, and piping in order to preserve the system's safety function. The NRC staff's review also considered the effects of the proposed SPU on the feedwater system, including the AFWS piping entering the SG, with regard to possible fluid flow instabilities (e.g., water hammer) during normal plant

operation, as well as during upset or accident conditions. The NRC's acceptance criteria for the CFS are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC 44, insofar as it requires that a system with the capability to transfer heat loads from safety-related SSCs to a heat sink under both normal operating and accident conditions be provided, and that suitable isolation be provided to assure that the system safety function can be accomplished, assuming a single failure. Specific review criteria are contained in SRP Section 10.4.7.

Technical Evaluation

The licensee evaluated the CFS at SPU conditions and determined that modification to the SG feedwater pump turbines would be required in order to provide the required motive power and feedwater flow and pressure to SGs at SPU conditions. As a result, the entire turbine steam path, including the rotating assembly and the diaphragms, will be replaced. Increasing the feedwater pump turbine speed to 5125 rpm will provide the required flow, net positive suction head (NPSH) to the pump suction and maintain the feedwater flow control valves at their pre-SPU position. This modification will require an increase in the setpoint, which controls feedwater turbine speed based upon differential pressure between the main steam and feedwater headers.

In Section 2.5.5.4 of the MSP3 LAR, the licensee stated that an engineering evaluation was required to confirm whether or not more steam flow is required for turbine driven feedwater pump for SPU conditions. The NRC staff asked the licensee to discuss any impacts or modifications. In a letter dated January 11, 2008, the licensee stated that GE engineering was asked to evaluate the effects of SPU on the feedwater turbine control valve and recommended appropriate modifications. The GE assessment concluded that no hardware modifications are necessary in support of the SPU. The existing feedwater flow control valves are sufficient to provide flow at the required pressure drops during SPU conditions. The licensee concluded that the size and control capability of the feedwater flow control valves, together with the hydraulic operation of the condensate and feedwater pumps, provide sufficient flexibility to accommodate plant load rejection transients.

For postulated transients and accident events, the current design feedwater isolation capability using the isolation trip valves remain effective, with the flow control and bypass valves providing backup isolation capability. The isolation trip valves, along with the flow control and associated bypass valves, will continue to meet the existing required closure times for SPU conditions. Containment isolation is accomplished by the check valves on the headers and branch lines inside containment and is unaffected by SPU.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the CFS and concludes that the licensee has adequately accounted for the effects of changes in plant conditions on the design of the CFS. The NRC staff concludes that the CFS will continue to maintain its ability to satisfy feedwater requirements for normal operation and shutdown,

withstand water hammer, maintain isolation capability in order to preserve the system safety function, and not cause failure of safety-related SSCs. The NRC staff further concludes that the CFS will continue to meet the requirements of GDCs 4, 5, and 44. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the CFS.

2.5.6 Waste Management Systems

2.5.6.1 Gaseous Waste Management Systems

Regulatory Evaluation

Gaseous waste management systems (GWMS) involve the gaseous radwaste system, which deals with the management of radioactive gases collected in the offgas system or the waste gas storage and decay tanks. In addition, it involves the management of the condenser air removal system, the SG blowdown flash tank, the containment purge exhausts, and the building ventilation system exhausts. The NRC staff's review focused on the effects that the proposed SPU may have on: (1) the design criteria of the GWMSs; (2) methods of treatment; (3) expected releases; (4) principal parameters used in calculating the releases of radioactive materials in gaseous effluents; and (5) design features for precluding the possibility of an explosion if the potential for explosive mixtures exist. The NRC's acceptance criteria for the GWMS are based on: (1) 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC 3, insofar as it requires that: (a) SSCs important to safety be designed and located to minimize the probability and effect of fires; (b) noncombustible and heat resistant materials be used; and (c) fire detection and fighting systems be provided and designed to minimize the adverse effects of fires on SSCs important to safety; (3) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (4) GDC 61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and (5) 10 CFR Part 50 Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for design objectives and limiting conditions for operation (LCO) to meet the "as low as is reasonably achievable" (ALARA) criterion. Specific review criteria are contained in SRP Section 11.3.

Technical Evaluation

In Section 2.5.6 of the MSP3 LAR, the licensee stated that the proposed SPU would result in an increase in inventory of gas normally processed by the GWMS, but the plant system functions are not changing and the assumptions related to volume inputs remain the same. The implementation of SPU does not add any new sources of potentially contaminated gases, nor does it create any new flow paths or routes that would allow the contamination of uncontaminated gases, nor does it add or change any of the sources of potentially explosive mixtures. The GWMS design capability remains unchanged by the SPU for handling, control, and release of radioactive materials. Thereby, continues to comply with 10 CFR 50, Appendix I, Sections II.B, II.C, and II.D, which set numerical guides for dose design objectives and LCO to meet the ALARA criterion. The evaluation of the GWMS at SPU conditions remain in compliance with 10 CFR 20.1302, insofar as the annual average concentrations of radioactive materials released at the boundary of the unrestricted area will not exceed specified values. This will be demonstrated by the continuing compliance to the annual dose objective of 10 CFR 50, Appendix I upon implementation of SPU. Discharge streams will remain appropriately

monitored and safety features remain incorporated to preclude excessive releases, in accordance with the offsite dose calculation manual.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the GWMS. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of gaseous waste on the abilities of the systems to control releases of radioactive materials and preclude the possibility of an explosion if the potential for explosive mixtures exists. The NRC staff finds that the GWMS will continue to meet their design functions following implementation of the proposed SPU. The NRC staff further concludes that the GWMS will continue to meet the requirements of 10 CFR 20.1302, GDCs 3, 60, and 61, and 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the GWMS.

2.5.6.2 Liquid Waste Management Systems

Regulatory Evaluation

The NRC staff's review for liquid waste management systems (LWMS) focused on the effects that the proposed SPU may have on previous analyses and considerations related to the liquid waste management systems' design, design objectives, design criteria, methods of treatment, expected releases, and principal parameters used in calculating the releases of radioactive materials in liquid effluents. The NRC's acceptance criteria for the liquid waste management systems are based on (1) 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) GDC 61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement; and (4) 10 CFR Part 50, Appendix I, Sections II.A and II.D, which set numerical guides for dose design objectives and LCO to meet the ALARA criterion. Specific review criteria are contained in SRP Section 11.2.

Technical Evaluation

In Section 2.5.6.2 of the MSP3 LAR, the licensee evaluated the impact that SPU would have on the capability of the LWMS. The licensee indicated that before the waste is released, samples are analyzed to determine the types and amounts of radioactivity present. On the basis the analyses results, the waste is recycled for eventual reuse in the plant, retained for further processing, or released under controlled conditions to the circulating water tunnel. A radiation monitor will automatically terminate the liquid waste discharge if radiation measurements exceed a predetermined level.

The SPU results in an increase in the equilibrium radioactivity in the reactor coolant. This change in radioactivity of the reactor coolant impacts the concentrations of radioactive nuclides in the waste disposal systems. It does not, however, increase the inventory of liquid normally processed by the LWMS above system's capability. The implementation of SPU does not add any new sources of potentially contaminated leakage, nor does it create any new flow paths or routes that would contaminate the drainage systems designed for uncontaminated fluids.

Discharge streams will remain appropriately monitored and adequate safety features remain incorporated to preclude releases, in accordance with the offsite dose calculation manual.

Implementation of SPU does not result in physical modifications to LWMS. The system design capability remains unaffected. The handling, control, and release of radioactive materials continue to be in compliance with 10 CFR 50, Appendix I, and as described in the offsite dose calculation manual.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the liquid waste management systems. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of liquid waste on the ability of the liquid waste management systems to control releases of radioactive materials. The NRC staff finds that the liquid waste management systems will continue to meet their design functions following implementation of the proposed SPU. The NRC staff further concludes that the licensee has demonstrated that the liquid waste management systems will continue to meet the requirements of 10 CFR 20.1302, GDCs 60 and 61, and 10 CFR Part 50, Appendix I, Sections II.A and II.D. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the liquid waste management systems.

2.5.6.3 Solid Waste Management Systems

Regulatory Evaluation

The NRC staff's review for the solid waste management systems (SWMS) focused on the effects that the proposed SPU may have on previous analyses and considerations related to the design objectives in terms of expected volumes of waste to be processed and handled, the wet and dry types of waste to be processed, the activity and expected radionuclide distribution contained in the waste, equipment design capacities, and the principal parameters employed in the design of the SWMS. The NRC's acceptance criteria for the SWMS are based on: (1) 10 CFR 20.1302, insofar as it provides for demonstrating that annual average concentrations of radioactive materials released at the boundary of the unrestricted area do not exceed specified values; (2) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents; (3) GDC 63, insofar as it requires that systems be provided in waste handling areas to detect conditions that may result in excessive radiation levels; (4) GDC-64, insofar as it requires that means be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs, and postulated accidents; and (5) 10 CFR Part 71, which states requirements for radioactive material packaging. Specific review criteria are contained in SRP Section 11.4.

Technical Evaluation

Solid radioactive waste consists of wet and dry waste. The SWMS design functions are to collect, hold, and process, dewater or solidify, package, handle, and temporarily store radioactive materials prior to their shipment offsite and ultimate disposal. The NRC staff's review relates primarily to the wet waste dewatering and liquid collection processes, and focuses on the effects that the proposed SPU may have on the release of radioactive material to

the environment via gaseous and liquid effluents. Based on the staff review of the application, the NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of solid waste on the ability of the SWMS to process the waste.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the SWMS. The NRC staff concludes that the licensee has adequately accounted for the effects of the increase in fission product and amount of solid waste on the ability of the SWMS to process the waste. The NRC staff finds that the SWMS will continue to meet its design functions following implementation of the proposed SPU. The NRC staff further concludes that the licensee has demonstrated that the SWMS will continue to meet the requirements of 10 CFR 20.1302, GDCs 60, 63, and 64, and 10 CFR Part 71. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the SWMS.

2.5.7 Additional Considerations

2.5.7.1 Emergency Diesel Engine Fuel Oil Storage and Transfer System

Regulatory Evaluation

Nuclear power plants are required to have redundant onsite emergency power supplies of sufficient capacity to perform their safety functions (e.g., power diesel engine-driven generator sets), assuming a single failure. The NRC staff's review focused on increases in EDG electrical demand and the resulting increase in the amount of fuel oil necessary for the system to perform its safety function. The NRC's acceptance criteria for the emergency diesel engine fuel oil storage and transfer system are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects, including missiles, pipe whip, and jet impingement forces associated with pipe breaks; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC 17, insofar as it requires onsite power supplies to have sufficient independence and redundancy to perform their safety functions, assuming a single failure. Specific review criteria are contained in SRP Section 9.5.4.

Technical Evaluation

Nuclear power plants are required to have redundant onsite emergency power supplies of sufficient capacity to perform their safety functions (e.g., diesel engine-driven generator sets). The NRC staff's review focuses on increases in EDG electrical demand and the resulting increase in the amount of fuel oil necessary for the system to perform its safety function. The calculated EDG fuel oil consumption remains bounding at SPU conditions because there are no changes in the loading duration of operation of equipment. Therefore, the fuel oil storage requirements for the emergency diesel engine fuel oil storage and transfer system are not affected by the proposed SPU.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the amount of required fuel oil for the EDGs and concludes that the licensee has adequately accounted for the effects of the increased electrical demand on fuel oil consumption. The NRC staff concludes that the fuel oil storage and transfer system will continue to provide an adequate amount of fuel oil to allow the diesel generators to meet the onsite power requirements of GDCs 4, 5, and 17. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the fuel oil storage and transfer system.

2.5.7.2 Light Load Handling System (Related to Refueling)

Regulatory Evaluation

The light load handling system (LLHS) includes components and equipment used in handling new fuel at the receiving station and the loading of spent fuel into shipping casks. The NRC staff's review covered the avoidance of criticality accidents, radioactivity releases resulting from damage to irradiated fuel, and unacceptable personnel radiation exposures. The NRC staff's review focused on the effects of the new fuel on system performance and related analyses. The NRC's acceptance criteria for the LLHS are based on: (1) GDC 61, insofar as it requires that systems that contain radioactivity be designed with appropriate confinement and with suitable shielding for radiation protection; and (2) GDC 62, insofar as it requires that criticality be prevented. Specific review criteria are contained in SRP Section 9.1.4.

Technical Evaluation

The LLHS includes components and equipment used in handling new fuel at the receiving station and the loading of spent fuel into shipping casks. Because the post-SPU fuel is mechanically the same as pre-SPU fuel, the staff finds LLHS is not affected by the proposed SPU.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the new fuel on the ability of the LLHS to avoid criticality accidents and concludes that the licensee has adequately incorporated the effects of the new fuel in the analyses. Based on this review, the NRC staff further concludes that the LLHS will continue to meet the requirements of GDCs 61 and 62 for radioactivity releases and prevention of criticality accidents. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the LLHS.

2.6 Containment Review Considerations

2.6.1 Primary Containment Functional Design

Regulatory Evaluation

The containment encloses the reactor system and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident. The MPS3 containment is a subatmospheric containment. It encloses the reactor system and is the final barrier against the release of significant amounts of radioactive fission products in the event of an accident. During normal operation, the containment structure is maintained at a subatmospheric pressure (10.6 psia to 14.0 psia). While operating at SPU condition, and following a design basis LOCA or a MSLB accident, the peak pressure and temperature within the containment must remain below the containment's internal design pressure and design temperature. The containment structure is designed to withstand internal pressurization from high energy pipe breaks within it and the external pressurization due to inadvertent actuation of the containment heat removal systems. The containment maximum internal design pressure is 45 pounds per square inch gauge (psig), the minimum internal design pressure is 8.00 psia, and the containment liner design temperature is 280 ^{o}F.

The NRC staff's review covered the pressure and temperature conditions in the containment due to a spectrum of postulated LOCAs and secondary system line-breaks. The NRC's acceptance criteria for primary containment functional design are based on: (1) GDC 16, insofar as it requires that reactor containment be provided to establish an essentially leak-tight barrier against the uncontrolled release of radioactivity to the environment; (2) GDC 50, insofar as it requires that the containment and its internal components be able to accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated pressure and temperature conditions resulting from any LOCA; (3) GDC 38, insofar as it requires that the containment heat removal system(s) function to rapidly reduce the containment pressure and temperature following any LOCA and maintain them at acceptably low levels; (4) GDC 13, insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation and accident conditions; and (5) GDC 64, insofar as it requires that means be provided for monitoring the plant environs for radioactivity that may be released from normal operations and postulated accidents. Specific review criteria are contained in SRP Section 6.2.1.1.A.

Technical Evaluation

Initial containment design was for a range of 8.9 - 12 pounds per square inch absolute (psia). In MPS3 Amendment No. 59, dated January 25, 1991,[84] the TS 3.6.1.4 LCO for containment initial pressure was changed from a range of 8.9 - 12 psia to the current 10.6 - 14.0.

The licensee used the GOTHIC (Generation of Thermal Hydraulic Information for Containments) computer code version 7.2a methodology for LOCA and MSLB accident containment performance analyses. The GOTHIC containment methodology[85] has been approved by the

[84] ADAMS Accession No. ML011790140

[85] DNC Topical Report DOM-NAF-3-0-0-P-A, "GOTHIC Methodology for Analyzing the Response to Postulated Pipe Ruptures Inside Containment", dated September 2006.

NRC[86]. By comparison with the results of MPS3 current long-term containment performance analyses which used the LOCTIC computer code, the licensee bench-marked the GOTHIC code confirming it will provide conservative results. The licensee used conservative containment initial conditions applicable to the various analyses that would yield the most limiting response. Regarding the passive heat sinks inside the containment, the licensee states that the same general grouping of the passive heat sinks as given in UFSAR Table 6.2-2 was used for SPU. However, the analysis was performed using the most current heat sink physical dimensions. The licensee states that the SPU analysis values of physical and thermal properties for some of the heat sink materials differed slightly from their hard-coded values in the LOCTIC program used in the current analysis, which has negligible impact on the results. However, for the thermal conductivity of concrete, the licensee used a value of 0.54 Btu/hr-ft^2-^{o}F, whereas the current analysis used 0.8 Btu/hr-ft^2-^{o}F. The licensee states that SPU analysis is conservative because the lower thermal conductivity will have less heat transfer to concrete structures and thus maximize the peak containment temperature and pressure.

The staff finds the licensee's justification for the changes in heat sink dimensions and material properties acceptable.

LOCA Short-Term Containment Response

The licensee's results for the short term containment response show that the peak pressure occurs near the end of the initial blowdown and therefore its magnitude is independent of the ECCS or containment heat removal system, because these systems come into operation after the peak pressure occurs. Of the spectrum of breaks analyzed, the highest peak pressure was 56.09 psia occurring at 21.2 seconds from the beginning of blowdown for a double-ended hot leg break (DEHLB). The highest peak temperature was 267.1 ^{o}F occurring at 21.1 seconds from the beginning of blowdown for a DEHLB. The LOCA short-term containment peak pressure is less than the containment design pressure of 45 psig.

LOCA Long-Term Containment Response

The licensee determined that the accident which produces the maximum energy release during the post blowdown period is a double-ended pump suction break (DEPSB). The initial conditions of maximum pressure, maximum temperature and maximum relative humidity along with a single failure or loss of an EDG produces the slowest containment depressurization for this break. The single failure of the EDG causes a loss of one complete train of the ECCS and one complete train of the containment heat removal system. The licensee determined that the peak containment pressure, which occurs during a DEHLB along with the long term limiting containment depressurization profile, is bounded by the EQ pressure value for the qualified equipment inside the containment.

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[86] NRC Letter "Kewaunee Power Station (Kewaunee), Millstone Power Station, Units Nos. 2 and 3 (Millstone 2 and 3), North Anna Power Station, Unit Nos. 1 and 2 (North Anna 1 and 2) and Surry Power Station, Unit Nos. 1 and 2 (Surry 1 and 2) – Approval of Dominion's Topical Report DOM-NAF-3, "GOTHIC Methodology for Analyzing the Response to Postulated Pipe Ruptures Inside Containment" (TAC Nos. MC8831, MC8832, MC8833, MC8834, MC8835 and MC8836)". dated August 30, 2006. (ADAMS Accession No. ML062420511)

The licensee determined that the accident which produces the maximum peak containment temperature is DEHLB with initial containment conditions of maximum pressure, temperature and relative humidity used in the analysis. The peak temperature is independent of a single failure assumption, because it occurs before the ECCS or containment heat removal system comes into operation. The licensee determined the peak temperature along with the slowest containment cooldown long term temperature profile is bounded by the EQ temperature profile for the qualified equipment inside the containment.

Main Steam Line Break Containment Response

The licensee states that the containment initial conditions that result in maximum peak pressure are maximum initial pressure and temperature and minimum initial relative humidity, and the initial conditions that result in maximum peak containment temperature are minimum initial pressure and relative humidity and maximum initial temperature. The licensee calculated a maximum peak containment pressure of 52.85 psia which occurs for a 1.4 ft^2 double-ended break at 0 percent power without liquid entrainment and assuming MSIV failure in the ruptured line. The peak pressure occurs at 194.3 seconds from the time of the instantaneous break. The licensee verified that the pressure profiles for all sixteen cases analyzed are bounded by the EQ pressure value for the qualified equipment inside the containment.

The licensee calculated a maximum peak containment temperature of 343.0 ^oF for a 1.4 ft^2 double-ended break at 102 percent power without liquid entrainment and without closure of the MSIV in the ruptured steam line. The peak temperature occurs at 12.6 seconds from the time of the instantaneous break. The licensee verified that the temperature profiles for all sixteen cases analyzed are bounded by the EQ temperature value for the qualified equipment inside the containment.

The licensee determined the maximum containment liner temperature in accordance with the method in the DNC report[87] for all sixteen cases of M&E release. The maximum calculated liner temperature was found to be 241 ^oF for a 1.4 ft^2 double-ended break at zero percent power, which is below its design value of 280 ^oF.

Conclusion

The NRC staff has reviewed the licensee's assessment of the containment pressure and temperature transient and concludes that the licensee has adequately accounted for the increase of M&E that would result from the proposed SPU. The NRC staff further concludes that containment systems will continue to provide sufficient pressure and temperature mitigation capability to ensure that containment integrity is maintained. The NRC staff also concludes that the containment systems and instrumentation will continue to be adequate for monitoring containment parameters and release of radioactivity during normal and accident conditions and will continue to meet the requirements of GDCs 13, 16, 38, 50, and 64 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to containment functional design.

[87] DNC Topical Report DOM-NAF-3-0-0-P-A, "GOTHIC Methodology for Analyzing the response of Postulated Pipe Ruptures Inside Containment", dated September 2006.

2.6.2 Subcompartment Analyses

Regulatory Evaluation

A subcompartment is defined as any fully or partially enclosed volume within the primary containment that houses high-energy piping and would limit the flow of fluid to the main containment volume in the event of a postulated pipe rupture within the volume. The NRC staff's review for subcompartment analyses covered the determination of the design differential pressure values for containment subcompartments. The NRC staff's review focused on the effects of the increase in M&E released into the containment due to operation at SPU conditions, and the resulting increase in pressurization. The NRC's acceptance criteria for subcompartment analyses are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents, and that such SSCs be protected against dynamic effects; and (2) GDC 50, insofar as it requires that containment subcompartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the subcompartments. Specific review criteria are contained in SRP Section 6.2.1.2.

Technical Evaluation

The NRC has approved LBB methodology for MPS3[88]. According to the LBB methodology, RCS piping determined not to catastrophically rupture does not have to be considered in subcompartment analyses. Therefore, the licensee considered break locations in the pressurizer surge line, the pressurizer spray line, the accumulator line, and the RHR line from the hot leg to the first isolation valve. The current licensing basis includes the pressurizer and SG subcompartments. The licensee states that for the pressurizer subcompartment, the differential pressure across the walls increased by two percent, and the differential pressure across the pressurizer platform increased by 11 percent. The licensee's evaluation showed that the design differential pressure in the current structural analysis for the pressurizer subcompartment remains bounding with no net decrease in design margin. In a response to an RAI, the licensee indicated that calculations were performed for the pressurizer floor slab and the lower pressurizer subcompartment wall to assure that all structural design requirements were met. For the SG subcompartment, the differential pressure across the walls increased by approximately 5 percent which is bounded by the current licensing basis analysis results, because in the current design, the SG compartment is analyzed for a RCS hot leg split break which is approximately 3.5 times bigger than the pressurizer surge line break.

Conclusion

The NRC staff has reviewed the subcompartment assessment performed by the licensee and the change in predicted pressurization resulting from the increased M&E release. The NRC staff concludes that containment SSCs important to safety will continue to be protected from the dynamic effects resulting from pipe breaks and that the subcompartments will continue

[88] NUREG-1838, "Safety Evaluation Report Related to the License Renewal of the Millstone Power Station, Units 2 and 3".

to have sufficient margins to prevent fracture of the structure due to pressure difference across the walls following implementation of the proposed SPU. Based on this, the NRC staff concludes that the plant will continue to meet GDCs 4 and 50 for the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to subcompartment analyses.

2.6.3 Mass and Energy Release

2.6.3.1 Mass and Energy Release Analysis for Postulated Loss of Coolant

Regulatory Evaluation

The release of high-energy fluid into containment from pipe breaks could challenge the structural integrity of the containment, including subcompartments and systems within the containment. The NRC staff's review covered the energy sources that are available for release to the containment and the M&E release rate calculations for the initial blowdown phase of the accident. The NRC's acceptance criteria for M&E release analyses for postulated LOCAs are based on: (1) GDC 50, insofar as it requires that sufficient conservatism be provided in the M&E release analysis to assure that containment design margin is maintained; and (2) 10 CFR Part 50, Appendix K, insofar as it identifies sources of energy during a LOCA. Specific review criteria are contained in SRP Section 6.2.1.3.

Technical Evaluation

The licensee performed the SPU LOCA blowdown, and reflood M&E release analyses using the NRC-approved Westinghouse model[89] [90]. The post-reflood M&E release were determined using the NRC-approved DNC report[91]. The licensee states that nitrogen release from the accumulators is included in the DNC model. In order to verify continuity in transition from the Westinghouse model to the DNC model, the licensee performed a benchmarking comparison of the results obtained from the two methodologies. The licensee used instrument uncertainties and input parameters to obtain conservative M&E release. The evaluation of LOCA M&E release at SPU was performed for a spectrum of breaks which included the largest RCS instantaneous DEHLB, DEPSB, double-ended pump discharge break (DEPDB), and a pump suction split break of 3 ft^2 area.

For containment subcompartment analyses, the licensee used the current licensing basis short-term LOCA M&E release analysis methodology documented in UFSAR Section 6.2.1.2. The licensee determined that the current short term M&E release, which is based on frictionless Moody critical flow model for a single-ended split (SES) FLB within the SG cubicle, bounds the SPU conditions SES FLB based on Moody's critical flow model and applying a flow resistance of fL/D=1.0 at all power levels. For the pressurizer spray line break within the pressurizer cubicle, the SPU M&E release is greater, but is within 10 percent margin included in the current evaluations documented in the UFSAR Table 6.2-31. This pressurizer surge line break impacts

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[89] WCAP-10325-P-A, May 1983 (Proprietary), "Westinghouse LOCA Mass and Energy Release Model for Containment Design," March 1979.

[90] WCAP-8264-P-A, Rev. 1, August 1975 (Proprietary) "Topical Report Westinghouse Mass and Energy Release Data Containment Design."

[91] DNC Topical Report DOM-NAF-3-0-0-P-A, "GOTHIC Methodology for Analyzing the response of Postulated Pipe Ruptures Inside Containment", dated September 2006.

the pressurizer and the SG subcompartments. The licensee states that for the pressurizer compartment, the SPU M&E release is not bounded by the M&E release in the current analysis. The licensee performed pressurizer compartment M&E release sensitivity studies for four initial conditions and found that the limiting case was for initial conditions of 100 ^{o}F, 10.4 psia total pressure and 10 percent relative humidity. For this break under SPU conditions, the licensee determined that the M&E release is greater by 15.75 percent in mass and 11.27 percent in energy than the current licensing basis. Considering a 10 percent margin included in the current licensing basis as listed in UFSAR Table 6.2-32A, the SPU analysis addressed the impact of the additional 5.75 percent mass and the additional 1.27 percent energy released.

Conclusion

The NRC staff has reviewed the licensee's M&E release assessment and concludes that the licensee has adequately addressed the effects of the proposed SPU and appropriately accounts for the sources of energy identified in 10 CFR Part 50, Appendix K. Based on this, the NRC staff finds that the M&E release analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative. Therefore, the NRC staff finds the proposed SPU acceptable with respect to M&E release for postulated LOCA.

2.6.3.2 Mass and Energy Release Analysis for Secondary System Pipe Ruptures

Regulatory Evaluation

The NRC staff's review covered the energy sources that are available for release to the containment, the M&E release rate calculations, and the single-failure analyses performed for steam and feedwater line isolation provisions, which would limit the flow of steam or feedwater to the assumed pipe rupture. The NRC's acceptance criteria for M&E release analysis for secondary system pipe ruptures are based on GDC 50, insofar as it requires that the margin in the design of the containment structure reflect consideration of the effects of potential energy sources that have not been included in the determination of peak conditions, the experience and experimental data available for defining accident phenomena and containment response, and the conservatism of the model and the values of input parameters. Specific review criteria are contained in SRP Section 6.2.1.4.

Technical Evaluation

As per UFSAR Section 6.2.1.4, M&E is released inside containment following a postulated rupture of a steam or a feedwater line. The FLB M&E release is bounded by the MSLB M&E release, because feedwater total enthalpy release rate at any power would be less than the total enthalpy release rate of saturated steam at the SG operating pressure. Therefore, the containment pressure and temperature response due to FLB will be bounded by the containment response due to MSLB. The licensee analyzed 16 MSLB M&E release cases at 102, 70, 30, and 0 percent of SPU. As per NRC-approved Westinghouse methods[92], the break cases to be analyzed are:

[92] WCAP-8822 (Proprietary), "Mass and Energy Releases Following a Steam Line Rupture," September 1976;
WCAP-8822-S1-P-A (Proprietary), Supplement 1 – "Calculations of Steam Superheat in Mass/Energy Releases Following a Steam Line Rupture," September 1986;
WCAP-8822-S2-P-A (Proprietary), Supplement 2 –"Impact of Steam Superheat in Mass/Energy Releases Following a Steam Line Rupture for Dry and Subatmospheric Containment Designs," September 1986.

(a) A full double ended (DE) rupture at the SG nozzle;

(b) A small DE rupture at the SG nozzle having an area just larger than that at which water entrainment occurs;

(c) A small DE rupture at the SG nozzle having an area just smaller than that at which water entrainment occurs; and

(d) A small split rupture that will neither generate a steam line isolation signal nor result in water entrainment in the break effluent.

The licensee states it is unnecessary to analyze case (b) and (c) because these are bounded by case (a). The licensee analyzed cases (a) and (d) and found that case (a) was acceptable because it bounded case (d). The licensee used conservative assumptions and input values, by including their uncertainties in order to maximize the mass or energy release in the containment. The SPU M&E release analysis methodology that was used by the licensee was developed by Westinghouse using LOFTRAN computer code[93] which has been approved by the NRC. The NRC staff finds the licensee's results acceptable.

Conclusion

The NRC staff has reviewed the M&E release assessment performed by the licensee for postulated secondary system pipe ruptures and finds that the licensee has adequately addressed the effects of the proposed SPU. Based on this, the NRC staff concludes that the analysis meets the requirements in GDC 50 for ensuring that the analysis is conservative (i.e., that the analysis includes sufficient margin). Therefore, the NRC staff finds the proposed SPU acceptable with respect to M&E release for postulated secondary system pipe ruptures.

2.6.4 Combustible Gas Control in Containment

Regulatory Evaluation

Following a LOCA, hydrogen and oxygen may accumulate inside the containment due to chemical reactions between the fuel rod cladding and steam, corrosion of aluminum and other materials, and radiolytic decomposition of water. If excessive hydrogen is generated, it may form a combustible mixture in the containment atmosphere. The NRC staff's review covered: (1) the production and accumulation of combustible gases; (2) the capability to prevent high concentrations of combustible gases in local areas; (3) the capability to monitor combustible gas concentrations; and (4) the capability to reduce combustible gas concentrations. The NRC staff's review primarily focused on any impact that the proposed SPU may have on hydrogen release assumptions, and how increases in hydrogen release are mitigated. The NRC's acceptance criteria for combustible gas control in containment are based on: (1) 10 CFR 50.44, insofar as it requires that plants be provided with the capability for controlling combustible gas concentrations in the containment atmosphere; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions;

[93] WCAP-7907-P-A (Proprietary), "LOFTRAN Code Description," April 1984.

(3) GDC 41, insofar as it requires that systems be provided to control the concentration of hydrogen or oxygen that may be released into the reactor containment following postulated accidents to ensure that containment integrity is maintained; (4) GDC 42, insofar as it requires that systems required by GDC-41 be designed to permit appropriate periodic inspection; and (5) GDC 43, insofar as it requires that systems required by GDC 41 be designed to permit appropriate periodic testing. Specific review criteria are contained in SRP Section 6.2.5.

Technical Evaluation

The licensee submitted an LAR by letter dated September 8, 2004,[94] requesting revision in TS requirements associated with hydrogen recombiners and hydrogen monitors. The NRC staff approved the LAR which removed hydrogen recombiners from the TS, and reclassified the monitoring system from safety-related to non-safety related consistent with RG 1.97.[95] The licensee will maintain the hydrogen monitoring system as described in the UFSAR. This will not be affected by the SPU. The licensee evaluated that the containment atmosphere mixing mechanism following a design-basis accident (DBA) as described in the UFSAR, and concludes that it is not impacted by the SPU. The NRC staff finds the licensee's evaluation acceptable because it is reasonable that the containment atmospheric mixing mechanism is unaffected by SPU.

Conclusion

The NRC staff has reviewed the licensee's assessment related to combustible gas and concludes that the plant will continue to have sufficient capabilities, consistent with the requirements in 10 CFR 50.44, 10 CFR 50.46, and GDCs 5, 41, 42, and 43 as discussed above. Therefore, the NRC staff finds the proposed SPU acceptable with respect to combustible gas control in containment.

2.6.5 Containment Heat Removal

Regulatory Evaluation

Fan cooler systems, spray systems, and RHR systems are provided to remove heat from the containment atmosphere and from the water in the containment sump. The NRC staff's review in this area focused on: (1) the effects of the proposed SPU on the analyses of the available NPSH to the containment heat removal system pumps; and (2) the analyses of the heat removal capabilities of the spray water system and the fan cooler heat exchangers. The NRC's acceptance criteria for containment heat removal are based on GDC 38, insofar as it requires that the containment heat removal system be capable of rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels. Specific review criteria are contained in SRP Section 6.2.2 as supplemented by Draft Guide (DG) 1107.[96]

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[94] DNC Letter to NRC, "Virginia Electric And Power Company, Dominion Nuclear Connecticut, Inc., Surry Power Station Units 1 And 2 North Anna Power Station Units 1 And 2 Millstone Power Station Units 2 And 3, Application for Technical Specification Improvement to Eliminate Requirements For Hydrogen Recombiners and Hydrogen Monitors using the Consolidated Line Item Improvement Process". (ADAMS Accession No. ML042650363)

[95] Regulatory Guide 1.97, "Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants, Revision 4," Dated June 2006. (ADAMS Accession No. ML061580448)

[96] Draft Regulatory Guide DG-1107 "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant

Technical Evaluation

The containment heat removal systems consists of the quench spray system (QSS) and the recirculation spray system (RSS). The QSS pumps only take suction from the refueling water storage tank (RWST) and therefore its NPSH calculation is unaffected by the SPU. In order to address generic safety issue (GSI)-191,[97] by a letter dated June 13, 2006,[98] the licensee submitted a supplement to an LAR dated September 13, 2005,[99] which revised the RSS pump NPSH calculation to account for the installation of a new sump strainer and increase in head loss due to postulated increased debris generation. The staff approved the LAR by a letter dated September 20, 2006.[100] MPS3 does not credit containment accident pressure for calculation of the net positive suction head available (NPSHA) in its licensing bases. The licensee states that the SPU input parameters for calculation of RSS pump NPSHA were the same or conservative with respect to the input parameters in the current analysis performed to resolve GSI-191. The licensee performed containment sump water maximum temperature analysis using the GOTHIC code and determined that the DEPDB analyzed with containment initial conditions of minimum pressure, maximum temperature and relative humidity along with a single active failure of an EDG, (i.e., loss of one ECCS train and one containment heat removal system train, yields the maximum sump temperature of 221.6 ^{o}F at the start of the RSS.) Therefore, the RSS pump NPSHA is unaffected by SPU.

Conclusion

The NRC staff has reviewed the containment heat removal systems assessment provided by the licensee and concludes that the licensee has adequately addressed the effects of the proposed SPU. The NRC staff finds that the systems will continue to meet GDC 38 for rapidly reducing the containment pressure and temperature following a LOCA, and maintaining them at acceptably low levels. Therefore, the NRC staff finds the proposed SPU acceptable with respect to containment heat removal systems.

2.6.6 Pressure Analysis for ECCS Performance Capability

Regulatory Evaluation

Following a LOCA, the ECCS will supply water to the reactor vessel to reflood, and thereby cool the reactor core. The core flooding rate will increase with increasing containment pressure. The NRC staff reviewed analyses of the minimum containment pressure that could exist during the period of time until the core is reflooded to confirm the validity of the containment pressure used in ECCS performance capability studies. The NRC staff's review covered assumptions made regarding heat removal systems, structural heat sinks, and other heat removal processes

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Accident"

[97] Generic Safety Issue (GSI) -191, "Assessment of Debris Accumulation on Pressurized Water Reactor Pump Performance"

[98] DNC letter to the NRC, "Millstone Power Station Unit 3, Supplement to Proposed Technical Specification Change, Recirculation Spray System," dated June 13, 2006. (ADAMS Accession No. ML06050054)

[99] DNC letter to the NRC, "Millstone Power Station Unit 3, Proposed Technical Specifications Change, Recirculation Spray System," dated September 13, 2005. (ADAMS Accession No. ML052580387)

[100] NRC letter to DNC, "Millstone Power Station, Unit No. 3, Issuance Of Amendment Re: Recirculation Spray System (TAC No. MC8327)," dated September 20, 2006. (ADAMS Accession No. ML062220160)

that have the potential to reduce the pressure. The NRC's acceptance criteria for the pressure analysis for ECCS performance capability are based on 10 CFR 50.46, insofar as it requires the use of an acceptable ECCS evaluation model that realistically describes the behavior of the reactor during LOCAs or an ECCS evaluation model developed in conformance with 10 CFR Part 50, Appendix K. Specific review criteria are contained in SRP Section 6.2.1.5.

Technical Evaluation

UFSAR Figure 6.2-59 provides the current containment backpressure profile used for ECCS performance analysis. For re-evaluation of the containment backpressure at SPU, the licensee updated the passive heat sink data by adding the design changes, including the sump strainer, and calculated conservative initial pressure and temperature in the containment. The licensee used the Westinghouse COCO computer code, the same as used in the current analysis to perform the SPU containment pressure analysis for ECCS performance. The licensee showed that the calculated containment pressure-time transient bounds the transient used in the ECCS performance evaluation computer code. The NRC staff finds the licensee's evaluation acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the proposed SPU would have on the minimum containment pressure analysis and concludes that the licensee has adequately addressed this area of review to ensure that the requirements in 10 CFR 50.46 regarding ECCS performance will continue to be met following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to minimum containment pressure for ECCS performance.

2.6.7 Reconsideration of Generic Letter 96-06

Regulatory Evaluation

The NRC staff has reviewed the impact of Generic Letter (GL) 96-06[101] for SPU, which states: "Thermally induced overpressurization of isolated water-filled piping sections in containment could jeopardize the ability of accident-mitigating systems to perform their safety functions and could also lead to a breach of containment integrity via bypass leakage. Corrective actions may be needed to satisfy system operability requirements."

Technical Evaluation

In an RAI, the NRC staff requested the licensee to verify that the GL 96-06 issues were reconsidered for the SPU conditions, and to confirm that the piping systems that penetrate the containment which are susceptible to thermal expansion of the fluid and overpressurization will remain within their design limits. In its response to the RAI, the licensee stated that the piping systems that penetrate containment along with their thermal relief valves were evaluated for SPU as part of their system design pressure and temperature evaluation. The licensee concluded that no SPU changes were required in the piping and the thermal relief valves. The

[101] Generic Letter 96-06, "Assurance of Equipment Operability and Containment Integrity During Design Basis Accident Conditions," dated September 20, 1996

NRC staff has reviewed the licensee's assessment of the impact that the proposed SPU would have on the resolution to GL 96-06 issue of overpressurization of piping systems that penetrate the containment due to thermal expansion of the piping fluid, and considers it as resolved.

Conclusion

The NRC staff has reviewed the licensee's assessment of the impact that the proposed SPU would have on the resolution to GL 96-06 issue of overpressurization of piping systems that penetrate the containment due to thermal expansion of the piping fluid, and considers it as resolved. Therefore, the staff finds the proposed SPU acceptable with respect to the GL 96-06 issue of overpressurization of piping systems that penetrates containment.

2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

Regulatory Evaluation

The NRC staff reviewed the CR habitability system and control building layout and structures to ensure that plant operators are adequately protected from the effects of accidental releases of toxic and radioactive gases. A further objective of the NRC staff's review was to ensure that the CR can be maintained as the backup center from which technical support center personnel can safely operate in the case of an accident. The NRC staff's review focused on the effects of the proposed SPU on radiation doses, toxic gas concentrations, and estimates of dispersion of airborne contamination. The NRC's acceptance criteria for the CR habitability system are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with postulated accidents, including the effects of the release of toxic gases; and (2) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the CR under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident. Specific review criteria are contained in SRP Section 6.4 and other guidance provided in Matrix 7 of RS-001.

Technical Evaluation

The licensee evaluated the effects of SPU and states that the CR emergency ventilation is impacted by the SPU due to changes in post-accident radiological consequences. The changes made by the licensee for the CR ventilation dose analysis are: (1) filter efficiencies are changed from 90 percent to 95 percent for elemental iodine; 90 percent to 95 percent for aerosol iodine; and 70 percent to 95 percent for organic iodine, consistent with current TS Section 3.0, Surveillance Requirement 4.7.7; (2) for a fuel handling accident (FHA), the CR emergency ventilation system (CREVS) is required to be in the filtered recirculation MODE within 30 minutes of the accident, whereas in the current licensing basis analysis it is required to be in the pressurized filtration MODE within 1.685 hours[102] of the accident; (3) for a LOCA or a RCCA ejection accident (REA), operator action is no longer credited to trip breakers for the ESF building, auxiliary building and MSV building normal exhaust fans as in the off-site dose analysis. The CR does not serve as the backup to the Technical Service Center (TSC) in the current licensing basis. The TSC is located adjacent to the MPS3 control building. The NRC staff considers the current licensing basis acceptable for SPU, because the backup TSC is located in the Emergency Operations Facility, which is located outside of the MPS3 protected area.

The SPU has no impact on toxic gas concentrations; therefore, the current toxic gas analyses remain bounding for the SPU conditions.

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102 DNC letter to NRC, "Dominion Nuclear Connecticut, Inc., Millstone Power Station Unit 3, Response to Request for Additional Information Regarding Stretch Power Uprate License Amendment Request, Response to Question AADB-07-0107," dated January 18, 2007, Attachment 2, Page 48 of 95.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed SPU on the ability of the CR habitability system to protect plant operators against the effects of accidental releases of toxic and radioactive gases. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from the proposed SPU. The NRC staff further concludes that the CR habitability system will continue to provide the required protection following implementation of the proposed SPU. Based on this, the NRC staff concludes that the CR habitability system will continue to meet the requirements of GDCs 4 and 19. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the CR habitability system.

2.7.2 Engineered Safety Feature Atmosphere Cleanup

Regulatory Evaluation

ESF atmosphere cleanup systems are designed for fission product removal in post-accident environments. These systems generally include primary systems (e.g., in-containment recirculation) and secondary systems (e.g., emergency or post-accident air-cleaning systems) for the fuel-handling building, CR, shield building, and areas containing ESF components. For each ESF atmosphere cleanup system, the NRC staff's review focused on the effects of the proposed SPU on system functional design, environmental design, and provisions to preclude temperatures in the adsorber section from exceeding design limits. The NRC's acceptance criteria for the ESF atmosphere cleanup systems are based on: (1) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the CR under accident conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent, to any part of the body, for the duration of the accident; (2) GDC 41, insofar as it requires that systems to control fission products released into the reactor containment be provided to reduce the concentration and quality of fission products released to the environment following postulated accidents; (3) GDC 61, insofar as it requires that systems that may contain radioactivity be designed to assure adequate safety under normal and postulated accident conditions; and (4) GDC 64, insofar as it requires that means shall be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including AOOs, and postulated accidents. Specific review criteria are contained in SRP Section 6.5.1.

Technical Evaluation

The systems that are included in the ESF atmosphere cleanup systems are:

(1) CR emergency ventilation system;

(2) The charging pump, CCW pump and heat exchanger exhaust ventilation systems;

(3) Supplementary leak collection and release system (SLCRS);

(4) Quench spray system (QSS); and

(5) Recirculation spray system (RSS).

For each ESF atmosphere cleanup system, the NRC staff's review focused on the effects of the proposed SPU on system functional design and environmental design. The evaluation of CREVS, which also is a part of CR habitability, is discussed in Section 2.7.1 above. The licensee evaluated the QSS and RSS systems as primary containment fission product removal systems in Section 2.5.3 of LAR and the SPU impact of LOCA radiological consequences in Section 2.9.2 of the LAR. The licensee also evaluated the impact of SPU on containment sump pH by using the pre-SPU method given in a letter dated June 13, 2006,[103] using the same assumptions with minor changes in the initial conditions to reflect changes since the pre-SPU evaluation. The pH value stayed above 7.0 during the period that the RSS was assumed to operate and its ultimate value at 30 days post-LOCA was determined to be 7.05. The licensee evaluated the SLCRS as a secondary containment fission product removal system in Section 2.5.3 of LAR and the SPU impact of LOCA radiological consequences in Section 2.9.2 of LAR. The evaluation of the charging pump, CCW pump and heat exchanger exhaust ventilation system, which are in the auxiliary building, is given in Section 2.7.5 below.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the ESF atmosphere cleanup systems. The NRC staff concludes that the licensee has adequately accounted for the increase of fission products and changes in expected environmental conditions that would result from the proposed SPU, and the NRC staff further concludes that the ESF atmosphere cleanup systems will continue to provide adequate fission product removal in post-accident environments following implementation of the proposed SPU. Based on this, the NRC staff concludes that the ESF atmosphere cleanup systems will continue to meet the requirements of GDCs 19, 41, 61, and 64. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the ESF atmosphere cleanup systems.

2.7.3 Ventilation Systems

2.7.3.1 Control Room Area Ventilation System

Regulatory Evaluation

The function of the control room area ventilation system (CRAVS) is to provide a controlled environment for the comfort and safety of CR personnel and to support the operability of CR components during normal operation, AOOs, and DBA conditions. The NRC's review of the CRAVS focused on the effects that the proposed SPU will have on the functional performance of safety-related portions of the system. The review included the effects of radiation, combustion, and other toxic products; and the expected environmental conditions in areas served by the CRAVS. The NRC's acceptance criteria for the CRAVS are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the CR under accident

[103] DNC letter to the NRC, "Millstone Power Station Unit 3, Supplement to Proposed Technical Specification Change, Recirculation Spray System," dated June 13, 2006. (ADAMS Accession No. ML062050054)

conditions without personnel receiving radiation exposures in excess of 5 rem whole body, or its equivalent to any part of the body, for the duration of the accident; and (3) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.1.

Technical Evaluation

The CRAVS consists of the following subsystems:

(1) CR air conditioning subsystem;

(2) CR emergency air filtration system;

(3) Instrument rack and the computer room air conditioning subsystem;

(4) Switchgear air conditioning subsystem;

(5) Chiller equipment space ventilation subsystem;

(6) CR toilet and kitchenette exhaust ventilation subsystem;

(7) Purge ventilation subsystem; and

(8) Battery room ventilation subsystem.

The licensee determined that the CRAVS heat loads are not impacted by SPU and the SPU does not affect the maximum CR temperature for an 8-hour SBO event as determined in the current analysis. Evaluation of the CR habitability is provided in Section 2.7.1 above.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the ability of the CRAVS to provide a controlled environment for the comfort and safety of CR personnel and to support the operability of CR components. The NRC staff concludes that the licensee has adequately accounted for the increase of toxic and radioactive gases that would result from a DBA under the conditions of the proposed SPU, and associated changes to parameters affecting environmental conditions for CR personnel and equipment. Accordingly, the NRC staff concludes that the CRAVS will continue to provide an acceptable CR environment for safe operation of the plant following implementation of the proposed SPU. The NRC staff also concludes that the system will continue to suitably control the release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the CRAVS will continue to meet the requirements of GDCs 4, 19, and 60. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the CRAVS.

2.7.4 Spent Fuel Pool Area Ventilation System

Regulatory Evaluation

The function of the spent fuel pool area ventilation system (SFPAVS) is to maintain ventilation in the SFP equipment areas, permit personnel access, and control airborne radioactivity in the area during normal operation, AOOs, and following postulated FHAs. The NRC staff's review focused on the effects of the proposed SPU on the functional performance of the safety-related portions of the system. The NRC's acceptance criteria for the SFPAVS are based on: (1) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) GDC 61, insofar as it requires that systems which contain radioactivity be designed with appropriate confinement and containment. Specific review criteria are contained in SRP Section 9.4.2.

Technical Evaluation

The licensee states that although the decay heat in the SFP increases under SPU conditions, the change in the ventilation heat load would depend on the SFP temperature. In Section 2.5.4.1.2.3.5 of the LAR, the licensee states that the current design basis heat load resulting from a full-core offload in the SFP used in single active failure analysis bounds the heat load resulting from a full-core offload under SPU conditions. Therefore, the SPU SFP temperature is bounded by the SFP temperature in the current licensing basis analysis. The NRC staff accepts the licensee's evaluation because the SFP temperature is unaffected by SPU and, therefore, the SFP area ventilation system will maintain the required temperature conditions for personnel and equipment during SPU operation. The licensee states that the exhaust filters that collect the airborne radioactive particles are unaffected because the ventilation system will not change for SPU conditions. The staff finds the licensee's evaluation acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the SFPAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the system's capability to maintain ventilation in the SFP equipment areas, permit personnel access, control airborne radioactivity in the area, control release of gaseous radioactive effluents to the environment, and provide appropriate containment. Based on this, the NRC staff concludes that the SFPAVS will continue to meet the requirements of GDCs 60 and 61. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the SFPAVS.

2.7.5 Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems

Regulatory Evaluation

The function of the auxiliary and radwaste area ventilation system (ARAVS) and the turbine area ventilation system (TAVS) is to maintain ventilation in the auxiliary and radwaste equipment and turbine areas, permit personnel access, and control the concentration of airborne radioactive material in these areas during normal operation, during AOOs, and after postulated accidents. The NRC staff's review focused on the effects of the proposed SPU on the functional performance of the safety-related portions of these systems. The NRC's

acceptance criteria for the ARAVS and TAVS are based on GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Sections 9.4.3 and 9.4.4.

Technical Evaluation

The licensee determined that due to the changes in the piping systems operating conditions, there is an insignificant increase in heat load in these buildings. The licensee states that the evaluation of the plant equipment changes for the SPU conditions did not require modification of these systems, and no plant equipment changes are required that could create a new potentially unmonitored radioactive release path. The staff finds the licensee's evaluation acceptable, because the licensee determined that an insignificant increase in heat load did not affect the ventilation equipment and the capability to control and minimize the release of airborne particles to the environment is maintained.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the ARAVS and TAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the capability of these systems to maintain ventilation in the auxiliary and radwaste equipment areas and in the turbine area, permit personnel access, control the concentration of airborne radioactive material in these areas, and control release of gaseous radioactive effluents to the environment. Based on this, the NRC staff concludes that the ARAVS and TAVS will continue to meet the requirements of GDC 60. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the ARAVS and the TAVS.

2.7.6 Engineered Safety Feature Ventilation System

Regulatory Evaluation

The function of the engineered safety feature ventilation system (ESFVS) is to provide a suitable and controlled environment for ESF components following certain anticipated transients and DBAs. The NRC staff's review for the ESFVS focused on the effects of the proposed SPU on the functional performance of the safety-related portions of the system. The NRC staff's review also covered: (1) the ability of the ESF equipment in the areas being serviced by the ventilation system to function under degraded ESFVS performance; (2) the capability of the ESFVS to circulate sufficient air to prevent accumulation of flammable or explosive gas or fuel-vapor mixtures from components (e.g., storage batteries and stored fuel); and (3) the capability of the ESFVS to control airborne particulate material (dust) accumulation. The NRC's acceptance criteria for the ESFVS are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC 17, insofar as it requires onsite and offsite electric power systems be provided to permit functioning of SSCs important to safety; and (3) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 9.4.5.

Technical Evaluation

The areas served by the ESF ventilation system are ESF building, diesel generator building, service water pumphouse building, and hydrogen recombiner building. The licensee determined that the diesel generator building, service water pumphouse building, and the hydrogen recombiner building heat load will not increase under SPU conditions. The licensee determined that there is an insignificant increase in its heat load in the ESF building due to changes in the piping system operating conditions, which does not impact the ventilation equipment. The licensee states that the ESF ventilation system can withstand a single active component failure or failure of its Class 1E electric power sources without degrading the performance of its safety function. The licensee evaluated the system under SPU conditions and ensured its capability of circulating sufficient air for preventing accumulation of flammable or explosive gases, and also its ability to control airborne particulate material accumulation. The licensee states that the evaluation of the plant equipment changes for the SPU conditions did not require modification of these systems, and no plant equipment changes are required that could create a new potentially unmonitored radioactive release path. The staff finds the licensee's evaluation acceptable, because the licensee determined the ventilation equipment and the capability to control and minimize the release of airborne particles to the environment is maintained.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the ESFVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the ability of the ESFVS to provide a suitable and controlled environment for ESF components. The NRC staff further concludes that the ESFVS will continue to assure a suitable environment for the ESF components following implementation of the proposed SPU. The NRC staff also concludes that the ESFVS will continue to suitably control the release of gaseous radioactive effluents to the environment following implementation of the proposed SPU. Based on this, the NRC staff concludes that the ESFVS will continue to meet the requirements of GDCs 4, 17 and 60. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the ESFVS.

2.7.7 Containment Structure Ventilation System

Regulatory Evaluation

The functions of the containment structure ventilation system are to maintain bulk air temperature in the containment suitable for personnel and equipment operation, filtration of the containment atmosphere, reducing the concentration of airborne radioactive particles and iodine for permitting personnel access, reduce airborne radioactivity in containment during reactor shutdown and provide outside air during personnel occupancy periods, and to maintain CRDM magnetic coils below the maximum allowable temperature during normal reactor operation. The NRC staff's review focused on the effects of the proposed SPU on the functional performance of the system. The NRC's acceptance criteria for the system are based on GDC 2, insofar as it requires that SSCs important to safety be designed to withstand the effects of earthquakes without loss of capability to perform their safety functions.

Technical Evaluation

The containment structure ventilation system consists of four subsystems which are:

(1) Containment air recirculation subsystem;

(2) Containment air filtration subsystem;

(3) Containment purge air subsystem; and

(4) CRDM ventilation and cooling subsystem.

In order to verify that the containment air recirculation subsystem can perform its intended functions under SPU conditions, the licensee evaluated the increase in its containment heat load during normal reactor operation. The evaluation showed an insignificant increase in the heat load which resulted in an increase of less than 1 ^{o}F for the containment bulk operating temperature, which does not lead to the current value of maximum containment bulk air temperature of 120°F be exceeded. The containment air filtration subsystem, which reduces the concentration of airborne radioactive particles and iodine in the containment for permitting personnel access, is not affected by the SPU. For the containment purge air subsystem, the licensee states that the SPU does not require changes to the safety-related containment purge supply and exhaust valves, which also perform the function of containment isolation during DBAs, because the containment peak pressure during DBAs stays below the current licensing basis design pressure of 45 psig as evaluated in Section 2.6.1 above. The licensee's evaluation of the CRDM ventilation and cooling subsystem is given in LAR Section 2.8.4.1, where the licensee states that the performance of the CRDM cooling system and maximum heat load on containment from this system are not affected by the SPU because the maximum reactor vessel head temperature remains unchanged.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed SPU on the containment structure ventilation system. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the capability of its subsystems to perform their intended functions. The NRC staff concludes that containment structure ventilation system will continue to meet the requirements of GDC 2. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the containment structure ventilation system.

2.8 Reactor Systems

2.8.1 Fuel System Design

Regulatory Evaluation

The fuel system consists of arrays of fuel rods, burnable poison rods, spacer grids and springs, end plates, and reactivity control rods. The NRC staff reviewed the fuel system to ensure that: (1) the fuel system is not damaged as a result of normal operation and AOOs; (2) fuel system damage is never so severe as to prevent control rod insertion when it is required; (3) the number of fuel rod failures is not underestimated for postulated accidents; and (4) coolability is always maintained. The NRC staff's review covered fuel system damage mechanisms, limiting values for important parameters, and performance of the fuel system during normal operation, AOOs, and postulated accidents. The NRC's acceptance criteria are based on:
(1) 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance; (2) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (3) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (4) GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA. Specific review criteria are contained in SRP Section 4.2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The fuel systems that have been placed in service at MPS3 include Westinghouse 17x17 fuel matrices of the Standard (STD), VANTAGE 5 Hybrid (V5H), Robust Fuel Assembly (RFA) and RFA-2 designs. RFA fuel geometry characteristics remain the same as the V5H design, with re-designed mid-grids and the introduction of intermediate flow mixers.

The licensee stated that no mechanical changes will be made to the fuel system design; uprated fuel will be of the RFA/RFA-2 mechanical design. The RFA and RFA-2 mechanical fuel design is based on the VANTAGE+ fuel design, as is the V5H design. The licensee stated that analyses and testing have been performed and confirm that the RFA/RFA-2 design is structurally and mechanically acceptable for the MPS3 uprate operation. The licensee also stated that use of re-inserted previously irradiated VANTAGE 5H assemblies is also acceptable for uprate operation.

The licensee stated that the fuel in use at MPS3 is designed for compliance with the fuel rod design criteria presented in SRP Section 4.2. For all fuel designs in use at MPS3, the same design bases are applicable.

The compliance of RFA/RFA-2 fuel with the design bases is discussed in WCAP-12610-P-A, "VANTAGE+ Fuel Assembly Reference Core Report."[104] The applicability of the VANTAGE+ fuel assembly design criteria to the RFA and RFA-2 fuel designs was subsequently confirmed by Westinghouse via the Fuel Criterion Evaluation Process (FCEP).[105] The FCEP is an NRC-approved process whereby Westinghouse may make minor changes to its fuel designs without prior NRC approval. Westinghouse must notify the NRC when such changes are made. FCEP notifications for the RFA and RFA-2 fuel designs were made to the NRC on September 30, 1998, and August 31, 2001, respectively.[106]

Because the licensee identified the applicable fuel design bases, and because these design bases will not change for uprate operation at MPS3, the staff finds that the mechanical design for the uprated fuel and for the currently loaded fuel, will be acceptable, provided that the phenomena that change as a result of the uprate are appropriately evaluated.

Westinghouse evaluated the fuel system design for its acceptability at uprated conditions. As stated previously, increases in both core flow and temperature gradients will result from implementation of the proposed power uprate. The licensee stated that assembly lift forces and hold down force margin were evaluated. The calculations conservatively assumed 75,000 megawatt-day/metric ton uranium (MWD/MTU) high burnup fuel assembly growth and hold down spring relaxation. Westinghouse has also performed experimental testing of the RFA/RFA-2 fuel assemblies that demonstrates acceptable mechanical performance.[107]

Westinghouse's evaluations demonstrate that the fuel system will perform acceptably under uprated conditions during a seismic event or a LOCA. For seismic events, evaluations demonstrated that fragmentation of the fuel rods does not occur as a result of the seismic loads, and that the ability to insert control rods is maintained. As a direct result of a LOCA blowdown load, fragmentation of the fuel rod will not occur and the ability to insert control rods is maintained, and coolable geometry is maintained. Maximum loads for these events were calculated and compared to the allowable grid crush strength, and differences between the RFA and V5H assemblies were evaluated to demonstrate acceptability of re-insertion of previously irradiated V5H assemblies.

Similar to evaluation at the current license conditions, fuel rod performance for the uprated core was evaluated using a reference fuel system comprised entirely of RFA/RFA-2 fuel, and included two transition cycles and an equilibrium uprate cycle. To support fuel reloads, analyses will be performed on a cycle-specific basis using Westinghouse's NRC-approved

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[104] WCAP-12610-P-A, "VANTAGE+ Fuel Assembly Reference Core Report," Westinghouse Electric Corporation, April 1995.
[105] WCAP-12488-P-A, "Westinghouse Fuel Criteria Evaluation Process," Westinghouse Electric Corporation, October, 1994.
[106] NSD-NRC-98-5796, "Fuel Criteria Evaluation process Notification for the 17x17 Robust Fuel Assembly with IFM Grid Design," Westinghouse Electric Corporation, October 13, 1998; and
LTR-ESI-01-154, "Transmittal of EVAL-01-066: GENERIC-Implementation of Robust Fuel Assembly-2 (RFA-2) Design Changes," Westinghouse Electric Corporation, August 31, 2001.
[107] NSD-NRC-98-5796, "Fuel Criteria Evaluation process Notification for the 17x17 Robust Fuel Assembly with IFM Grid Design," Westinghouse Electric Corporation, October 13, 1998; and
LTR-ESI-01-154, "Transmittal of EVAL-01-066: GENERIC-Implementation of Robust Fuel Assembly-2 (RFA-2) Design Changes," Westinghouse Electric Corporation, August 31, 2001.

computational fuel rod design tool, PAD4.0.[108] The PAD4.0 code accepts inputs for core performance and calculates the interrelated effects of temperature, pressure, clad elastic and plastic behavior, fission gas release, and fuel densification and swelling as functions of time and linear power. The code is approved to evaluate fuel to a maximum rod average burnup of 62,000 MWD/MTU.

The fuel rod design analysis demonstrates acceptable performance of the fuel rods at uprated condition. The licensee evaluated rod internal pressure by analyzing gas inventories, rod internal volumes, and gas temperature. The clad stress and strain evaluation considered clad temperature and irradiation effects on yield strength. An evaluation of cladding oxidation and hydriding based on clad surface temperatures concluded that applicable temperature limits were satisfied, and base metal wastage of the Zircaloy-4 and ZIRLO grids and guide tubes were shown not to exceed the design limit at EOL. The hydrogen pickup criterion has been met, which demonstrates an acceptably limited loss of ductility due to hydrogen embrittlement resulting from the formation of zirconium hydride platelets. Thermal and mechanical modeling of the fuel pellets demonstrated acceptable fuel surface, average, and centerline temperatures. The clad fatigue evaluation used a limiting fatigue duty cycle consisting of daily load follow maneuvers, and the cumulative fatigue usage factor was less than the 1.0 design limit. The licensee referenced a generic disposition of clad flattening, noting that the NRC-approved generic report, "Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel," WCAP-13589-A,[109] concluded that clad flattening does not occur in Westinghouse fuel designs. A fuel growth evaluation demonstrates that there is adequate margin to the fuel rod growth design limit. The RFA/RFA-2 helical coil spring was shown to provide enough support to prevent potential clad collapse. Finally, generic analyses for Westinghouse fuel rod geometries show that instantaneous collapse of the MPS3 fuel is precluded for differential pressures well in excess of the maximum expected differential pressure across the clad under operating conditions.

Based on its review of the licensee's application, the NRC staff concludes the following:

- The MPS3 fuel system is acceptable with respect to its ability to withstand fuel system damage at uprated conditions. This conclusion is based on acceptable results of fuel rod performance evaluations of clad stress and strain, oxidation, clad fatigue, and internal pressure, and calculations of the hydraulic loads based on assembly lift and hold down force margin.

- The MPS3 fuel system is acceptable with respect to its ability to withstand fuel rod failure at uprated conditions. This conclusion is based on acceptable results of evaluations of rod hydriding and plenum clad support. It should be further noted that internal hydriding and clad collapse are primarily the result of manufacturing deficiencies, and are not uprate-related factors.

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[108] WCAP-15063-P-A, "Westinghouse Improved Performance Analysis and Design Model (PAD4.0)," Westinghouse Electric Corporation, July, 2000.
[109] WCAP-13589-A, "Assessment of Clad Flattening and Densification Power Spike Factor Elimination in Westinghouse Nuclear Fuel," March, 1995.

- The MPS3 fuel system is acceptable with respect to fuel coolability. This conclusion is based on the fact that the licensee demonstrated that the hydrogen pickup criterion has been met, and that the internal rod pressure acceptance criterion to prevent DNB propagation is met, which prevents fuel rod ballooning.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed SPU on the fuel system design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the fuel system and demonstrated that: (1) the fuel system will not be damaged as a result of normal operation and AOOs; (2) the fuel system damage will never be so severe as to prevent control rod insertion when it is required; (3) the number of fuel rod failures will not be underestimated for postulated accidents; and (4) coolability will always be maintained. Based on this, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of 10 CFR 50.46, GDC 10, GDC 27, and GDC 35 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the fuel system design.

2.8.2 Nuclear Design

Regulatory Evaluation

The NRC staff reviewed the nuclear design of the fuel assemblies, control systems, and reactor core to ensure that fuel design limits will not be exceeded during normal operation and anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. The NRC staff's review covered core power distribution, reactivity coefficients, reactivity control requirements and control provisions, control rod patterns and reactivity worths, criticality, burnup, and vessel irradiation. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC 11, insofar as it requires that the reactor core be designed so that the net effect of the prompt inherent nuclear feedback characteristics tends to compensate for a rapid increase in reactivity; (3) GDC 12, insofar as it requires that the reactor core be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can be reliably and readily detected and suppressed; (4) GDC 13, insofar as it requires that I&C be provided to monitor variables and systems affecting the fission process over anticipated ranges for normal operation, AOOs and accident conditions, and to maintain the variables and systems within prescribed operating ranges; (5) GDC 20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to automatically initiate operation of systems and components important to safety under accident conditions; (6) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; (7) GDC 26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; (8) GDC 27, insofar as it requires that the reactivity control systems be designed to have a

combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (9) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RVIs so as to significantly impair the capability to cool the core. Specific review criteria are contained in SRP Section 4.3 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Design changes associated with a power uprate can affect key nuclear safety parameters, such as core power distribution, reactivity coefficients, reactivity control requirements and control provisions, and reactivity worths, criticality, burnup, and vessel irradiation. Many of these parameters are used in transient and accident analyses.

The licensee evaluated the MPS3 nuclear design using core loading patterns for three cycles. These core loading patterns contain RFA/RFA-2 fuel, and represent reference cores for two transition cycles and one equilibrium cycle. The licensee stated that the loading patterns were developed based on projected energy requirements of approximately 515 effective full-power days for MPS3. As stated by the licensee, these loading patterns are not intended to represent limiting loading patterns, but were developed to demonstrate that enough margin exists between typical safety parameter values and their corresponding limits to allow flexibility in designing actual reload cores. This is illustrated in the subsequent sections that discuss the results of the licensee's transient analyses.

The following table depicts the nuclear design parameters of the uprated core in comparison to the current nuclear design. Ranges of reactivity coefficients are presented to account for the fact that the reactivity coefficients change during the life of the core. These ranges are employed in transient analyses to determine the response of the plant throughout the core life.

	Current Design Values	Uprate Analysis Values
Reactor Core Power (MWt)	3411	3650
Hot Full Power Average Coolant Temp (°F)	587.1	581.5 – 589.5, EOC 571.5
Coolant System Pressure (psia)	2250	2250
Core Average Linear Heat Rate (kW/ft)	5.45	5.83
Most Positive MTC*, <70% (pcm**/°F)	+5.0	+5.0
Most Positive MTC, >70% (pcm/°F)	0.0, linear ramp from 70% to 100% power	0.0, linear ramp from 70% to 100% power
Most Positive MDC ***	0.50	0.50, 0.45 for FWLB at HFP ARO
Doppler Temperature Coefficient	-3.20 to -0.91	-3.20 to -0.90
Doppler Only Power Coefficient	These parameters range in value. Refer to LR Table 2.8.2-1.	
Delayed Neutron Fraction	0.0040 to 0.0070	0.0040 to 0.0075
Normal Operation Enthalpy Rise Hot Channel Factor	1.70	1.65
Normal Operation Axial Peaking	2.60	2.60

* moderator temperature coefficient
** power cooling mismatch
*** moderator density coefficent

The practice of presenting evaluations of uprated cores based on projected typical values is acceptable to the staff for two reasons. First, as the licensee stated, it demonstrates that appropriate safety margins can be maintained despite the higher energy level of the uprated core. This demonstration is shown not only by a comparison of the nuclear design parameters of the current core to an uprated core, but also by acceptable transient analysis results that incorporate the nuclear design of the uprated core. Second, the actual nuclear design of the core is cycle-specific. Therefore, the licensee will continue to use the applicable NRC-approved Westinghouse design and analytical tools in accordance with the NRC-approved reload method to generate the nuclear design of each cycle.[110] In view of the typical nuclear design data presented by the licensee, and the fact that each cycle's core will be analyzed using NRC-approved methods, the NRC staff finds reasonable assurance that the MPS3 uprated core nuclear design will remain acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effect of the proposed SPU on the nuclear design of the fuel assemblies, control systems, and reactor core. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the nuclear design and has demonstrated that the fuel design limits will not be exceeded during normal or anticipated operational transients, and that the effects of postulated reactivity accidents will not cause significant damage to the RCPB or impair the capability to cool the core. Based on this evaluation and in coordination with the reviews of the fuel system design,

[110] WCAP-9273-P-A, "Westinghouse Reload Safety Evaluation Methodology," Westinghouse Electric Corporation, July, 1985

thermal and hydraulic design, and transient and accident analyses, the NRC staff concludes that the nuclear design of the fuel assemblies, control systems, and reactor core will continue to meet the applicable requirements of GDCs 10, 11, 12, 13, 20, 25, 26, 27, and 28. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the nuclear design.

2.8.3 Thermal and Hydraulic Design

Regulatory Evaluation

The NRC staff reviewed the thermal and hydraulic design of the core and the RCS to confirm that the design: (1) has been accomplished using acceptable analytical methods; (2) is equivalent to or a justified extrapolation from proven designs; (3) provides acceptable margins of safety from conditions which would lead to fuel damage during normal reactor operation and AOOs; and (4) is not susceptible to thermal-hydraulic instability. The review also covered hydraulic loads on the core and RCS components during normal operation and DBA conditions and core thermal-hydraulic stability under normal operation and anticipated transients without scram (ATWS) events. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; and (2) GDC 12, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed to assure that power oscillations, which can result in conditions exceeding SAFDLs, are not possible or can reliably and readily be detected and suppressed. Specific review criteria are contained in SRP Section 4.4 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Consistent with conventional Westinghouse design approaches, the licensee provides assurance of compliance with GDC 10 using the ANS scale of events, Conditions I through IV.[111]

For Condition I and II events, the licensee must assure that fuel damage is not expected, with the exception of a small number of fuel failures that are within the capability of the plant system to mitigate. For Condition III events, the reactor must be returned to a safe shutdown state. Although sufficient fuel damage might occur that precludes immediate resumption of operation, only a small fraction of fuel rods may be damaged. For Condition IV events, the core must remain intact with a coolable geometry.

For Condition I and II events, the design is completed to assure that there is at least a 95-percent probability with 95-percent statistical confidence that boiling transition will not occur on the limiting fuel rods. There is also at least a 95-percent probability with 95-percent confidence that the peak linear heat generating fuel rods will not exceed the uranium dioxide melting temperature.

To assure compliance with GDC 12, regarding thermo-hydro-dynamic instabilities, the licensee's core is designed such that:

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[111] American Nuclear Society ANSI N18.2-1973, "Nuclear Safety Criteria for the Design of Pressurized Water Reactor Plants", August 6, 1973.

- Fundamental MODE total power oscillations are inherently stable due to the negative power coefficient of reactivity.

- Xenon oscillations in radial, azimuthal, and diametral overtone MODES are heavily damped due to core design and the negative power coefficient of reactivity.

- First overtone MODE xenon oscillations may occur, but reactor trip functions based on axial power imbalance will assure that such oscillations do not exceed SAFDLs.

- Higher MODE xenon oscillations are heavily damped due to inherent design features and the negative Doppler coefficient of reactivity.

The licensee currently uses the Revised Thermal Design Procedure (RTDP) to analyze transient performance of departure from nucleate boiling (DNB).[112] Whereas, the licensee had previously used THINC-IV and FACTRAN[113] to evaluate transient performance, the licensee now proposes to use VIPRE and RETRAN[114]. Hence, most of the evaluations for the stretch power uprate were performed using VIPRE and RETRAN. The NRC staff discusses the acceptability of VIPRE and RETRAN, and the purposes of each, for analysis at MPS3 power uprate conditions in Section 2.8.8, "Additional Review Areas," of this safety evaluation. The NRC staff's evaluation is based on the acceptability and results of the VIPRE/RETRAN analyses.

The RTDP methodology statistically accounts for the system uncertainties in plant operating parameters, fabrication parameters, nuclear and thermal parameters, as well as the DNB correlation and computer code uncertainties. The RTDP establishes a design DNB ratio (DNBR) limit that statistically accounts for the effects of the key parameters on DNB. The RTDP is documented in WCAP-11397-P-A.[115] The DNB design criterion reflects the guidance contained in Chapter 4.4 of the SRP, specifically, that the appropriate margin is contained in the RTDP statistical analysis to provide 95/95 confidence that the limiting fuel rods will not undergo transition boiling as discussed in the preceding paragraphs. As the RTDP considers the parametric uncertainties, thermal-hydraulic analyses are performed using input parameters at their nominal values.

A safety analysis limit (SAL) DNBR is calculated, which provides for a certain amount of margin above the design limit discussed above. The SAL, which is higher than the design limit, provides a margin to offset the effect of rod bow and other DNBR penalties that may occur, as well as to provide the licensee with margin for operational flexibility.

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[112] WCAP-11397-P-A, "Revised Thermal Design Procedure," Westinghouse Electric Corporation, April, 1989
[113] WCAP-12330-A, "Improved THINC IV Modeling for PWR Design," 1989; WCAP-7908-A, "FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," Westinghouse Electric Corporation, December, 1989
[114] Sung, Y. X., et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A (Proprietary), October 1999; WCAP-14882-P-A (Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D. S. Huegel, et al, April 1999
[115] WCAP-11397-P-A, "Revised Thermal Design Procedure," Westinghouse Electric Corporation, April, 1989

The licensee is implementing the RTDP using VIPRE analyses and the WRB-2M DNB correlation,[116] which presents a slightly less conservative correlation limit based on the RFA/RFA-2 fuel. The reduced limit, 1.14, credits improvements in DNB performance due to mixing vane grid effects. The NRC staff has accepted use of the WRB-2M DNB correlation for RFA-type fuel assemblies.

Not all transients are analyzed using the WRB-2M correlation and/or the RTDP, however. For those transients where use of the WRB-2M correlation is restricted, the licensee used the Standard Thermal Design Procedure with the W-3 or WRB-2 correlation instead. These transients are those for which the analyzed conditions are predicted to fall outside the applicability range of the WRB-2M correlation based on any of pressure, local mass velocity, local quality, heated length, grid spacing, equivalent hydraulic diameter, equivalent heated hydraulic diameter, and distance from the last grid to the location of the critical heat flux (CHF). Some transients were also analyzed using the Standard Thermal Design Procedure. Any departures from the use of WRB-2M and/or the RTDP are noted in the appropriate sections of the LR, and in the staff's SE.

After setting the SAL DNBR, the licensee uses the SAL to develop core limits, axial offset limits, and dropped rod limits. The maximum enthalpy rise hot channel factor is then developed based on these limits.

Thermal-hydraulic design analysis included consideration of both thermal design and best estimate design bypass flows, which are both considered with thimble tube plugs installed and removed.

The analyses performed by Westinghouse are considered a full reference core of RFA/RFA-2 fuel. For each core design, the thermal-and hydraulic design and analysis will be performed in accordance with the NRC-approved Westinghouse reload methodology contained in WCAP-9273-P-A.[117] In accordance with this method, the safety analysis and design limit DNBRs may change to reflect the core-and-cycle specific operating conditions and transient analysis results.

The NRC staff notes that the licensee is using acceptable methods, VIPRE and RETRAN, to evaluate the thermal-hydraulic design of the core. The DNB correlations used in these analyses will be appropriate for the core conditions, or supplanted as necessary. The methods in use will account for the relevant uncertainties in an acceptable manner. Based on the results presented in the LR, and on the fact that core and cycle-specific analyses will be performed in accordance with NRC-approved methods, the staff finds this approach acceptable. Specific transients and accidents are evaluated further in Section 2.8.5 of this safety evaluation. The acceptability of the analysis methods is discussed in Section 2.8.8 of this safety evaluation.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed SPU on the thermal and hydraulic design of the core and the RCS. The NRC staff concludes that the

[116] WCAP-15025-P-A, "Modified WRB-2 Correlation, WRB-2M, for Predicting Critical Heat Flux in 17x17 Rod Bundles with Modified LPD Mixing Vane Grids," Westinghouse Electric Corporation, April, 1999

[117] WCAP-9273-P-A, "Westinghouse Reload Safety Evaluation Methodology," Westinghouse Electric Corporation, July, 1985

licensee has adequately accounted for the effects of the proposed SPU on the thermal and hydraulic design and demonstrated that the design: (1) has been accomplished using acceptable analytical methods; (2) is equivalent to or a justified extrapolation from proven designs; (3) provides acceptable margins of safety from conditions that would lead to fuel damage during normal reactor operation and AOOs; and (4) is not susceptible to thermal-hydraulic instability. The NRC staff further concludes that the licensee has adequately accounted for the effects of the proposed SPU on the hydraulic loads on the core and RCS components. Based on this, the NRC staff concludes that the thermal and hydraulic design will continue to meet the requirements of GDCs 10 and 12 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to thermal and hydraulic design.

2.8.4 Emergency Systems

2.8.4.1 Functional Design of Control Rod Drive System

Regulatory Evaluation

The NRC staff's review covered the functional performance of the control rod drive system (CRDS) to confirm that the system can affect a safe shutdown, respond within acceptable limits during AOOs, and prevent or mitigate the consequences of postulated accidents. The review also covered the CRDS cooling system to ensure that it will continue to meet its design requirements. The NRC's acceptance criteria are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents; (2) GDC 23, insofar as it requires that the protection system be designed to fail into a safe state; (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems; (4) GDC 26, insofar as it requires that two independent reactivity control systems be provided, with both systems capable of reliably controlling the rate of reactivity changes resulting from planned, normal power changes; (5) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (6) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RVIs so as to significantly impair the capability to cool the core; and (7) GDC 29, insofar as it requires that the protection and reactivity control systems be designed to assure an extremely high probability of accomplishing their safety functions in event of AOOs. Specific review criteria are contained in SRP Section 4.6.

Technical Evaluation

The CRDS consists of the CRDMs, the Rod Control System, and the Reactor Trip Switchgear. Essential elements of the CRDS are isolated from the non-essential elements (the Rod Control System). The CRDM has a cooling system that is designed for reactor vessel head and coolant heat removal to reduce thermal aging effects on the insulation and potting materials used in the CRDMs.

The CRDMs are located on the dome of the reactor vessel head. They are coupled to RCCAs, which have neutron absorber material over the entire length of the control rods. The primary function of the CRDM is to insert, withdraw, or hold stationary, RCCAs within the core to control core average temperature and to shut down the reactor.

The drive mechanism is a magnetically operated jack. It consists of three electromagnetic coils, which are energized and de-energized in specific sequences that withdraw or insert the rods in discrete steps. An interruption of electric power de-energizes all three coils, and results in the rods falling rapidly into the core. Interrupting the power to the coils achieves a reactor trip.

The requested SPU could potentially affect the CRDS due to the temperature effects of increasing core thermal power from 3411 MWt to 3650 MWt. The licensee stated that the temperature of the reactor vessel head is the same as the reactor vessel inlet temperature, and that the uprated full power reactor vessel inlet temperature increases from 555.9 ºF to 556.4 ºF. The evaluated cases for both CLTP and for the uprated power level, however, use the zero load temperature, 557ºF, as the maximum reactor vessel inlet temperature.

As a result, the licensee concluded that there are no physical changes required to the CRDS, operating coil stacks, power supplies, solid state electronic control cabinets, or the control rod drive cooling system. There are also no physical changes to the fuel system design that would affect the CRDS.[118]

Control insertion times are verified after each RFO to be with in the technical specification limit, providing reasonable assurance that any impact on the control insertion times would be identified before operation [119]

Based on the NRC staff's review of the functional design of the CRDS, the staff concludes that the CRDS will operate acceptably at uprated conditions. The NRC staff based its conclusion on: (1) the fact that CRDS evaluations are performed at a temperature that is bounding of the vessel head temperature; (2) the fact that no physical changes are required to the CRDS; and (3) the fact that the MPS3 TS-required verification of control insertion times will provide additional verification of CRDS operability at uprated conditions prior to operation.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed SPU on the functional design of the CRDS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the system and demonstrated that the system's ability to affect a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of postulated accidents will be maintained following the implementation of the proposed SPU. The NRC staff further concludes that the licensee has demonstrated that sufficient cooling exists to ensure the system's design bases will continue to

[118] Serial No.: 07-0834G, "Dominion Nuclear Connecticut, Inc., Millstone Power Station Unit 3 Response To Request For Additional Information Regarding Stretch Power Uprate License Amendment Request Response To Questions SRXB-07-0013 Through SRXB-07-0047", Millstone Generation, January 11, 2008 (ADAMS Accession No. ML080580476)

[119] Technical Specifications for Millstone Power Station, Unit 3

be followed upon implementation of the proposed SPU. Based on this, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of GDCs 4, 23, 25, 26, 27, 28, and 29 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the functional design of the CRDS.

2.8.4.2 Overpressure Protection During Power Operation

Regulatory Evaluation

Overpressure protection for the RCPB during power operation is provided by relief and safety valves and the RPS. The NRC staff's review covered pressurizer relief and safety valves and the piping from these valves to the quench tank and RCS relief and safety valves. The NRC's acceptance criteria are based on: (1) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (2) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and that the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Overpressure protection for the RCPB during power operation is important for the following AOOs:

(1) Loss of electrical load and/or turbine trip (TT);

(2) Uncontrolled RWAP;

(3) Loss of reactor coolant flow;

(4) Loss of normal feedwater; and

(5) Loss of offsite power to the station auxiliaries

The first event, loss of electrical load and/or turbine trip, is the most limiting AOO with respect to the potential for overpressurization of the RCPB.

According to SRP Section 5.2.2, it is necessary to demonstrate that the MPS3 safety valve capacities continue to be sufficient to limit RCS pressure to less than 110% of the RCPB design pressure (as specified by the ASME Code)[120] during the most limiting AOO, assuming the effective reactor scram is derived from the second safety grade signal from the RPS. For this purpose, the licensee refers to analysis results that are provided in LR Subsection 2.8.5.2.1, "Loss of External Electrical Load, Turbine Trip, Steam Pressure Regulator Failure, and Loss of Condenser Vacuum [LOCV]." However, the analysis of LR 2.8.5.2.1 would be performed assuming the first RPS-generated reactor trip.

[120] ASME Boiler and Pressure Vessel Code, Section III, "Nuclear Power Plant Components," Article NB-7000, "Protection Against Overpressure," American Society of Mechanical Engineers

Upon request from the NRC staff, the licensee has provided the results[121] for the loss of external electrical load/TT analysis, in which the reactor is assumed to trip from the second safety-grade reactor trip signal (SRP 5.2.2 II.3.B.iii). In this case, the first reactor trip signal is generated by high pressurizer pressure, at 6.2 seconds. As pressure continues to increase, the PSV setpoint is reached 2 seconds later. The RCS pressure peak, 2747 psia, occurs at 11.8 seconds. The credited reactor trip signal, from OTΔT, is generated at 12.8 seconds.

For comparison, crediting the first reactor trip signal, as in the LOL/TT analysis of LR Section 2.8.5.2.1, yields a lower maximum RCS pressure (2729.4 psia).

The licensee has demonstrated that limiting overpressure at power AOO, the LOL/TT, would not produce a maximum RCS pressure that exceeds 110% of the RCS design pressure (2750 psia, even if the first reactor trip signal is not credited.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed SPU on the overpressure protection capability of the plant during power operation. The NRC staff concludes that the licensee has: (1) adequately accounted for the effects of the proposed SPU on pressurization events and overpressure protection features; and (2) demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Based on this, the NRC staff concludes that the overpressure protection features will continue to provide adequate protection to meet GDC 15 and GDC 31 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to overpressure protection during power operation.

2.8.4.3 Overpressure Protection During Low Temperature Operation

Regulatory Evaluation

Overpressure protection for the RCPB during low temperature operation of the plant is provided by pressure-relieving systems that function during the low temperature operation. The NRC staff's review covered relief valves with piping to the quench tank, the makeup and letdown system, and the RHR system, which may be operating when the primary system is water solid. The NRC's acceptance criteria are based on: (1) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (2) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that it behaves in a nonbrittle manner and the probability of rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 5.2.2.

[121] Serial No.: 07-0834G, "Dominion Nuclear Connecticut, Inc., Millstone Power Station Unit 3 Response To Request For Additional Information Regarding Stretch Power Uprate License Amendment Request Response To Questions SRXB-07-0013 Through SRXB-07-0047", Millstone Generation, January 11, 2008 (ADAMS Accession No. ML080580476)

Technical Evaluation

The staff's evaluation of the PT limit curves is addressed in 2.1.2.2 of this SE; the staff's evaluation of PTS is evaluated in Section 2.1.3 of this SE. The licensee concluded that no change to the PT limit curves was necessary, and that the current cold overpressurization analysis remains bounding. As a result, the licensee concluded that the Low Temperature Overpressure Protection setpoint need not change. Based on the staff's acceptable findings of the PTS evaluations and the PT limit curves in Section 2.1 of this SE, the staff finds the licensee's conclusions acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed SPU on the overpressure protection capability of the plant during low temperature operation. The NRC staff concludes that the licensee has: (1) adequately accounted for the effects of the proposed SPU on pressurization events and overpressure protection features; and (2) demonstrated that the plant will continue to have sufficient pressure relief capacity to ensure that pressure limits are not exceeded. Based on this, the NRC staff concludes that the low temperature overpressure protection features will continue to provide adequate protection to meet GDC 15 and GDC 31 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to overpressure protection during low temperature operation.

2.8.4.4 Residual Heat Removal System

Regulatory Evaluation

The RHR system is used to cool down the RCS following shutdown. The RHR system is typically a low pressure system which takes over the shutdown cooling function when the RCS temperature is reduced. The NRC staff's review covered the effect of the proposed SPU on the functional capability of the RHR system to cool the RCS following shutdown and provide decay heat removal. The NRC's acceptance criteria are based on: (1) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects; (2) GDC 5, insofar as it requires that SSCs important to safety not be shared among nuclear power units unless it can be shown that sharing will not significantly impair their ability to perform their safety functions; and (3) GDC 34, which specifies requirements for an RHR system. Specific review criteria are contained in SRP Section 5.4.7 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The RHRS, in conjunction with the steam and power conversion system, is designed to transfer the fission product decay heat and other residual heat from the reactor core within acceptable limits. The transfer of the heat removal function from the steam and power conversion system to the RHR system occurs when the RCS is at approximately 350 °F and 375 psig.

Residual heat removal is not the only design function of the RHRS. Portions of the RHRS support ECCS design functions. During plant cooldown, a portion of the RCS flow is diverted to the CVCS for RCS purification and inventory/pressure control. The RHR pumps, however, do not support containment heat removal or the ECCS sump recirculation phase.

The RHRS is comprised of two RHR pumps, two heat exchangers, and associated piping, cabling, and electric power sources, as described in MPS3 UFSAR Section 5.4.7. It contains suitable redundancy to perform its function with a single active component failure, because once the RCS conditions allow the RHRS to be placed in service, the remaining cooldown can be accomplished with either one or two trains of RHR in service. The consequence of cooling down with a single RHRS train in service is a longer cool down time, and the uprate will not affect this function. Therefore, the NRC staff finds the proposed uprate acceptable with respect to the ability of the RHRS to withstand a single failure at uprated conditions.

Because of the higher energy design of the uprated core, the proposed power uprate will result in an increased decay heat load. The RHRS cooldown times could therefore be extended, but the licensee has changed the design of the CCWS so that cooldown operation temperatures are higher. The licensee stated that this design change will offset impacts on cooldown times.

The staff requested that the licensee confirm that the design changes made to the RHRS heat exchangers that permit warmer CCW return flows remain within the design capability of the RHRS heat exchangers. The licensee responded by letter dated January 11, 2008, stating that the peak shell side design temperature of the RHRS heat exchanger is 200 ºF, which is well over the newly proposed CCW return line 145 ºF operating temperature.[122] The staff finds, therefore, that the proposed design change to the RHRS that will permit decay heat removal of the uprated core in similar times to that at the CLTP level are acceptable.

Functionally, the RHRS will be placed in service once the RCS temperature is reduced from its no-load value, 557 ºF, to RHRS entry conditions, 350 ºF. The licensee stated that, for normal cooldown, this evolution will take place within 4-hours. With two RHRS heat exchangers and pumps in service, the RCS temperature can be reduced from 350 ºF to 200 ºF within 20 hours, which will provide the licensee with the capability to reach cold shutdown conditions 24 hours after reactor shutdown.

With one RHRS heat exchanger and pump aligned for ECCS operation for cooldown to a 260 ºF RCS temperature, the RHRS will cool the RCS from 350 ºF to 200 ºF in 60 hours with one reactor coolant pump operating.

The MPS3 safety-grade cold shutdown analysis is based on taking the plant from normal operating conditions to cold shutdown in a reasonable time period following a safe-shutdown earthquake, coincident with a LOOP and a safety-related electrical distribution system train failure.[123] This coincidence of events will disable, according to the licensee, multiple safe shutdown components, including an RHRS train. The safety-grade cold shutdown event results in a natural circulation cooldown.

The current licensing basis for safety-grade cold shutdown at MPS3 requires that the RHRS be placed in service within 36 hours following event initiation. The plant is then cooled to cold shutdown conditions in an additional 30 hours, for a total time of 66 hours. BTP 5-4, “Design

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[122] Serial No.: 07-0834G, “Dominion Nuclear Connecticut, Inc., Millstone Power Station Unit 3 Response To Request For Additional Information Regarding Stretch Power Uprate License Amendment Request Response To Questions SRXB-07-0013 Through SRXB-07-0047", Millstone Generation, January 11, 2008 (ADAMS Accession No. ML080580476)

[123] NUREG-0800, “Standard Review Plan”, Revision 3, March 2007 (ADAMS Accession No. ML070710376)

Requirements for the Residual Heat Removal," specifies that "the [RHR] system(s) shall be capable of bringing the reactor to a cold shutdown condition, with only offsite or onsite power available, within a reasonable period of time following shutdown, assuming the most limiting single failure." Therefore, the 66-hour period of time to safety-grade cold shutdown is a part of the licensing basis at MPS3. For operation at power uprate, this period of time is extended to 72 hours.

Because there is no increase in cooldown time for normal RHRS cooldown, the NRC staff requested additional information regarding differences in the normal and safety-grade cold shutdown analyses from pre- to post-uprate implementation. Prior to the uprate, both analyses assumed a decay heat model that included uncertainties. For uprate analyses, however, the normal cooldown analysis returns to an evaluation technique that does not include decay heat uncertainty. The licensee indicated that the analysis remains conservative and listed additional conservatism in the analysis. Also, the normal cooldown analysis is a functional analysis. The safety-grade cold shutdown analysis analysis, however, retains decay heat model uncertainties. The prior analysis assumed a 140 ºF CCW RHR HX outlet temperature, and the functional analysis assumed a 130 ºF CCW RHR HX outlet temperature. For uprate analyses, both the functional and the safety-grade cold shutdown analyses assume a 145 ºF CCW RHR HX outlet temperature.

Based on these differences, the NRC staff finds that the extension of the licensing basis safety-grade cold shutdown time remains, to a reasonable extent, consistent with the functional analysis, and acceptable for uprated operations. The NRC staff observed that other PWR licensees have longer safety-grade cold shutdown cooldown times, such that the power uprate safety-grade cold shutdown cooldown time at MPS3 remains consistent with current operations at other facilities. Therefore, the staff finds that the safety-grade cold shutdown shutdown time extension from 66 to 72 hours is acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed SPU on the RHR system. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed SPU on the system and demonstrated that the RHR system will maintain its ability to cool the RCS following shutdown and provide decay heat removal. Based on this, the NRC staff concludes that the RHR system will continue to meet the requirements of GDCs 4, 5, and 34 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the RHR system.

2.8.5 Accident and Transient Analyses

2.8.5.1. Increase in Heat Removal by the Secondary System

2.8.5.1.1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Steam Generator Relief or Safety Valve

Regulatory Evaluation

Excessive heat removal causes a decrease in moderator temperature which increases core reactivity and can lead to a power level increase and a decrease in shutdown margin (SDM).

Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered: (1) postulated initial core and reactor conditions; (2) methods of thermal and hydraulic analyses; (3) the sequence of events; (4) assumed reactions of reactor system components; (5) functional and operational characteristics of the RPS; (6) operator actions; and (7) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; (3) GDC 20, insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded during any condition of normal operation, including AOOs; and (4) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.1.1-4 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Decrease in Feedwater Temperature, Increase in Feedwater Flow

A change in SG feedwater conditions that results in an increase in feedwater flow or a decrease in feedwater temperature could result in excessive heat removal from the RCS. Such changes in feedwater flow or feedwater temperature are a result of a failure of a feedwater control valve or feedwater bypass valve, failure in the feedwater control system, or operator error. Excessive heat removal causes a decrease in moderator temperature that increases core reactivity and can lead to an increase in power level. Any unplanned power level increase may result in fuel damage or excessive reactor system pressure. The RPS and safety systems are actuated to mitigate the transient.

The acceptance criteria are based on CHF not being exceeded, pressure in the RCS and MSS being maintained below 110 percent of the design pressures, and the peak linear heat generation rate not exceeding a value that would cause fuel centerline melt. Demonstrating that CHF is not exceeded, and fuel cladding integrity is maintained, is accomplished by ensuring that the minimum departure from nucleate boiling ratio (DNBR) remains greater than the 95/95 DNBR SAL in the limiting fuel rods. Specific review criteria are found in SRP Section 15.1.1-4.

The licensee used the NRC-approved RETRAN computer code to analyze the RCS and core response to the excessive heat removal due to a feedwater system malfunction, given the power uprate conditions.[124] DNBR evaluations were performed with the NRC-approved RTDP.[125]

[124] WCAP-14882-P-A (Proprietary), RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses, D.S. Huegel, et al, April 1999
[125] WCAP-11397-P-A, "Revised Thermal Design Procedure," Westinghouse Electric Corporation, April, 1989

Reduction in feedwater temperature

Reducing feedwater temperature when the plant is operating at full, uprated power would add less positive reactivity to the core than would the increase in secondary steam flow events, which are evaluated against AOO acceptance criteria contained in LR Section 2.8.5.1.1.2.3. Therefore, the licensee has not provided analyses of any feedwater system malfunctions that result in a reduced feedwater temperature. The NRC staff finds this approach to be reasonable and expected.

Increase in feedwater flow

The increase in feedwater flow cases were considered at hot zero power (HZP), as well as at hot full power (HFP). At HZP, the core cooldown produced by the increase in feedwater flow is exceeded by the core cooldown produced by a steam system piping failure (also considered at HZP). Therefore, the licensee concluded that this case is bounded by a steam system piping failure. The NRC staff agrees.

At HFP, the licensee analyzed cases assuming failure of the feedwater control valve in one and two feedwater supply loops, with and without automatic rod control. The increase in feedwater flow case that assumed failure of the feedwater control valve in all feedwater supply loops, without automatic rod control, was presented, yielding a minimum DNBR of 1.88. The results indicate the reactor is tripped from the TT signal. This can be problematic, since the reactor trip from TT is not considered to be as reliable as other reactor trip signals. The TT signal originates in the turbine building, which is not seismically qualified. However, the NRC staff does not consider the reactor trip to be the direct mitigation for this increase in feedwater flow event, especially since the minimum DNBR occurs only 0.1 seconds after rod motion is begun. The time of minimum DNBR is apparently linked to the effect of the RCS pressure spike that results from the turbine trip.

With no credit for the reactor trip on turbine trip, the feedwater isolation function, which is actuated from the SG high level signal, not the TT signal, ends the positive reactivity insertion and power increase. The event then becomes a total loss of feedwater, initiated at a power level, and shell-side SG water inventory higher-than-nominal. RCS temperature would rise, due to the lack of feedwater flow, until the reactor is tripped by the OTΔT reactor trip signal. Since the OTΔT reactor trip setpoint is calculated to prevent DNBR from falling to the DNBR SAL (see LR Figure 2.8.5.0-1), the minimum DNBR would remain greater than the DNBR SAL. Therefore, the NRC staff finds these results to be acceptable, despite the modeling of reactor trip on TT in the analysis.

The NRC staff reviewed the licensee's analysis and concluded that the licensee's analysis was performed using acceptable analytical models. The staff found that the licensee demonstrated that the RPS and safety systems will continue to assure the CHF will not be exceeded and pressures in the RCS and MSS will be maintained below 110 percent of their respective design pressures. The staff concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed power uprate program. Therefore, the staff found the proposed power uprate program acceptable with respect to the excessive heat removal due to feedwater system malfunction event.

Increase in Steam Flow and Inadvertent Opening of a Steam Generator Relief or Safety Valve

Increase in steam flow and inadvertent opening of a steam generator relief or safety valve are excessive load increase incidents. They are AOOs that are characterized by a rapid increase in the steam flow to a level beyond that which is needed to match the reactor core power generation. As a result, the core is cooled, and reactivity and power increase to match the higher steam flow. The acceptance criteria are based on CHF not being exceeded, pressure in the RCS and MSS being maintained below 110 percent of the design pressures, and the peak linear heat generation rate not exceeding a value that would cause fuel centerline melt. It is also important to prevent AOOs from developing into postulated accidents without the occurrence of other, independent failures.[126] Specific review criteria are found in SRP Section 15.1.1-4.

The increase in steam flow event, or excessive load increase event, is considered as a 10 percent step-load increase at HFP. This event could be caused by an operator error, or an equipment malfunction in the steam dump control or turbine speed control. The plant design can tolerate a 10 percent step-load increase or a 5 percent per minute ramp load increase in the range of 15 to 100 percent of full power without tripping. Higher load increases or higher rates of load increase could lead to a reactor trip. The LR refers to the analysis of UFSAR Section 15.1.3.3, which indicates that a 10 percent load increase would cause reactor power to increase and stabilize at a higher power level. No reactor trip would be demanded. No analysis is necessary to demonstrate that the minimum DNBR would remain above the DNBR SAL of 1.60, even at power uprate conditions. This is verified by consulting LR Figure 2.8.5.0-1, Illustration of OTΔT and OPΔT Protection.[127] In this figure, increasing rated thermal power from 1.0 to 1.1, at the maximum value of nominal core inlet temperature of 556.4 ºF (from LR Table 1-1), would not cross either of the OTΔT or OPΔT protection lines. Since the OTΔT protection line causes a reactor trip before the core thermal conditions can reach the DNBR SAL, and the OPΔT protection line prevents the linear heat rate from exceeding its SAL, the NRC staff concludes that the proposed power uprate is acceptable with respect to the excessive load increase incident.

Conclusion

The NRC staff has reviewed the licensee's analyses of the excess heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and was performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, 20, and 26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the events stated.

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[126] American Nuclear Society ANSI N18.2-1973, "Nuclear Safety Criteria for the Design of Pressurized Water Reactor Plants", August 6, 1973

[127] Serial No.: 07-0450, "Dominion Nuclear Connecticut. Inc., Millstone Power Station Unit 3, License Amendment Request, Stretch Power Uprate", Dominion Generation, July 13, 2007 (ADAMS Accession No. ML072000386)

2.8.5.1.2 Steam System Piping Failures Inside and Outside Containment

Regulatory Evaluation

The steam release resulting from a rupture of a main steam pipe will result in an increase in steam flow, a reduction of coolant temperature and pressure, and an increase in core reactivity. The core reactivity increase may cause a power level increase and a decrease in SDM. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered: (1) postulated initial core and reactor conditions; (2) methods of thermal and hydraulic analyses; (3) the sequence of events; (4) assumed responses of the reactor coolant and auxiliary systems; (5) functional and operational characteristics of the RPS; (6) operator actions; (7) core power excursion due to power demand created by excessive steam flow; (8) variables influencing neutronics; and (9) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (2) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RVIs so as to significantly impair the capability to cool the core; (3) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and (4) GDC 35, insofar as it requires the reactor cooling system and associated auxiliaries be designed to provide abundant emergency core cooling. Specific review criteria are contained in SRP Section 15.1.5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Steam System Piping Failures at Hot Zero Power (HZP)

The licensee used the RETRAN[128] computer code to simulate the NSSS response to the HZP MSLB transient and to provide dynamic core conditions to the VIPRE[129] thermal-hydraulic code. The VIPRE code, employing the W-3 correlation (due to local conditions outside the WRB-2M applicability range), was used to calculate the DNBR at the limiting time during the transient These computer models and methods have been previously reviewed and approved by the NRC staff for the MSLB analysis.

HZP conditions were modeled with four loops in service, and an available SDM of 1.3 percent $\Delta k/k$. All control rod assemblies were assumed to be inserted, except the most reactive control rod assembly, which was assumed to be stuck in its fully withdrawn position. In the event of a return to criticality, the highest hot channel factors would be found in the region of this stuck control rod assembly.

[128] WCAP-14882-P-A (Proprietary), "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," D.S. Huegel, et al, April 1999

[129] Sung, Y. X., et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A (Proprietary), October 1999

The largest possible, effective steam line break size is 1.388 ft^2, the area of the flow restrictors in the steam exit nozzles of the Model F SGs. The licensee assumed a break size of 1.4 ft^2, and analyzed cases assuming that offsite power is, and is not available, and that there are no plugged tubes in the SGs (to maximize the core cooldown rate).

The LR states that, "Only the two-out-of-four pressurizer low-pressure signal is credited for safety injection actuation." Although, the sequence of events (LR Table 2.8.5.1.2.2.1-1)[130] lists low steam line pressure as the first safety injection signal, at 0.5 seconds, the analysis does not credit the initiation of SI flow until 72.8 seconds, 47 seconds after the SI signal from low pressurizer pressure is generated at 25.8 seconds. This is expected for a large steam line break, since it is the direct result of the event.

Although the safety injection system is actuated early in the transient (72.8 seconds), the minimum DNBR is not reached until about 5 minutes later, as the SG is emptying and the core cooldown is ending. The limiting MPS3 HZP MSLB case demonstrates that the calculated minimum DNBR (1.77) remains above the DNB SAL of 1.45, ensuring that fuel clad failure does not occur.

Based upon the input parameters, assumptions, and modeling techniques described in LR Section 2.8.5.1.2.2.1, the NRC staff finds that the HZP MSLB transient simulation and the identification of the limiting cases are acceptable.

Steam System Piping Failures at Hot Full Power

The purpose of the HFP MSLB (or pre-trip MSLB) analysis is to demonstrate that core protection is maintained (i.e., the linear heat generation rate does not exceed the safety limit) prior to and immediately following a reactor trip. After reactor trip, the HZP MSLB (above) analyses are applied to demonstrate that the minimum DNBR remains higher than the safety limit.

The current licensing basis for the MPS3 unit does not include a specific assessment of the pre-trip power excursion portion of the MSLB event. The MPS3 UFSAR focuses solely on the post-trip return-to-power event. This departure from the current licensing basis was necessary to properly assess the potential radiological consequences resulting from the challenge to the fuel design limits experienced during the initial power excursion.

The licensee also used the RETRAN code to simulate the NSSS response to the HFP MSLB transient and to provide dynamic core conditions to the VIPRE thermal-hydraulic code. The VIPRE computer code, employing the WRB-2M correlation above the first mixing vane grid and the W-3 correlation below, was used to calculate the minimum DNBR during the transient.

LR Section 2.8.5.1.2 describes the input parameters and assumptions used in the MSLB analyses. Tables 2.8.5.1.2.2.2-1 and 2.8.5.1.2.2.2-2 list the sequence of events and describe the analyzed cases of the limiting pre-trip MSLB scenarios for MPS3. The limiting break size is 0.86 ft^2, since it produces the highest peak heat flux. An HFP, MSLB of this size leads to a

[130] Serial No.: 07-0450, "Dominion Nuclear Connecticut. Inc., Millstone Power Station Unit 3, License Amendment Request, Stretch Power Uprate", Dominion Generation, July 13, 2007 (ADAMS Accession No. ML072000386)

reactor trip on the OPΔT trip signal. Larger break sizes lead to reactor trip from the low steamline pressure safety injection signal, and smaller break sizes might not demand a reactor trip.

The limiting case results in a minimum DNBR of 2.068, which exceeds the DNBR SAL of 1.60, and a peak linear heat rate of 21.0 kW/ft, which is less than the peak linear heat rate SAL of 22.6 kW/ft.

The limiting MPS3 pre-trip MSLB cases demonstrate that the calculated minimum DNBR remains above the DNB SAFDL, and the peak linear heat rate remains below the peak linear heat rate SAL, thus ensuring that fuel rod failure does not occur.

Conclusion

The NRC staff has reviewed the licensee's analyses of steam system piping failure events and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of a propagating fracture of the RCPB is minimized, and abundant core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 27, 28, 31, and 35 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to steam system piping failures.

2.8.5.2 Decrease in Heat Removal By the Secondary System

2.8.5.2.1 Loss of External Load, Turbine Trip, Loss of Condenser Vacuum, and Steam Pressure Regulatory Failure.

Regulatory Evaluation

A number of initiating events may result in unplanned decreases in heat removal by the secondary system. These events result in a sudden reduction in steam flow and, consequently, result in pressurization events. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered the sequence of events, the analytical models used for analyses, the values of parameters used in the analytical models, and the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.1-5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

A major loss of load (LOL) can result from either a loss-of-external electrical load or from a TT from full power without a direct reactor trip. These events result in a sudden reduction in steam flow. The loss of heat sink leads to pressurization of the RCS and MSS. The AOO acceptance criteria applicable to this event are that: (1) CHF is not exceeded; (2) pressure in the RCS and MSS are maintained below 110 percent of the design pressures values; and (3) the event does not develop into a more serious plant condition without the occurrence of another, independent fault. Specific review criteria are found in SRP Section 15.2.1-5.

The NRC staff agrees that the limiting loss of heat sink event is the TT or the LOCV (which leads to a turbine trip). These events are very similar, since their analyses share two key assumptions: no direct reactor trip on turbine trip, and no steam dumping to the condenser. If steam dumping to the condenser is not available, then the steam is relieved through the MSSVs. For this event, the reactor can be tripped by the high pressurizer pressure signal, the low-low SG water level signal, the OTΔT signal, or the OPΔT signal.

The licensee analyzed three cases for a complete LOL from full power at power uprate conditions: (1) with pressure control; (2) with automatic pressure control and minimum SG tube plugging; and (3) without automatic pressure control and maximum SG tube plugging.

Case (1) assumes the operation of pressurizer sprays and pressurizer PORVs. This tends to limit the RCS pressurization, delay reactor trip from the high pressurizer pressure signal, and thereby reduce the resultant DNBR. Case (1), therefore, is analyzed to evaluate the minimum DNBR that could be generated by this event. The RTDP is applied in this analysis. Case (1), therefore, is also analyzed to verify that the event could not become a small break LOCA, by filling the pressurizer, discharging water through the PORVs and causing a PORV to stick open. For MPS3, the PORV is less likely to stick open, since it's qualified for water relief. Therefore, the pressurizer PORVs, if opened can be expected to reseat completely, even after they discharge water.

Case (2) assumes the operation of pressurizer sprays and pressurizer PORVs, and a minimum level of SG tube plugging. This tends to limit the RCS pressurization, delay reactor trip from the high pressurizer pressure signal, and increase primary to secondary heat transfer rate; and thereby increase SG shell-side pressure. Case (2), therefore, is analyzed to evaluate the maximum MSS pressure that could be generated by this event. RTDP conditions are not applied in this analysis.

Case (3) does not assume the operation of pressurizer sprays and pressurizer PORVs; but does assume a maximum level of SG tube plugging. This tends to reduce primary to secondary heat transfer rate, and thereby increase RCS pressure. Case (3), therefore, is analyzed to evaluate the maximum RCS pressure that could be generated by this event, and test the relief capacity of the PSVs. RTDP conditions are not applied in this analysis.

Case (1), performed for DNBR evaluation, yielded a minimum DNBR of 2.10 (from LR Table 2.8.5.2.1-2), and this value meets the DNBR SAL of 1.60. The reactor trip was demanded by the high pressurizer pressure trip signal, and the minimum DNBR occurred as the rods were falling into the core. If the high pressurizer pressure trip signal had not been generated first, it is

expected that the OTΔT trip signal would have been generated, as the core heated up and the DNBR approached the DNBR SAL. LR Figure 2.8.5.2.1-2 indicates that the peak pressurizer water volume attained (about 1600 ft^3) would not be sufficient to fill the pressurizer to capacity (about 1800 ft^3). Therefore, this event would not develop into a more serious event, by causing a PORV to stick open.

Case (2), performed to calculate the maximum MSS pressure, yielded a peak MSS pressure of 1302.25 psia, which is below steam system pressure SAL (110 percent of the design value or 1320 psia). The reactor trip was also demanded by the high pressurizer pressure trip signal, and the peak MSS pressure occurred shortly after the rods had been fully inserted into the core.

Case (3), performed to calculate the maximum RCS pressure, yielded a peak RCS pressure of 2729.41 psia, which is below RCS pressure SAL (110 percent of the design value of 2750 psia). The reactor trip was demanded by the high pressurizer pressure trip signal, and the peak RCS pressure occurred as the rods were falling into the core.

The NRC staff reviewed the licensee's analyses of the loss of external electric load and concluded that the licensee's analyses were performed using acceptable analytical models. The staff found the licensee demonstrated the minimum DNBR will remain above the SAL and pressures in the RCS and MSS will remain below 110 percent of their respective design pressure values for the proposed power uprate. The staff concluded that the MPS3 loss of external electric load/ TT analyses at power uprate conditions show that MPS3 will continue to meet applicable regulatory requirements following implementation of the power uprate. Therefore, the staff found the proposed power uprate program acceptable with respect to the loss of external electrical load event.

Conclusion

The NRC staff has reviewed the licensee's analyses of the decrease in heat removal events described above and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of these events. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the events stated.

2.8.5.2.2 Loss-of-Non-emergency AC Power to the Station Auxiliaries

Regulatory Evaluation

The loss-of-non-emergency ac power is assumed to result in the loss of all power to the station auxiliaries and the simultaneous tripping of all reactor coolant circulation pumps. This causes a flow coastdown as well as a decrease in heat removal by the secondary system, a turbine trip, an increase in pressure and temperature of the coolant, and a reactor trip. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered: (1) the sequence of events; (2) the analytical model used for analyses; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The

NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.6 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The loss-of-non-emergency ac power, an AOO, cuts off all power to the station auxiliaries and trips all RCPs). The reactor and turbine trip, the RCPs coast down, reactor coolant pressure and temperature rise, and heat removal by the secondary system decreases. Following the RCP trip, the reactor coolant flow necessary to remove residual heat is provided by natural circulation, which is driven by the secondary system and the AFW system. The RPS generates the actuation signals needed to mitigate the transient. The AOO acceptance criteria applicable to this event are that: (1) CHF is not exceeded, (2) pressure in the RCS and MSS are maintained below 110 percent of the design pressures values, and (3) the event does not develop into a more serious plant condition without the occurrence of another, independent fault. Specific review criteria are found in SRP Section 15.2.6.

Analyses for the loss-of-non-emergency ac power event are not reported in the LR, since this event is bounded by:

(1) the complete loss-of-flow event, LR Section 2.8.5.3, with respect to the DNBR SAL;

(2) the LOL/TT event, LR Section 2.8.5.2.1, with respect to RCS pressure and MSS pressure SALs; and

(3) the LONF event with loss-of-non-emergency ac power, LR Section 2.8.5.2.3, with respect to the capabilities of RCS natural circulation and the AFWS to remove stored and residual heat.

The LONF event with loss-of-non-emergency ac power analysis also demonstrates that a more serious plant condition cannot develop from this event, since the results do not indicate the pressurizer would become water-solid.

The NRC staff agrees with this approach, since it is consistent with the results of the aforementioned analyses in this LR, and with results of analyses for these events that have been performed for other, similarly designed plants.

The NRC staff concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed power uprate, with respect to the loss-of-non-emergency ac power to the plant auxiliaries.

Conclusion

The NRC staff has reviewed the licensee's discussion of the loss-of-non-emergency ac power to station auxiliaries event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the loss-of-non-emergency ac power to station auxiliaries event.

2.8.5.2.3 Loss of Normal Feedwater Flow

Regulatory Evaluation

A LONF flow could occur from pump failures, valve malfunctions, or a LOOP. Loss of feedwater flow results in an increase in reactor coolant temperature and pressure which eventually requires a reactor trip to prevent fuel damage. Decay heat must be transferred from fuel following a LONF flow. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient. The NRC staff's review covered: (1) the sequence of events; (2) the analytical model used for analyses; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.2.7 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The LONF flow, an AOO, results in a reduction in capability of the secondary system to remove heat from the primary side. The loss of heat sink requires the reactor trip and an alternate supply of feedwater be supplied to the SGs. Following the reactor trip, it is necessary to remove residual heat and RCP heat to prevent RCS pressurization and loss of primary system water inventory through the pressurizer relief and safety valves. If enough RCS inventory is lost, then core damage could occur. Since the reactor is tripped before the SG heat transfer capability is reduced, the primary system conditions never approach those that would result in a violation of the limit DNBR. The RPS provides the protection against a LONF flow event via a reactor trip on SG low-low water level in one or more SGs. The AFW system starts automatically on SG low-low water level. The two motor driven AFW pupms start automatically following an SI, LOOP, or on trip of all main feedwater pumps.

The LR (Section 2.8.5.2.3) also indicates the AFW system will be started by the anticipated transient without SCRAM (ATWS) mitigation system actuation circuitry (AMSAC) actuation signal. The staff notes that, while AMSAC would be available for AFW actuation, crediting its operation in an LONF flow analysis could be problematic. Although the ATWS Rule (10 CFR 50.62) requires the AMSAC to be reliable, it does not require AMSAC to be safety-grade. AMSAC is not credited in the licensee's analyses.

The LONF flow analysis demonstrates that following a LONF flow, the AFW system is capable of removing stored and residual heat, thus preventing overpressurization of the RCS, overpressurization of the secondary side, water relief from the pressurizer and uncovery of the reactor core.

The AOO acceptance criteria applicable to this event are that: (1) CHF is not exceeded; (2) pressure in the RCS and MSS are maintained below 110 percent of the design pressures values; and (3) the event does not develop into a more serious plant condition without the occurrence of another, independent fault. Specific review criteria are found in SRP Section 15.2.7.

The LONF flow transient was analyzed using the RETRAN computer code, at 102 percent of uprated conditions. LONF flow events with and without offsite power were considered. RCP heats of 20 MWt and 16 MWt were modeled in the cases with and without offsite power, respectively. The SG low-low water level reactor trip setpoint was assumed to be set at 0 percent of narrow range span (NRS). A conservatively high core residual heat generation rate was assumed, based on the ANS 5.1-1979 Decay Heat model, +2σ for uncertainties.[131] SG tube plugging levels of both 0 percent and 10 percent were considered. AFW system flow, from both motor-driven AFW pumps, was assumed to begin 60 seconds after the SG low-low water level setpoint was reached, and this flow was split equally among the four SGs. The worst single failure modeled was the loss of the turbine driven AFW pump.

With respect to RCS and MSS overpressurization, the staff agrees that the LONF flow would be bounded by the LOL/TT transient. Both of these transients represent a reduction in the heat removal capability of the secondary system. For the LOL transient, the TT is the initiating event, and so the power mismatch between the primary and secondary side would be greater.

The LONF flow event, without offsite power, is evaluated to test the DNBR SAL, since this event involves a core flow reduction, after the RCPs lose power, as well as the RCS heatup/pressurization due to the power/heat sink mismatch. With respect to DNB, the LONF flow event without offsite power is bounded by the complete loss-of-flow event, in which the effect of the RCP coastdown on DNBR, is not offset, as much, by the effect of RCS pressurization that would be characteristic of an LONF flow. The minimum DNBR, for the complete loss-of-flow event (LR Section 2.8.5.3, frequency decay case) is 1.737 which meets the applicable DNBR SAL of 1.60.

Satisfaction of the third acceptance criterion, that the LONF flow does not develop into a more serious plant condition without the occurrence of another, independent fault, is demonstrated by showing that the AFW system capacity is sufficient to dissipate core residual heat, stored energy, and RCP heat such that reactor coolant water would not be discharged through the

[131] Final Safety Analysis Report for Millstone Power Station, Unit 3

pressurizer relief or safety valves. Reactor coolant water cannot be discharged through the pressurizer relief or safety valves if the pressurizer does not become water-solid. The maximum pressurizer water volume occurs at about the time the decay heat generation rate decreases to the level that can be removed by the AFW system (about 38-50 minutes). The LR (Table 2.8.5.2.3-2) indicates that the maximum pressurizer water volume, predicted for any of the LONF flow cases, is 1731 ft^3, which is less than the total pressurizer volume (1800 ft^3). Therefore, the licensee concludes, and the NRC staff agrees, that the LONF flow would not develop into a more serious plant condition without the occurrence of another, independent fault.

The staff reviewed the licensee's analysis for the LONF flow transient and concluded the analysis was performed using acceptable analytical models. The staff concluded the licensee's analysis at the uprated conditions bound current licensed power operation of the MPS3 unit. Therefore, the staff found the proposed uprate acceptable with respect to the LONF event.

Conclusion

The NRC staff has reviewed the licensee's discussion of the LONF flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of the LONF flow. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the LONF flow event.

2.8.5.2.4 Feedwater System Pipe Breaks Inside and Outside Containment

Regulatory Evaluation

Depending upon the size and location of the break and the plant operating conditions at the time of the break, the break could cause either an RCS cooldown (by excessive energy discharge through the break) or an RCS heatup (by reducing feedwater flow to the affected RCS). In either case, reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered: (1) postulated initial core and reactor conditions; (2) the methods of thermal and hydraulic analyses; (3) the sequence of events; (4) the assumed response of the reactor coolant and auxiliary systems; (5) the functional and operational characteristics of the RPS; (6) operator actions; and (7) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (2) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RVIs so as to significantly impair the capability to cool the core; (3) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized; and

(4) GDC 35, insofar as it requires the reactor cooling system and associated auxiliaries be designed to provide abundant emergency core cooling. Specific review criteria are contained in SRP Section 15.2.8 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Depending on break flow quality, the FLB can result in either an RCS cooldown or heatup. Since the steamline break analysis addresses the RCS cooldown, the FLB is evaluated as an event that can cause an RCS heatup. Analysis of this event demonstrates the ability of the AFW system to remove core decay heat and thereby ensure that the core remains in a coolable geometry. It is inferred that the core remains covered with water (and coolable) by showing that the hot and cold leg temperatures remain subcooled until the AFW system heat removal rate exceeds the core heat generation rate (mainly from decay heat). The NRC staff's review focused on the NSSS response to the FLB event to provide reasonable assurance that the AFW system, in combination with the RPS and safety systems, has adequate capacity to remove decay heat, to prevent overpressurization of the RCS, and to prevent uncovery of the core.

The licensee used the RETRAN[132] computer code to analyze the FLB event. The analyses model a simultaneous loss of main feedwater to all SGs and subsequent reverse blowdown of the faulted SG. The RETRAN FLB methodology was previously reviewed and approved by the NRC staff. A number of cases of FLB have been analyzed, particularly the double-ended rupture of the largest feedwater line, occurring at full power with and without a LOOP.[133] The full double-ended pipe break of the largest feedwater line would correspond to an effective break size of 0.89 ft^2 for MPS3 (Model F SGs).

In a review of another licensee's application for a power uprate, the NRC staff had questioned whether the Westinghouse methodology[134] would accurately identify the limiting break size. The staff noted that it may be possible that the largest possible break size may not yield the most conservative results. As a result of the staff's concerns, an issue report had been entered into the Westinghouse Corrective Action Process to investigate the effects of varying break size on the NOTRUMP low SG level trip mass, the break flow enthalpy, and on the overall RETRAN simulation.

The FLB event can generate a harsh environment in the vicinity of the SG water level sensing reference legs, resulting in false high readings that can delay or prevent a reactor trip on SG low water level. An error allowance, to account for this effect, has been included in the low water level trip setpoints for the Model F SGs, and in the FLB accident analyses. The low-low SG water level setpoint, used for reactor trip and actuation of the AFW system, is zero percent NRS for the MPS3 Model F SGs. The error allowance is included in the TSs to guarantee the trip signal will be generated at zero percent NRS or greater.

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[132] WCAP-14882-P-A (Proprietary), "RETRAN-02 Modeling and Qualification for Westinghouse Pressurized Water Reactor Non-LOCA Safety Analyses," D.S. Huegel, et al, April 1999

[133] WCAP-9230 (Proprietary) and WCAP-9231 (Non-proprietary), "Report on the Consequences of a Postulated Main Feedline Rupture," January 1978

[134] DCL-03-162, "Response to Request for Additional Information Regarding License Amendment Request 03-02, Response Time Testing Elimination and Revision to Technical Specification 3.3.1, Reactor Trip System Instrumentation"

Unlike the assumptions used for the current licensing basis FLB analyses, the power uprate FLB analyses are based upon the assumption that the pressurizer PORVs are not available. Operation of the PORVs is often assumed as a means to limit the maximum RCS pressure, and thereby limit the maximum RCS saturation temperature, in order to minimize the RCS subcooling margin. However, in plants that use charging pumps to supply ECCS flow to the core, like MPS3, limiting the RCS pressure to the PORV opening setpoint also serves to limit the backpressure to the ECCS, and this results in a greater flow of relatively cold water to the RCS via the charging pumps. The cooling effect of ECCS flow would tend to increase the RCS subcooling margin. For MPS3, therefore, assuming the PORVs are not available would have the effect of raising the RCS heatup (due to less ECCS flow) and raising the RCS saturation temperature, which corresponds to the PSV opening setpoint. The net effect on RCS subcooling is not readily predictable.

A comparison of the licensing basis FLB analysis and the SPU FLB analysis can be used to evaluate this assumption. The licensing basis FLB analyses, in which the pressurizer PORVs are assumed to be available, predict that the minimum RCS subcooling would be 22ºF. The SPU FLB analyses, in which the PORVs are not assumed to be available, RCS pressure and saturation temperature would be higher, and the cooling effect from the ECCS flow would be less. The PSVs were assumed to open at 2425 psia, corresponding to a pressure 3 percent below the nominal set-pressure of 2500 psia.

The power uprate FLB analysis results indicate that the minimum margin to hot leg saturation would be only 2.4ºF. These results indicate that, for MPS3, effectively reducing the cooling flow from the ECCS decreases RCS subcooling margin more than raising the RCS saturation temperature increases RCS subcooling margin. The power uprate FLB analysis predicts a lower; but still acceptable RCS subcooling margin. Therefore, the power uprate FLB analyses are based upon the more conservative assumption, with respect to operation of the PORVs.

Since the PORVs were not assumed to be available, the power uprate FLB analyses also indicate that RCS overpressure protection, provided by the PSVs, is sufficient to limit RCS to levels within 110-percent of design pressure.

These cases demonstrate that the AFW system capacity is adequate to remove stored and decay heat, such that the core will remain covered. Therefore, the NRC staff finds that the analyses have demonstrated that the FLB analysis acceptance criteria are satisfied.

Based upon the input parameters, assumptions, and modeling techniques described in LR Section 2.8.5.2.4, and in responses to RAIs, the NRC staff finds the MPS3 FLB transient simulations and the identification of the limiting cases acceptable. The licensee provided reasonable assurance that all of the acceptance criteria continue to be met. The MPS3 AFW system capacity is adequate to remove decay heat, to prevent overpressurizing the RCS, and to prevent uncovering the reactor core. Based upon satisfying these acceptance criteria, the NRC staff finds that the results of the MPS3 FLB analysis acceptable.

The NRC staff concludes that the licensee's analyses adequately account for operation of the licensee's plant at power uprate conditions and were performed using acceptable analytical models. The NRC staff further concludes that the licensee demonstrated that the RPS and safety systems will continue to assure that the ability to insert control rods is maintained, the

RCPB pressure limits will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of propagating fracture of the RCPB is minimized, and abundant core cooling will be provided. The NRC staff concludes that the plant will continue to meet the regulatory requirements at power uprate conditions with respect to the FLB events.

Conclusion

The NRC staff has reviewed the licensee's analyses of feedwater system pipe breaks and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of propagating fracture of the RCPB is minimized, and abundant core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 27, 28, 31, and 35 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to feedwater system pipe breaks.

2.8.5.3 Decrease in Reactor Coolant System Flow

2.8.5.3.1 Loss of Forced Reactor Coolant Flow

Regulatory Evaluation

A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer. An increase in fuel temperature and accompanying fuel damage could then result if SAFDLs are exceeded during the transient. Reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered: (1) the postulated initial core and reactor conditions; (2) the methods of thermal and hydraulic analyses; (3) the sequence of events; (4) assumed reactions of reactor systems components; (5) the functional and operational characteristics of the RPS; (6) operator actions; and (7) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with margin sufficient to ensure that the design condition of the RCPB are not exceeded during any condition of normal operation; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.3.1-2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Partial Loss-of-Coolant Flow

A partial loss-of-coolant flow may be caused by a mechanical or electrical failure in an RCP motor, a fault in the power supply to the pump motor, or a pump motor trip caused by such anomalies as over-current or phase imbalance. The transient is characterized by a rapid

increase in reactor coolant temperature. A partial loss-of-coolant flow may be terminated by either low flow sensed in 2/3 flow sensors on the RCL, or by detection of the reactor coolant pump underspeed.

The licensee analyzed this event at full power and at 60% power. The 60% power analysis, which was analyzed without a loss-of-flow trip, is considered by the licensee a verification of the P-8 setpoint, which the licensee proposes to change from 39% to 50% rated thermal power. The licensee stated that the 60% no-trip analysis demonstrated acceptable compliance with DNBR limits, and the staff accepts the licensee's approach with regard to its demonstration of the acceptability of the P-8 setpoint change.

The licensee used the RETRAN computer code to calculate the loop and core flow during the transient, the time of reactor trip based on RCP speed, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE computer code was then used to calculate the heat flux and DNBR transients based on the nuclear power and RCS flow from RETRAN. The event was analyzed using the RTDP[135] assuming initial reactor power, RCS pressure, and vessel temperature were at their nominal values for uprate conditions. Assumptions are made such that the core power was maximized during the initial part of the transient when the minimum DNBR was reached.

Acceptance criteria for this event include maintaining the DNBR above the SAL, and maintaining both primary and secondary pressures below 110% of the design pressure for each system. Linear heat generation is also demonstrated not to exceed the value at which fuel melt is predicted to occur.

The NRC staff reviewed the licensee's analysis results and concluded that the licensee's analysis was performed using acceptable analytical models and the analysis was bounding for operation under uprate conditions. The staff observed that the results of this transient sequence maintain significant margin to the applicable limits, and are less limiting than the results of the complete loss-of-coolant flow events. The staff concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed uprate. Therefore, the staff found the proposed uprate acceptable with respect to the partial loss of forced reactor coolant flow event.

Complete Loss-of-Coolant Flow

A complete loss of forced reactor coolant flow, an American Nuclear Society (ANS) Condition III event, may result from a simultaneous loss of electrical power supply or a reduction in power supply frequency to all RCPs. A decrease in reactor coolant flow occurring while the plant is at power could result in a degradation of core heat transfer and a subsequent increase in fuel temperature. Accompanying fuel damage could then result if SAFDLs are exceeded during the transient. The RPS is engaged to mitigate the transient. The licensee conservatively applied ANS Condition II acceptance criteria to the analysis of this event. Thus, the licensee demonstrated that the CHF was not exceeded, and pressure in the RCS and MSS remained below 110 percent of their respective design pressures. Specific review criteria are found in SRP Section 15.3.1-15.3.2.

[135] WCAP-11397-P-A, "Revised Thermal Design Procedure," Westinghouse Electric Corporation, April, 1989

The licensee analyzed this accident using the along with the RETRAN computer code to calculate the loop and core flows during the transient, the time of reactor trip based on the calculated RCP speeds, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE was then used to calculate the heat flux and DNBR transients based on the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN.

For the complete loss-of-flow event, the licensee analyzed two transient cases: (1) a loss of power to all pumps; and (2) a frequency decay condition. The licensee indicated that the more limiting event was the frequency decay condition because it resulted in both a higher peak RCS pressure and a lower DNBR. The VIPRE analysis for the frequency decay scenario confirmed that the minimum DNBR value of 1.74 for the frequency decay case was higher than the SAL value of 1.60. The peak RCS and MSS pressures, 2410 psia for RCS and 963 psia for MSS, remained below their respective limits at all times.

The NRC staff reviewed the licensee's analyses of the complete loss of reactor coolant flow and concluded the licensee's analyses were performed using acceptable analytical models. The staff found that the licensee demonstrated that the RPS and safety systems will continue to ensure the minimum DNBR will remain above the SAL and pressure in the RCS and MSS will be maintained below 110 percent of the design pressures. Therefore, the staff finds the proposed uprate acceptable with respect to the complete loss of reactor coolant flow.

Conclusion

The NRC staff has reviewed the licensee's analyses of the decrease in reactor coolant flow event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the decrease in reactor coolant flow event.

2.8.5.3.2 Reactor Coolant Pump Rotor Seizure and Reactor Coolant Pump Shaft Break

Regulatory Evaluation

The events postulated are an instantaneous seizure of the rotor or break of the shaft of a reactor coolant pump. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core coolant flow while the reactor is at power results in a degradation of core heat transfer, which could result in fuel damage. The initial rate of reduction of coolant flow is greater for the rotor seizure event. However, the shaft break event permits a greater reverse flow through the affected loop later during the transient and, therefore, results in a lower core flow rate at that time. In either case, reactor protection and safety systems are actuated to mitigate the transient. The NRC staff's review covered: (1) the postulated initial and long-term core and reactor conditions; (2) the methods of thermal and hydraulic analyses; (3) the sequence of events; (4) the assumed reactions of reactor system components; (5) the functional and operational characteristics of the RPS; (6) operator actions;

and (7) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; (2) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RVIs so as to significantly impair the capability to cool the core; and (3) GDC 31, insofar as it requires that the RCPB be designed with sufficient margin to assure that, under specified conditions, it will behave in a nonbrittle manner and the probability of a rapidly propagating fracture is minimized. Specific review criteria are contained in SRP Section 15.3.3-4 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The postulated locked rotor accident, an ANS Condition IV event, can result from an instantaneous seizure of the RCP rotor or the break of the RCP shaft.

The ANS Condition IV event acceptance criteria were applied as follows:

(1) RCS pressure should be below the designated limit;

(2) Coolable core geometry is ensured by showing that the peak cladding temperature (PCT) and maximum oxidation level for the hot spot are below 2700 °F and 16 percent by weight, respectively; and

(3) Activity release is such that the calculated doses meet 10 CFR 100 guidelines. At MPS3, this corresponds to a limiting amount of 7% of fuel rods experiencing failure.

Specific review criteria are found in SRP Section 15.3.3-4.

The licensee employed two primary computer codes to analyze this event. RETRAN was used to calculate the loop and core flows during the transient, the time of reactor trip based on the calculated flows, the nuclear power transient, and the primary system pressure and temperature transients. The VIPRE was then used to calculate the PCT using the nuclear power and RCS temperature (enthalpy), pressure, and flow from RETRAN.

The licensee analyzed a postulated locked rotor, and noted that the consequences of the locked rotor accident are very similar to those of an RCP shaft break. The locked rotor causes a more rapid, initial reduction in the coolant flow, which results in a more challenging scenario with respect to DNB margin, peak pressure, and peak clad temperature. The RCP shaft break, however, would possibly leave the impeller free to spin in the reverse direction, which would ultimately reduce core flow when compared to the locked rotor scenario. The licensee stated that the postulated locked rotor accident represents the most limiting combination of conditions for this class of accidents. The NRC staff agrees with this approach, because the acceptance criteria for these postulated accidents are challenged early in the sequence of events, when the initial reduction in core flow caused by the locked rotor poses a more limiting scenario.

This postulated accident was analyzed twice. To evaluate peak RCS pressure and PCT, the licensee employed conservative assumptions designed to maximize RCS pressure and cladding temperature transients using the Standard Thermal Design Procedure (STDP). Unlike the RTDP, which analyzes events at nominal conditions and applies uncertainties in a statistical process, the STDP applies uncertainties to initial conditions, which result in a conservative analytical approach. The RTDP approach was used to evaluate the percentage of rods in DNB for confirmation that it was less than 7%, consistent with the radiological analysis.

The peak pressure and temperature analysis assumed initial core power, reactor coolant temperature, and pressure were at maximum values for full-power operation, with allowances for calibration and instrument errors, whereas the DNB analysis used initial conditions consistent with the RTDP approach.

The licensee conservatively assumed that a consequential LOOP occurs due to a grid disturbance resulting from the postulated accident. As a result, a coastdown of the remaining RCPs occurs, although the licensee noted that because reactor power is rapidly reduced as a result of the trip, the remaining RCP coastdowns have little effect on the accident sequence. Actuation of the RPS is the only mitigating feature of the reactor assumed in this accident sequence; the licensee stated that the ESFs are not required to actuate.

For the peak pressure and temperature analysis, the licensee assumed that the initial pressure was 2300 psi to allow for initial condition uncertainties in the pressurizer pressure measurement and control channels. Results were presented at the point of RCS maximum pressure, which was the lower plenum of the reactor pressure vessel. Pressurizer PORVs and sprays, steam dumps, and feedwater flow control were assumed to be unavailable for this accident. The licensee included a +3% setpoint tolerance for the PSVs.

The results of the analysis indicated a peak hot spot cladding temperature of 1718ºF, peak zirconium-water reaction of 0.22%, and a peak RCS pressure of 2617 psia. The total number of rods in DNB is predicted to be less than 7%, which is the analytic limit for the radiological analysis. The licensee noted that these results are more benign than the pre-uprate analysis because the previous analyses were performed using the fuel performance code PAD3.0[136] which has been supplanted by PAD4.0.[137] The staff finds this acceptable because both codes have been NRC-approved. Particularly, PAD 4.0 was approved to replace PAD 3.0 on a “fit-forward” basis.

The NRC staff reviewed the licensee’s analyses of the locked rotor and pump shaft break events and concluded the licensee’s analyses were performed using acceptable analytical models. The staff concluded the plant will continue to meet the regulatory requirements following implementation of the proposed uprate. Therefore, the staff found the proposed uprate acceptable with respect to the postulated RCP locked rotor and shaft break accidents.

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[136] WCAP-10851-P-A, “Improved Fuel Performance Model for Westinghouse Fuel Rod Design and Safety Evaluations,” 1998

[137] WCAP-15063-P-A, “Westinghouse Improved Performance Analysis and Design Model (PAD4.0),” Westinghouse Electric Corporation, July, 2000

Conclusion

The NRC staff has reviewed the licensee's analyses of the sudden decrease in core coolant flow events and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the ability to insert control rods is maintained, the RCPB pressure limits will not be exceeded, the RCPB will behave in a nonbrittle manner, the probability of propagating fracture of the RCPB is minimized, and adequate core cooling will be provided. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 27, 28, and 31 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the sudden decrease in core coolant flow events.

2.8.5.4 Reactivity and Power Distribution Anomalies

2.8.5.4.1 Uncontrolled Control Rod Assembly Withdrawal from a Subcritical or Low Power Startup Condition

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal from subcritical or low power startup conditions may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered: (1) the description of the causes of the transient and the transient itself; (2) the initial conditions; (3) the values of reactor parameters used in the analysis; (4) the analytical methods and computer codes used; and (5) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 20, insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.1 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The Uncontrolled RCCA Withdrawal from Subcritical or Low Power Startup Condition is an ANS Condition II event that is characterized by the insertion of positive reactivity to the reactor core due to the inadvertent withdrawal of an RCCA bank while the plant is in a subcritical or low power startup condition. As such, it is not sensitive to rated thermal power level or secondary-side conditions. The licensee re-analyzed the event to demonstrate acceptable performance at uprated power levels regardless. The analysis recaptures excess margin in the analysis due to conservative assumptions regarding differential rod worths, as discussed below.[138]

[138] Serial No.: 07-0834G, "Dominion Nuclear Connecticut, Inc., Millstone Power Station Unit 3 Response To Request For Additional Information Regarding Stretch Power Uprate License Amendment Request Response To Questions SRXB-07-0013 Through SRXB-07-0047," Millstone Generation, January 11, 2008 (ADAMS Accession No. ML080580476)

The RCCA withdrawal at subcritical or low-power conditions progresses with a very fast flux increase caused by the RCCA withdrawal. Reactivity feedback due to Doppler effects counteracts the flux increase. The transient is terminated by a reactor trip. If unmitigated by a reactor trip, the licensee indicated that the sequence would progress by an initial power increase followed by a power decrease from Doppler effects, followed by a slower increase in nuclear power. As analyzed, the sequence progresses until terminated by any of source or intermediate range high neutron flux trips, or power range high flux, low or high settings. It is also possible that this sequence of events would be terminated by the power range neutron flux high positive rate reactor trip. The licensee's analysis credits the power range neutron flux trip, low setting to terminate this sequence.

The transient is analyzed in a critical condition at 557 ºF. When compared to shutdown conditions, the thermal hydraulic conditions at 557 ºF tend to reduce Doppler effects that compensate for the reactivity addition, and increase peak heat fluxes.

The RCCA withdrawal at low-power conditions is analyzed using the STDP, as the conditions for the transient fall outside the range of applicability of the RTDP. Conservative assumptions that are consistent with the low-power conditions were used to develop the initial conditions for this transient. These assumptions included, but were not limited to, a positive moderator temperature coefficient (MTC), and a Doppler-only power defect of 0.9% delta-k/k, which maximize the nuclear power transient. Assumed uncertainties on the power range hi flux-low setting increase it from the nominal value of 25% to 35%. Two of four reactor coolant pumps are assumed to be in operation; these flow conditions yield conservative DNB estimates.

Concurrent with the re-analysis of this transient for uprated power levels, the licensee adjusted assumptions to differential rod worth evaluated in this transient. Previous analyses assumed a differential rod worth of 145 pcm/in, and the licensee stated that cycle-specific analysis shows excess margin to this limit. The licensee therefore changed the differential rod worth assumption to 100 pcm/in, which corresponds to a reactivity insertion rate of 75 pcm/sec. The licensee stated that cycle-specific core design analyses will assure that the new differential rod worth limits will be met for the uprated core design, and the NRC staff finds that this confirmation will provide reasonable assurance that reduced reactivity insertion rates will remain acceptable. The effect of this assumption is a slower progression of the transient, and additional margin to the DNBR limit is realized as a result.

The licensee analyzed this event using the spatial neutron kinetics code TWINKLE to calculate the core average nuclear power transient, including the various core feedback effects.[139] The FACTRAN code[140] uses the average nuclear power calculated by TWINKLE and performs a fuel rod transient heat transfer calculation to determine the core average heat flux and hot spot fuel temperature transients. The core average heat flux calculated by FACTRAN is finally used in the VIPRE code[141] for DNBR calculations.

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[139] WCAP-7979-P-A, "TWINKLE, A Multi-Dimensional Neutron Kinetics Computer Code," January, 1975
[140] WCAP-7908-A, "FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," Westinghouse Electric Corporation, December, 1989
[141] Sung, Y. X., et al., "VIPRE-01 Modeling and Qualification for Pressurized Water Reactor Non-LOCA Thermal-Hydraulic Safety Analysis," WCAP-14565-P-A (Proprietary), October 1999

The licensee stated that the peak fuel centerline temperature for this transient is 2631 ºF, which is significantly below the minimum temperature expected for fuel melt, 4800 ºF. The minimum DNBR values are presented in Table 2.8.5.4.1-2 of the LR, and are confirmed by the NRC staff to remain above their limits.

The NRC staff reviewed the licensee's analysis of the Uncontrolled RCCA Withdrawal from a subcritical condition and concluded that the licensee's analysis was performed using acceptable analytical models with conservative assumptions regarding initial conditions, nuclear parameters, and mitigating RPS trip signals. The NRC staff also concluded that the plant will continue to meet the regulatory requirements following implementation of the proposed uprate. Therefore, the NRC staff finds the proposed uprate acceptable with respect to the Uncontrolled RCCA Withdrawal from a Subcritical condition event.

Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition and concludes that the licensee's analyses have adequately accounted for the changes in core design necessary for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition.

2.8.5.4.2 Uncontrolled Control Rod Assembly Withdrawal at Power

Regulatory Evaluation

An uncontrolled control rod assembly withdrawal at power may be caused by a malfunction of the reactor control or rod control systems. This withdrawal will uncontrollably add positive reactivity to the reactor core, resulting in a power excursion. The NRC staff's review covered: (1) the description of the causes of the AOO and the description of the event itself; (2) the initial conditions; (3) the values of reactor parameters used in the analysis; (4) the analytical methods and computer codes used; and (5) the results of the associated analyses. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 20, insofar as it requires that the RPS be designed to initiate automatically the operation of appropriate systems, including the reactivity control systems, to ensure that SAFDLs are not exceeded as a result of AOOs; and (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Unlike the Uncontrolled RCCA Withdrawal from Subcritical or Low Power Startup Condition, the Uncontrolled RWAP, also an ANS Condition II event, is affected by rated thermal power, and the secondary system design, since the secondary system is relied upon to remove heat from the primary system while the plant is at power. If the RCCA bank withdrawal event is not terminated by manual or automatic action, the power mismatch and resultant temperature rise could cause DNB and/or fuel centerline melt, and RCS pressure could increase to a level that could challenge the integrity of the RCS PB or the MSS PB. The acceptance criteria are based on not exceeding CHF and maintaining pressures in the RCS and MSS below 110 percent of the design pressures. Specific review criteria are found in SRP section 15.4.2.

The licensee used the RTDP to analyze this transient using a range of reactivity insertion rates, at 10, 60 and 100-percent NSSS power, and minimum and maximum reactivity feedback conditions. A high neutron flux reactor trip was assumed to be actuated at 116.5 percent of nominal full power, which the licensee stated maintains adequate margin to the NTS to account for the required uncertainties. OPΔT and OTΔT trip setpoints were revised to reflect the power uprated power level. The RCCA trip insertion characteristic assumed that the highest worth rod was stuck in its fully withdrawn position. After examination of a range of reactivity insertion rates, a maximum positive reactivity insertion rate was selected that corresponded to the simultaneous withdrawal of the two control rod banks having the maximum combined worth at a speed of 45 inches/minute. Pressurizer sprays and relief valves were assumed to be operational to limit reactor coolant pressure increase. This assumption is listed as conservative because a low pressure will result a more limiting DNB ratio

The licensee used RETRAN to analyze the Uncontrolled RCCA Withdrawal at Power event. RETRAN simulated the neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, SGs, and MSSV. The program calculated pertinent plant variables including temperatures, pressures, power level, and DNBR. A more detailed DNBR analysis for the limiting cases was performed using VIPRE, as well.

The range of cases selected was consistent with the Standard Review Plan 15.4.2. For the slower reactivity insertion rates, the OTΔT trip signal was generated before the power-range high neutron flux trip signal. For the faster reactivity insertion rates, the power-range high neutron flux trip signal occurred first. At 100% power, both cases resulted in a minimum DNBR that was greater than the limit. Results for 60- and 10-percent power were similar to the 100-percent power case. The licensee noted that the DNBR was limiting for the 10-percent case, and VIPRE analyses indicated that a DNBR margin of 3.2-pecent was required to bound the 10-percent case. Because the appropriate amount of available DNBR margin has been allocated for this transient, the staff finds these results acceptable.

The limiting value of DNBR was 1.55, and the SAL is 1.6, resulting in a 3.2-percent DNBR margin allocation for the RWAP transient. This value was obtained for the 10-percent power, minimum feedback case with 12 pcm/sec reactivity insertion rate. The peak core heat flux was obtained from the 100-percent power, maximum feedback case with 34 pcm/sec reactivity insertion rate. A peak secondary pressure was obtained from the 10-percent power, minimum feedback case with a 15 pcm/sec reactivity insertion rate. The NRC staff confirmed that the peak pressure, 1294.6 psia, was within the SAL of 1318.5 psia.

Regarding the potential for a low-power (i.e., below 10-percent power) rod withdrawal error at power, the SPU LR states:

> …a conservative generic evaluation which is applicable to MPS3 has shown that the positive flux rate and high pressurizer pressure functions provide a timely reactor trip that precludes RCS overpressurization in instances where the power range high neutron flux – high setting or the OTΔT trips occur too late to provide the necessary protection. This evaluation confirms that the design RCS pressure limit is met. The generic method has been reviewed and approved by the NRC in Amendments 167 and 168 for the Diablo Canyon Nuclear Plant, Units 1 and 2, dated April 22, 2004. This evaluation method was also used in the current UFSAR analysis.

Because the MPS3 licensee discusses a generic evaluation but references information specific to the Diablo Canyon docket, the NRC staff questioned the generic nature of this evaluation. In the case of this specific analysis, the word, "generic" refers to the bounding nature of the analysis, that is, it applies to 4-loop Westinghouse plants, and not the approval status of the analysis. Indeed, the NRC staff accepted this analysis for referencing at Diablo Canyon in a plant-specific matter, and confirmed that the parameters used in the analysis were acceptable for Diablo Canyon-specific design and operations. The NRC staff has not, however, performed a detailed review of this analysis and concluded that it may be applied to any 4-loop Westinghouse PWR.

In consideration of the information discussed above, the NRC staff requested that the licensee provide additional information about the analysis to support the conclusion that it is applicable to MPS3. In response, the licensee concluded that the generic analysis was performed assuming that the plant has water-filled loop seals on the PSV discharge piping. In comparison to the MPS3-specific plant design, this assumption is conservative, because it results in an analyzed delay in safety valve opening, which causes an increase in the primary system pressure. At MPS3, the safety valves would open sooner, and result in a lower peak pressure. Therefore, the licensee concluded, reference to the generic analysis was not required for MPS3, and the results of the full-power analysis presented in the SPULR adequately demonstrated that the plant would not overpressurize during an RWAP transient.

The NRC staff considered the information provided by the licensee, and agreed that the 1.5 second PSV opening delay, which was assumed in the generic analysis, would make the results of the generic analysis more conservative in consideration of actual conditions at MPS3. However, the NRC staff remained concerned that the analysis presented for RWAP did not adequately demonstrate that the plant would not overpressurize during a postulated, low-power RWAP transient. The NRC staff then requested that the licensee demonstrate, based on sensitivity studies performed on the generic, low-power analysis, that MPS3 did not risk overpressurization during the postulated, low-power RWAP transient.

In response, the licensee performed several sensitivity studies, modulating the assumed core power level, the pressurizer liquid water level, and the PSV opening delay time. The NRC staff evaluated these sensitivity studies during an off-site audit supported by the licensee's contractor, Westinghouse Power Corporation. Although the findings of the audit remain proprietary, the NRC staff documented its findings in a memorandum from B. Parks (Reactor Systems Engineer in the Reactor Systems Branch in the Division of Safety Systems of the

Office of Nuclear Reactor Regulation in the NRC) to G. Cranston (Branch Chief of the Reactor Systems Branch in the Division of Safety Systems of the Office of Nuclear Reactor Regulation in the NRC), dated May 13, 2008.[142] The licensee provided a non-proprietary summary of the Westinghouse information that was made available during the audit.[143]

The adjustments to core power level and pressurizer liquid water level removed assumptions in the generic analysis that were potentially non-conservative. These two modifications alone demonstrated that there remained a small amount of analytic margin to support the conclusion that MPS3 would not overpressurize during the low-power RWAP transient. When the licensee eliminated the 1.5-second PSV opening delay, which is acceptably over-conservative in consideration of the MPS3 plant design, what analytic margin was eliminated by the other two initial condition modifications was recaptured by the more realistic assumptions regarding the PSV opening time. In its review of these sensitivity studies, the NRC staff considered not only these assumptions, but also remaining assumptions employed in the generic analysis. The remaining assumptions contain sufficient conservatism relative to the MPS3 plant design that the NRC staff is reasonably assured that the licensee has demonstrated that, at uprated conditions, the low-power RWAP transient does not threaten to overpressurize the primary system. The transient is terminated by the positive flux rate trip, and adequately mitigated by the relief capacity of the PSVs.

The NRC staff reviewed the licensee's analyses of the Uncontrolled RCCA Withdrawal at Power event and concluded that the licensee's analyses were performed using acceptable analytical models. The staff also concluded that the plant will continue to meet the applicable regulatory requirements following implementation of the proposed uprate. Therefore, the staff found the proposed uprate acceptable with respect to the Uncontrolled RCCA Withdrawal at Power event.

Conclusion

The NRC staff has reviewed the licensee's analyses of the uncontrolled control rod assembly withdrawal at power event and concludes that the licensee's analyses have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. The NRC staff also concludes that the licensee's analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs are not exceeded. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the uncontrolled control rod assembly withdrawal at power.

[142] ADAMS Accession No. ML081350167

[143] DNC letter (07-0450I) to the NRC, "Dominion Nuclear Connecticut, Inc., Millstone Power Station Unit 3 Stretch Power Uprate License Amendment Request Additional Information in Connection with the NRC Audit Held on May 13, 2008 in Rockville, Maryland," dated May 21, 2008 (ADAMS Accession No. ML081420824)

2.8.5.4.3 Control Rod Misoperation

Regulatory Evaluation

The NRC staff's review covered the types of control rod misoperations that are assumed to occur, including those caused by a system malfunction or operator error. The review covered: (1) descriptions of rod position, flux, pressure, and temperature indication systems, and those actions initiated by these systems (e.g., turbine runback, rod withdrawal prohibit, rod block) which can mitigate the effects or prevent the occurrence of various misoperations; (2) the sequence of events; (3) the analytical model used for analyses; (4) important inputs to the calculations; and (5) the results of the analyses. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the reactor core be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC 20, insofar as it requires that the protection system be designed to initiate the reactivity control systems automatically to assure that acceptable fuel design limits are not exceeded as a result of AOOs and to initiate automatically operation of systems and components important to safety under accident conditions; and (3) GDC 25, insofar as it requires that the protection system be designed to assure that SAFDLs are not exceeded for any single malfunction of the reactivity control systems. Specific review criteria are contained in SRP Section 15.4.3 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The RCCA misoperation events are ANS Condition II events that include these incidents:

- One or more dropped RCCAs from the same group;
- A dropped RCCA bank;
- Statically misaligned RCCA; and
- Withdrawal of a single RCCA.

These are transients that are driven by core reactivity and nuclear flux responses to changes in rod positions and are not sensitive to secondary-side conditions. Licensing topical report WCAP-11394-P-A, "Methodology for the Analysis of the Dropped Rod Event," provides a generic procedure for use in analyzing this class of events.[144] The generic dropped RCCA statepoints are evaluated in each cycle as part of the reload safety evaluation process in order to demonstrate that the applicable DNB design basis is satisfied. Use of this NRC-accepted, dropped rod methodology has shown that the DNBR SAL is not exceeded and the acceptance criteria continue to be met.

The staff agreed with the approach for the RCCA misoperation events in the context of the MPS3 uprate. Therefore, the staff agreed the licensing basis acceptance criteria continue to be met and found the RCCA misalignment evaluation acceptable.

[144] WCAP-11394, "Methodology for the Analysis of the Dropped Rod Event," Westinghouse Electric Corporation, April, 1987

Conclusion

The NRC staff has reviewed the licensee's discussion of control rod misoperation events and concludes that the licensee's evaluations have adequately accounted for the changes in core design required for operation of the plant at the proposed power level. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure the SAFDLs will not be exceeded during normal or anticipate operational transients. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 20, and 25 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to control rod misoperation events.

2.8.5.4.4 Startup of an Inactive Loop at an Incorrect Temperature

Regulatory Evaluation

A startup of an inactive loop transient may result in either an increased core flow or the introduction of cooler or deborated water into the core. This event causes an increase in core reactivity due to decreased moderator temperature or moderator boron concentration. The NRC staff's review covered: (1) the sequence of events; (2) the analytical model; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including the effects of AOOs; (2) GDC 20, insofar as it requires that the protection system be designed to automatically initiate the operation of appropriate systems to ensure that SAFDLs are not exceeded as a result of operational occurrences; (3) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design condition of the RCPB are not exceeded during AOOs; (4) GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RVIs so as to significantly impair the capability to cool the core; and (5) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.4.4-5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

MPS3 is equipped with RCL isolation valves. The TSs prohibit power operation with any of the RCL isolation valves closed. The TSs also prohibit power operation with less than all four RCPs in operation. This event is not analyzed, since the plant is not permitted to operate in a configuration at which the event is postulated to occur. The staff finds that this event need not be analyzed to implement the proposed power uprate.

Conclusion

The NRC staff has reviewed the licensee's discussion of the inactive loop startup event and concludes that the licensee's evaluations have adequately accounted for operation of the plant at the proposed power level. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, 20, 26, and 28 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the increase in core flow event.

2.8.5.4.5 Chemical and Volume Control System Malfunction that Result in a Decrease in Boron Concentration in the Reactor Coolant

Regulatory Evaluation

Unborated water can be added to the RCS, via the CVCS. This may happen inadvertently because of operator error or CVCS malfunction, and cause an unwanted increase in reactivity and a decrease in SDM. The operator should stop this unplanned dilution before the SDM is eliminated. The NRC staff's review covered: (1) conditions at the time of the unplanned dilution; (2) causes; (3) initiating events; (4) the sequence of events; (5) the analytical model used for analyses; (6) the values of parameters used in the analytical model; and (7) results of the analyses. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the reactor core and associated coolant, control, and protection systems be designed with appropriate margin to assure that SAFDLs are not exceeded during any condition of normal operation, including AOOs; (2) GDC 15, insofar as it requires that the RCS and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.4.6 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Reactivity can be added to the core by feeding primary water into the RCS via the reactor makeup portion of the CVCS. Boron dilution is a manual operation under strict administrative controls with procedures calling for a limit on the rate and duration of dilution. The CVCS is designed to limit, even under various postulated failure modes, the potential rate of dilution to a value that, after indication through alarms and instrumentation, provides the operator sufficient time to correct the situation in a safe and orderly manner. This event is classified as an ANS Condition II event that requires that the CHF is not exceeded, pressure in the RCS be maintained below the 110 percent design pressure and there is enough time available for operator action that will prevent loss of SDM.

For power and start-up conditions, MODES 1 and 2, the dilution accident erodes the SDM made available through reactor trip. For shutdown MODE initial conditions, Modes 3, 4, 5, and 6, the

dilution accident erodes the SDM inherent in the borated RCS inventory and that which may be provided by control rods (control and shutdown banks) made available through reactor trip.

Analysis of this event involved a calculation of the time required for a constant dilution rate to lose available SDM. The key parameters of interest were the dilution flow, the active RCS volume, the initial boron concentration and the critical boron concentration.

Boron Dilution Parameters

	Initial Boron Concentration (ppm)	Critical Boron Concentration (ppm)	Dilution Flow (gpm)	Dilution Volume (ft3)
Mode 1	2150	1950	150	9934
Mode 2	2150	1950	150	9934
Mode 3	Initial and critical boron concentrations for Modes 3-5 are determined based on the 15 minute response time from operator notification.		150	8760
Mode 4			150	3885
Mode 5			150	3885 (3624 Drained)

The licensee provided the parameters for each MODE except Mode 6. The licensee stated that Technical Specification requirements preclude boron dilution during refueling operations, and the staff agrees that an analysis of boron dilution during Mode 6 is therefore unwarranted.

During its review, the NRC staff observed that dilution volumes and initial boron concentrations presented for the power uprate analyses were different from those presented in the current licensing basis. For instance, the current licensing basis assumes, for operating modes, a 500 ppm dilution to reach critical boron concentration. This difference in assumptions results in less available time to terminate the boron dilution in the uprate analyses, but still remains within the 15 minute SRP acceptance criterion. The licensee stated that the dilution volumes assumed in the analyses for the power uprate also include correction of a Westinghouse-identified generic discrepancy associated with the RCS volume contained in the RCS loop stop valves, and that the power uprate analyses have been performed with conservative assumptions to bound the discrepancy.

The following table presents the results of the licensee's boron dilution analyses for Modes 1 and 2, which shows that the results are acceptable.

Boron Dilution Results

Condition	**Uprate Analysis**	**Limit**
Mode 1 Manual Rod Control	30.3 Minutes	15 Minutes
Mode 1 Auto Rod Control	33.8 Minutes	15 Minutes
Mode 2	35.6 Minutes	15 Minutes

As can be seen from the above table the licensee has sufficient margin for its Mode 1 and 2 dilution events. For Modes 3-5, the available time from operator notification is 15 minutes to terminate the boron dilution. Using this assumption as a basis, the licensee analyzes the boron dilution event to generate minimum SDM requirements as a function of the critical boron concentration. The staff finds this approach acceptable because it preserves the 15 minute operator termination time limit.

The staff reviewed the assumptions that the licensee employed for the analyses, and confirmed that, to the extent that the licensing basis does not change for the uprate, the analytical assumptions remain conservatively bounding of or consistent with the licensing basis. The analyzed reductions in margin between initial and critical boron concentration are reflected in the analysis results, which remain acceptable. Therefore, the staff finds that the licensee's analysis of boron dilution events acceptable for the proposed power uprate.

Conclusion

The NRC staff has reviewed the licensee's analyses of the decrease in boron concentration in the reactor coolant due to a CVCS malfunction and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the decrease in boron concentration in the reactor coolant due to a CVCS malfunction.

2.8.5.4.6 Spectrum of Rod Ejection Accidents

Regulatory Evaluation

Control rod ejection accidents cause a rapid positive reactivity insertion together with an adverse core power distribution, which could lead to localized fuel rod damage. The NRC staff evaluates the consequences of a control rod ejection accident to determine the potential damage caused to the RCPB and to determine whether the fuel damage resulting from such an accident could impair cooling water flow. The NRC staff's review covered initial conditions, rod patterns and worths, scram worth as a function of time, reactivity coefficients, the analytical model used for analyses, core parameters which affect the peak reactor pressure or the probability of fuel rod failure, and the results of the transient analyses. The NRC's acceptance criteria are based on GDC 28, insofar as it requires that the reactivity control systems be designed to assure that the effects of postulated reactivity accidents can neither result in damage to the RCPB greater than limited local yielding, nor disturb the core, its support structures, or other RVIs so as to impair significantly the capability to cool the core. Specific review criteria are contained in SRP Section 15.4.8 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Control rod ejection accidents cause a rapid positive reactivity insertion together with an adverse core power distribution that could lead to localized fuel rod damage. Since the key acceptance criterion is maximum fuel stored energy, initial plant conditions are selected to maximize fuel stored energy. This event is considered at 0% and 100% power, and at BOC and EOC. Since the RCCA ejection transient is a rapid transient, initial plant conditions, such as power level, pressure, flow, and temperature are not significant.

The licensee applied acceptance criteria to its analysis based on experimental testing and on conclusions drawn in WCAP-7588.[145] Analytical limits on stored energy for both previously irradiated and unirradiated fuel are 200 cal/g, and fuel melt must remain less than 10 percent of the pellet volume at the hot spot. Acceptance for pressure surges is based on not exceeding faulted-condition stress limits, and the licensee provided a generic disposition for this criterion. The NRC staff observes that these acceptance criteria are more rigorous than those contained in Regulatory Guide 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors."[146] The calculation of the RCCA ejection accidents is performed using a two-stage process. An average core calculation is performed using the TWINKLE spatial neutron kinetics code,[147] followed by a hot spot analysis using FACTRAN.[148] The control rod ejection accident analyses for MPS3 were performed assuming the uprate power level, at BOC and EOC. The full power cases indicated that 4.66% and 6.86% of the fuel would melt (BOC and EOC). The corresponding maximum fuel stored energy was 175.8 and 173.7 cal/g. For the zero power cases, there was no fuel melt, and the maximum fuel stored energy was 152.4 and 158.3 cal/g (BOC and EOC).

The licensee provided a comparison of RCCA ejection accident analysis results from the current licensing basis to those proposed for the power uprate. The comparison indicated some reductions in fuel stored energy and predicted peak clad temperature, although the staff observed that the results were largely consistent from pre- to post-power uprate. The licensee stated that previous analyses used overly conservative reactivity coefficients, the replacement of which has partially offset the penalties for this accident associated with increased power. The staff finds this approach acceptable, because the analysis assumptions and results are re-confirmed on a cycle-specific basis such that there is reasonable assurance that the reactivity coefficients used in the uprate analysis will remain bounding on a cycle-specific basis, or the analysis will be re-performed.

As a result of a fuel failure during a test at the CABRI reactor in France in 1993, and one in 1994 at the NSRR test reactor in Japan, the NRC recognized that high burnup fuel cladding might fail during a reactivity insertion accident (RIA), such as a Rod Ejection event, at lower enthalpies than the limits currently specified in RG 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors."[149] However, generic analyses performed by all of the reactor vendors have indicated that the fuel enthalpy during RIAs will be much lower than the RG 1.77 limits, based on their 3D neutronics calculations. For high burnup fuel which has been burned so long that it no longer contains significant reactivity, the fuel enthalpies calculated using the 3D models are expected to be much less than 100 cal/g.

The staff has concluded that although the RG 1.77 limits may not be conservative for cladding failure, the analyses performed by the vendors, which have been confirmed by NRC-sponsored calculations, provide reasonable assurance that the effects of postulated RIAs in operating plants with fuel burnups up to 60 gigawatt days per metric ton uranium will neither: (1) result in

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[145] WCAP-7588, "An Evaluation of the Rod Ejection Accident in Westinghouse Pressurized Water Reactors using Special Kinetics Methods," January, 1975

[146] NRC Regulatory Guide 1.77, "Assumptions Used for Evaluating a Control Rod Ejection Accident for Pressurized Water Reactors," May, 1974.

[147] WCAP-7979-P-A, "TWINKLE, A Multi-Dimensional Neutron Kinetics Computer Code," January, 1975

[148] WCAP-7908-A, "FACTRAN – A FORTRAN-IV Code for Thermal Transients in a UO_2 Fuel Rod," Westinghouse Electric Corporation, December, 1989

[149] ADAMS Accession No. ML003710279

damage to the RCPB; nor (2) sufficiently disturb the core, its support structures, or other reactor pressure vessel (RPV) internals to impair significantly the capability to cool the core as specified in current regulatory requirements.

A generic calculation of the pressure surge for an ejected rod worth of one dollar at BOL, HFP, indicated that the peak pressure would not exceed faulted condition stress limits for the reactor pressure vessel. At MPS3 uprated conditions, the severity of the RCCA ejection accidents does not exceed the worst-case analysis such that the generic disposition remains bounding and applicable.

Since fuel and clad limits are not exceeded, there is no danger of sudden fuel dispersal into the coolant, and since the peak pressure does not exceed the faulted condition stress limits, there is no danger of additional damage to the RCS. The analyses demonstrate that the fission product release as a result of fuel rods entering DNB is limited to less than 10% of the fuel rods in the core.

Accordingly, the NRC staff finds that the results and conclusions of the analyses performed for the control rod ejection accident are acceptable for operation at the proposed uprate power level of 3650 MWt for MPS3.

Conclusion

The NRC staff has reviewed the licensee's analyses of the rod ejection accident and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that appropriate reactor protection and safety systems will prevent postulated reactivity accidents that could: (1) result in damage to the RCPB greater than limited local yielding; or (2) cause sufficient damage that would significantly impair the capability to cool the core. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDC 28 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the rod ejection accident.

2.8.5.5 Inadvertent Operation of ECCS and Chemical and Volume Control System Malfunction that Increases Reactor Coolant Inventory

Regulatory Evaluation

Equipment malfunctions, operator errors, and abnormal occurrences could cause unplanned increases in reactor coolant inventory. Depending on the boron concentration and temperature of the injected water and the response of the automatic control systems, a power level increase may result and, without adequate controls, could lead to fuel damage or overpressurization of the RCS. Alternatively, a power level decrease and depressurization may result. Reactor protection and safety systems are actuated to mitigate these events. The NRC staff's review covered: (1) the sequence of events; (2) the analytical model used for analyses; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated

auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during AOOs; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.5.1-2 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

The inadvertent ECCS at power event and the CVCS Malfunction that increases RCS inventory events are analyzed using the RETRAN computer code. The RETRAN computer code is used to simulate transient behavior in light water reactor systems. The code includes a one-dimensional homogeneous equilibrium mixture thermal-hydraulic model, an ECCS model, and a non-equilibrium pressurizer model. The code computes pertinent plant variables including temperatures, pressures and power level.

Inadvertent Operation of ECCS

An inadvertent actuation of the ECCS at power event, an AOO, could be caused by operator error or a false electrical actuating signal. The ECCS uses the charging pumps to pump borated water from the RWST into the cold leg of each RCS loop. The safety injection pumps are also actuated; but they are not capable of delivering flow to the RCS when the RCS is at nominal pressure.

The inadvertent ECCS actuation at-power event will continue to add water to the RCS until the ECCS is shut off by the operator. This event could develop into a more serious event, e.g., a small break LOCA , if the pressurizer fills and a pressurizer relief or safety valve opens and fails to reseat.[150] This would be a violation of the ANS Condition II acceptance criterion that prohibits escalation of a Condition II event to a more serious event.

A simple way to show that this ANS Condition II acceptance criterion is met is to show that there is enough time for the operator to shut off the ECCS charging pump flow before the pressurizer can become water-solid. The possibility that a pressurizer relief or safety valve fails to reseat is thereby eliminated, since an open pressurizer relief or safety valve would not have to discharge any water. MPS3 is equipped with PORVs that are qualified as safety-related components. They have Class 1E control circuitry and are qualified for water relief.[151] Therefore, they may be credited to mitigate an event like the inadvertent actuation of the ECCS at power event or the CVCS malfunction that increases RCS inventory, provided they are available (i.e., their associated block valves are not closed). Therefore, for MPS3, it is not necessary to shut off the ECCS charging pump flow before the pressurizer can become water-solid. It would be sufficient to show that there is enough time for the operator to open at least one PORV block valve before the pressurizer can become water-solid. This would prevent the PSV from opening, relieving water, and possibly sticking open. The PSVs are not isolable. This approach is applied, by MPS3, in the analysis of the CVCS malfunction that increases RCS inventory (below).

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[150] Issuance of Amendment 161 - Millstone Nuclear Power Station, Unit 3 (TAC No. MA1527), June 5, 1998 (ADAMS Accession No. ML011800207).

[151] WCAP-12945-P-A, “Code Qualification Document for Best-Estimate LOCA Analysis,” Westinghouse Electric Corporation, 1998

For the analysis of the inadvertent ECCS at power event, MPS3 applies a new approach. The licensee proposes to add a new permissive (P-19) to low RCS pressure protection system logic. The P-19 permissive would be based upon the existing low pressurizer pressure reactor trip two-out-of-four bistable trip logic, and would be set to the existing low pressurizer pressure reactor trip setpoint. The P-19 permissive would permit the cold leg injection valves to open automatically upon receiving the safety injection signal. The proposed logic, therefore, would require the P-19 permissive, in coincidence with the safety injection signal, to open the cold leg injection valves, and allow delivery of ECCS charging pump flow to the RCS cold legs.

The licensing report contained in the license amendment request, dated July 13, 2007, indicates that no credit is taken for boron addition from the charging pumps for steam line break DNBR analyses. ECCS charging flow is modeled for steam line break mass and energy releases; however, ECCS flow is assumed to be initated on low pressurizer pressure and this is unaffected by the implementation of the P-19 permissive. Charging flow is credited for assisting in maintaining hot leg saturatin for FLB; however, ECCS flow is assumed to be initiated on low pressurizer pressure and thus is unaffected by the implementation of the P-19 permissive.

In major steam line breaks, the safety injection signal is often derived from the low steam line pressure signal. This is soon followed by the low pressurizer pressure SI signal. The P-19 permissive would be generated before the low pressurizer pressure SI signal. Therefore, there may be a slight delay in the ECCS actuation; but that is not significant because the early introduction of ECCS water does not mitigate the event. Rather, it is the emptying of the faulted SG that effectively ends the event. In the spurious opening of a steam line safety valve, the safety injection signal is derived from the low pressurizer pressure SI signal. Here, too, the P-19 permissive would be generated before the low pressurizer pressure SI signal.

In the FLB analysis, the safety injection signal is derived from the low pressurizer pressure SI signal. Here, too, the P-19 permissive would be generated before the low pressurizer pressure SI signal.

With the P-19 permissive in place, a safety injection signal (whether valid or spurious) would not cause the ECCS to supply any charging flow to the RCS cold legs unless pressurizer pressure is below the low pressurizer pressure reactor trip setpoint. Charging flow would continue to be delivered to the RCP seals, for cooling. The P-19 permissive essentially eliminates the ability of the ECCS to automatically deliver flow to the RCS cold legs at pressures above the low pressurizer pressure reactor trip setpoint. RCP seal cooling flow would eventually fill the pressurizer and pressurize the RCS to pressure levels that can lift the pressurizer PORVs or PSVs. However, this would be substantially delayed by the proposed P-19 permissive.

The RCP seal injection flow would not cause the pressurizer to become water-solid condition until one-half hour after the ECCS is actuated. If the PORVs are assumed to be unavailable, then the PSVs would open at more than one-hour. Operators, therefore, have more than one hour to make at least one PORV available for opening, by confirming that the pressurizer PORV block valves are open. One PORV has sufficient capacity to prevent the opening of the PSVs. As stated above, although MPS3's PORVs are qualified for water relief, the PSVs are not. Therefore, for MPS3, water relief through a PSV, not a PORV, could lead to a more serious plant condition.

The NRC staff agrees with the licensee's proposed addition of the P-19 permissive, and with the analytical approach, assumptions, and results. The staff also notes that, with the availability of water-qualified PORVs and the introduction of the proposed P-19 permissive, MPS3 operators would have sufficient time to deal with an inadvertent ECCS at power event.

CVCS Malfunction that Increases RCS Inventory

The CVCS malfunction that increases RCS inventory is an ANS Condition II event that is evaluated for the effects of adding water inventory to the RCS. This event could be caused by operator error or a spurious actuating signal. In this case, the fault is assumed to be a spurious, low pressurizer water level signal, which would cause charging flow increase to its maximum rate. If the charging system were under automatic control, and the pressurizer level channel that is used for charging control were to fail in the low direction, this would result in: (1) the maximum amount of charging flow to be delivered to the RCS; (2) letdown flow would be isolated; and (3) a low level alarm would be issued. If a second pressurizer level transmitter were to fail in an as-is condition or a low condition (as the worst single failure), then reactor trip, on two-out-of-three high pressurizer level channels, would be defeated. Makeup water, of a boron concentration that is equal to the boron concentration in the RCS, is added until the operator acts to terminate the flow. If the charging flow is ended before the pressurizer becomes water-solid, then the possibility of a PORV opening, discharging water, and failing to reseat properly is eliminated.

The proposed P-19 permissive, which has been shown to be useful in the inadvertent ECCS at power event, has no effect upon the CVCS malfunction event. Either event, the inadvertent actuation of the ECCS at power or the CVCS malfunction, can cause the pressurizer to become water-solid, and result in water discharge from the pressurizer; but in the CVCS malfunction, the time to fill the pressurizer is less, since one or two charging pumps would be delivering flow to the RCS cold legs (not just the RCP seals), in an effort to restore the pressurizer water level that is indicated low.

The effect of a reactor trip, if one occurs during the transient, would temporarily reduce pressurizer water level, and provide additional time for corrective action by the operators. The effect of adding water inventory to the RCS, with no change in boron concentration, would be an increase in pressurizer water level. A reactor trip would be expected from the two-out-of-three pressurizer high water level trip logic. If one channel (the CVCS controlling channel) fails low, and another channel is assumed to fail, either low or as-is, as the single protection system failure, then the two-out-of-three voting trip logic would not be fulfilled, and the reactor trip would not be demanded.

The licensee provides two CVCS malfunction cases, with one and two charging pumps in operation, to show that there is sufficient time available for the operators to end the event (by defeating the failed channel and restoring automatic letdown and charging control to one of the two operable channels), or make at least one PORV available before the pressurizer can fill and cause water to be discharged through the PSVs. The licensee's analyses do not credit a reactor trip, since the pressurizer high water level reactor trip could be defeated as part of the postulated scenario.

With one charging pump in operation, the pressurizer is predicted to become water-solid by about 12.7 minutes after initiation of the event. The failure of the (controlling) pressurizer level channel will generate several main control board alarms, including the following:

- Pressurizer Level Deviation
- Pressurizer Level Low Heater Off and Letdown Secure
- Pressurizer heater Backup Group Auto Trip
- Pressurizer heater Control Group Auto Trip

There are several other alarms available, such as the charging pump high flow alarm. Although the alarms are not classified as safety-grade, they originate from safety related instrumentation, and they monitor several different parameters. Their reliability is such that they may be credited to alert the operators of the event, consistent with the current licensing basis. If a PORV does not open, then the PSVs are predicted to open at about 19 minutes, at which point they would be assumed to fail open and create a more serious event.

This event is among the licensee's simulator training exercises for initial operator qualification and requalification. The operators are expected to place the charging pump flow control in manual and terminate the pressurizer overfill before the reactor trips. If reactor trip occurs on high water level, shortly before pressurizer overfill, then this amounts to about a 10-minute limit. Experience from the simulator exercises shows that the operators will routinely meet this expectation.

For the case in which two pumps are assumed to be operating, the pressurizer is predicted to become water-solid condition at about 8.4 minutes, following initiation of the event. If a PORV does not open, then the PSVs are predicted to open at about 10 minutes, at which point they would be assumed to fail open and create a more serious event. Operation with two charging pumps would occur briefly when transferring the charging function from one pump to the other, and this is done with charging manual control. Therefore, this operation is not susceptible to the postulated channel failure. Two-pump operation is also used to reduce radiation doses at the end of the operating cycle, for about two weeks, in preparation for shutdown. During this limited period, the operator would be required to confirm that at least one PORV is available within about 8 minutes following initiation of the event.

The staff reviewed the licensee's evaluation of the CVCS malfunction event and agrees with the licensee's assumptions, methods and conclusions. The staff agrees, too, that the operator has sufficient time to prevent this event from escalating into a more serious event. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed power uprate with respect to the CVCS malfunction transient.

Conclusion

The NRC staff has reviewed the licensee's analyses of the inadvertent operation of ECCS and CVCS event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26

following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the inadvertent operation of ECCS and CVCS event.

2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 Inadvertent Opening of Pressurizer Pressure Relief Valve

Regulatory Evaluation

The inadvertent opening of a pressure relief valve results in a reactor coolant inventory decrease and a decrease in RCS pressure. A reactor trip normally occurs due to low RCS pressure. The NRC staff's review covered: (1) the sequence of events; (2) the analytical model used for analyses; (3) the values of parameters used in the analytical model; and (4) the results of the transient analyses. The NRC's acceptance criteria are based on: (1) GDC 10, insofar as it requires that the RCS be designed with appropriate margin to ensure that SAFDLs are not exceeded during normal operations, including AOOs; (2) GDC 15, insofar as it requires that the RCS and its associated auxiliary systems be designed with sufficient margin to ensure that the design conditions of the RCPB are not exceeded during any condition of normal operation, including AOOs; and (3) GDC 26, insofar as it requires that a reactivity control system be provided, and be capable of reliably controlling the rate of reactivity changes to ensure that under conditions of normal operation, including AOOs, SAFDLs are not exceeded. Specific review criteria are contained in SRP Section 15.6.1 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

An accidental depressurization of the RCS could occur as a result of an inadvertent opening of a pressurizer relief valve. To conservatively bound this scenario, the Westinghouse methodology models the failure of a PSV since a safety valve is sized to relieve approximately twice the steam flow rate of a relief valve and will allow a much more rapid depressurization upon opening. The reactor may be tripped on low pressurizer pressure, or on OTΔT.

Analysis of the accidental depressurization of the RCS is required to meet the ANS Condition II criteria. The key acceptance criterion is demonstration that the DNBR is not reduced below the SAL at any time during the transient. Additionally, RCS and MSS pressures should be maintained within their design limits. As this is a depressurization event; pressure limits are not challenged.

The licensee analyzed this event using the RETRAN computer code to simulate neutron kinetics, RCS, pressurizer, pressurizer relief and safety valves, pressurizer spray, SG, and SG safety valves. The code computes pertinent plant variables including temperatures, pressures, and power level. The licensee performed the analysis in accordance with the RTDP to calculate the minimum DNBR during the transient. Assumptions used for the analysis included conservative reactivity coefficients to reduce negative reactivity effects, or to maximize any power increase, associated with the transient.

The licensee's analysis indicated that the reactor tripped on OTΔT, and resulted in a minimum DNBR of 1.874, in comparison to a previously analyzed value of 1.584 for the currently licensed thermal power level. The licensee indicated that the increase in DNBR for this transient is

based on the analysis of RFA-fuel, and introduction of the WRB-2M correlation. Previous analyses included a large penalty on calculated DNBRs due to rotated intermediate flow mixing grids for Vantage 5-Hybrid fuel.

The NRC staff reviewed the licensee's demonstration analyses of inadvertent pressurizer pressure relief valve opening, performed in accordance with the NRC-approved RETRAN transient analysis methodology using the RTDP. The staff concluded that the licensee demonstrated the RPS and safety systems will continue to provide reasonable assurance that the DNB SAL will not be violated. Since this is a depressurization event, the RCS and secondary pressure limits are not challenged. The staff concludes that the plant will continue to meet the regulatory requirements following implementation of the proposed power uprate. Therefore, the NRC staff found the proposed power uprate acceptable with respect to the accidental depressurization of the RCS event.

Conclusion

The NRC staff has reviewed the licensee's analyses of the inadvertent opening of a pressurizer pressure relief valve event and concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that the SAFDLs and the RCPB pressure limits will not be exceeded as a result of this event. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 10, 15, and 26 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the inadvertent opening of a pressurizer pressure relief valve event.

2.8.5.6.2 Steam Generator Tube Rupture

Regulatory Evaluation

A steam generator tube rupture (SGTR) event causes a direct release of radioactive material contained in the primary coolant to the environment through the ruptured SG tube and main steam safety or atmospheric relief valves. Reactor protection and ESFs are actuated to mitigate the accident and restrict the offsite dose to within the guidelines of 10 CFR Part 100. The NRC staff's review covered: (1) postulated initial core and plant conditions; (2) method of thermal and hydraulic analysis; (3) the sequence of events (assuming offsite power either available or unavailable); (4) assumed reactions of reactor system components; (5) functional and operational characteristics of the RPS; (6) operator actions consistent with the plant's emergency operating procedures (EOPs); and (7) the results of the accident analysis. A single failure of a mitigating system is assumed for this event. The NRC staff's review of the SGTR is focused on the thermal and hydraulic analysis for the SGTR in order to: (1) determine whether 10 CFR Part 100 is satisfied with respect to radiological consequences, which are discussed in Section 2.7 of this safety evaluation; and (2) confirm that the faulted SG does not experience an overfill. Preventing SG overfill is necessary in order to prevent radioactive liquid releases to the environment and to prevent the failure of main steam lines. Specific review criteria are contained in SRP Section 15.6.3 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

A SGTR accident, an ANS Condition IV event, will transfer radioactive reactor coolant to the shell side of the SG as a result of the ruptured tube, and ultimately to the atmosphere. Therefore, the SGTR analyses for the proposed power uprate were performed to show that the resulting offsite radiation doses will stay within the allowable guidelines and there was margin available to assure that no SG overfilling occurred. Specific review criteria for the staff review are found in SRP 15.6.3. This review considers the thermal hydraulic modeling of the accident, and not the radiological consequences.

The SGTR analyses assume the complete severance of one SG tube. Other assumptions are a NSSS power level of 3666 MWt plus 2-percent calorimetric uncertainty and a full-power T_{avg} operating range of 581.5º to 589.5ºF, with a 10-degree end-of-cycle coastdown. The analyses also consider up to 10-percent SG tube plugging, and a main feedwater temperature range from 390ºF to 445.3ºF.

The SGTR analyses from the current licensing basis assume that the AFW is terminated when the ruptured SG level reaches 29 percent narrow-range, or at 16.5 minutes, whichever is greater. The licensee now proposes to assume the isolation of AFW at 30 percent narrow-range. The NRC staff finds that the licensee's proposal is justified because it is based on implementation of symptom-based EOPs and operator training experience.

The licensee analyzed the SGTR using the NRC-approved LOFTTR2 program,[152] which is a modification to the LOFTRAN code[153] designed to facilitate the input of operator actions required to analyze this event. The NRC staff has approved of the LOFTTR2 program for SGTR analysis.

Two separate SGTR analyses were completed; one was performed to demonstrate margin-to-overfill in order to demonstrate that the sequence of events does not result in overfilling the faulted SG. Because the assumptions used in this analysis may not result in the most significant radiological release, a separate analysis was performed using assumptions to maximize the mass release through the ruptured SG tube.

The licensee performed sensitivity studies to determine the most limiting set of analysis conditions. In both analysis cases, the studies considered RCS initial average temperature, SG tube plugging, initial secondary water mass, feedwater temperature, and auxiliary feed flow.

For the margin-to-overfill cases, initial water mass in the SG was assumed to be 90 percent of nominal full power mass. A turbine runback was not assumed because it delays reactor trip, and an earlier trip results in greater atmospheric steam releases from the SGs. The maximum auxiliary feed flow was assumed, since it was determined to provide the lowest margin to overfill.

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[152] WCAP-10698-P-A, "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill," August, 1987, and Supplement 1, "Evaluation of Offsite Radiation Dose for a Steam Generator Turbine Rupture Accident," March, 1986

[153] WCAP-7907-P-A (Proprietary), WCAP-7907-A (Nonproprietary), April 1984, Burnett, T. W. T., et al., "LOFTRAN Code Description"

For the mass release cases, the initial SG water mass was increased to 110 percent of nominal full power mass, because the higher initial water mass increased the post-trip flashed break flow and total integrated break flows. A turbine runback was simulated, but its effect on delaying the reactor trip was not credited. This assumption increased the secondary water mass. Maximum auxiliary feed flow was modeled because it provided the most conservative mass release data.

The SGTR analysis credits certain operator actions. The operator must first identify the ruptured SG, then isolate steam flow from the ruptured SG. The RCS is then cooled and depressurized, and safety injection flow is terminated. The RCS is cooled to RHRS entry conditions, and the ruptured SG is cooled and depressurized. These actions are defined in the Westinghouse Owners' Group Emergency Response E-3 Series of Guidelines. The licensee stated that initiation times were changed, and plant/system response times were changed. The staff reviewed the documents and noted that the operator time to initiate safety injection termination was increased from 3 to 6 minutes, and the licensee stated that the plant/system response times changed as a result of the thermal hydraulic analysis. The staff finds that the increase in safety injection termination time is acceptable because it represents an increase in operator action time, and is accounted for in the analysis. The change of plant response times is also acceptable because the new response times are based on the uprated thermal hydraulic analyses, and are hence reflective of the plant's response at uprated conditions.

The NRC staff has reviewed the licensee's analyses of the SGTR event. The operator actions credited in the analysis are based on operator training experience and are consistent with Westinghouse Owner's Group Emergency Operating Procedures. The accident was modeled using an approved method, LOFTRR2,[154] and the input conditions were demonstrated to be conservative by sensitivity study. The margin-to-overfill analysis predicted that 698 ft^3 of margin-to-overfill remained on the secondary side of the SG, which has a total volume of 5850 ft^3.

On the basis of the items discussed above, the staff concludes that the thermal hydraulic analysis of the SGTR accident is acceptable, and that there is reasonable assurance that the faulted SG will not overfill. The staff finds, therefore, that the proposed uprate is acceptable with respect to the SGTR event.

Conclusion

The NRC staff has reviewed the licensee's analysis of the SGTR accident and concludes that the licensee's analysis has adequately accounted for operation of the plant at the proposed power level and was performed using acceptable analytical methods and approved computer codes. The NRC staff further concludes that the assumptions used in this analysis are conservative and that the event does not result in an overfill of the faulted SG. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the SGTR event.

[154] WCAP-10698-P-A, "SGTR Analysis Methodology to Determine the Margin to Steam Generator Overfill," August, 1987, and Supplement 1, "Evaluation of Offsite Radiation Dose for a Steam Generator Tube Rupture Accident," March, 1986

2.8.5.6.3 Emergency Core Cooling System and Loss-of-Coolant Accidents

Regulatory Evaluation

LOCAs are postulated accidents that would result in the loss of reactor coolant from piping breaks in the RCPB at a rate in excess of the capability of the normal reactor coolant makeup system to replenish it. Loss of significant quantities of reactor coolant would prevent heat removal from the reactor core, unless the water is replenished. The reactor protection and ECCS systems are provided to mitigate these accidents. The NRC staff's review covered: (1) the licensee's determination of break locations and break sizes; (2) postulated initial conditions; (3) the sequence of events; (4) the analytical model used for analyses, and calculations of the reactor power, pressure, flow, and temperature transients; (5) calculations of PCT, total oxidation of the cladding, total hydrogen generation, changes in core geometry, and long-term cooling; (6) functional and operational characteristics of the reactor protection and ECCS systems; and (7) operator actions. The NRC's acceptance criteria are based on: (1) 10 CFR 50.46, insofar as it establishes standards for the calculation of ECCS performance and acceptance criteria for that calculated performance; (2) 10 CFR Part 50, Appendix K, insofar as it establishes required and acceptable features of evaluation models for heat removal by the ECCS after the blowdown phase of a LOCA; (3) GDC 4, insofar as it requires that SSCs important to safety be protected against dynamic effects associated with flow instabilities and loads such as those resulting from water hammer; (4) GDC 27, insofar as it requires that the reactivity control systems be designed to have a combined capability, in conjunction with poison addition by the ECCS, of reliably controlling reactivity changes under postulated accident conditions, with appropriate margin for stuck rods, to assure the capability to cool the core is maintained; and (5) GDC 35, insofar as it requires that a system to provide abundant emergency core cooling be provided to transfer heat from the reactor core following any LOCA at a rate so that fuel clad damage that could interfere with continued effective core cooling will be prevented. Specific review criteria are contained in SRP Sections 6.3 and 15.6.5 and other guidance provided in Matrix 8 of RS-001.

Technical Evaluation

Large Break LOCA

Large break LOCA analyses supporting the proposed power uprate were performed by the licensee using the NRC-approved Automated Statistical Treatment of Uncertainty Method (ASTRUM) best-estimate large break LOCA (BE-LBLOCA) methodology.

Westinghouse obtained generic NRC approval of its original topical report describing the BE-LBLOCA methodology in 1996 for 3- and 4-loop PWRs.[155] Westinghouse recently completed a program to revise the statistical approach used to develop the PCT and oxidation results at the 95th percentile. This newer method is based on the Code Qualification Document (CQD) methodology described in WCAP-10698-P-A, and follows the steps in the Code Scaling

[155] NUDOCS 9604160321, Staff Safety Evaluation for WCAP-12945P, "Westinghouse Code Qualification Document for Best Estimate Loss of coolant Accident Analysis," March 5, 1996

Applicability and Uncertainty (CSAU) methodology[156]. The acceptability of the method, which relies on WCOBRA/TRACC evaluations, was reviewed using the guidance contained in Regulatory Guide 1.157.[157] The staff's evaluation of the original analytical technique is discussed in its safety evaluation of the CQD methodology, and the associated technical evaluation report presents the basis for the staff's acceptable findings.

However, the uncertainty analysis in the CQD methodology is replaced by a technique based on order statistics. The ASTRUM methodology replaces the response surface technique with a statistical sampling method in which the uncertainty parameters are simultaneously sampled for each case.[158] The approved ASTRUM evaluation model is documented in WCAP-16009-P-A, and the staff's safety evaluation documents the acceptability of the ASTRUM methodology. The staff reviewed the technical basis for its acceptable findings and found that the MPS3 application is in accordance with this basis. The staff furthermore compared the MPS3 application of the methodology against the applicable limitations, conditions, and restrictions imposed in the staff's approving SER, and found the analysis to be in accordance.

The purpose of the licensee's analysis was to demonstrate conformance with the 10 CFR 50.46 requirements at the planned power uprate conditions with the ASTRUM method. Important input assumptions, as well as analytical models and analysis methodology for the BE-LBLOCA were provided. Analysis results were also provided, which showed that no design or regulatory limit related to the BE-LBLOCA would be exceeded at the conditions analyzed.

The licensee stated in its July 13, 2007, submittal that both the licensee and its vendor, Westinghouse Electric Company LLC, have ongoing processes which assure that LOCA analyses input values conservatively bound the as-operated plant values for those parameters. The NRC staff finds that this statement, along with the generic acceptance of ASTRUM methodology, provides reasonable assurance that ASTRUM and its BE-LBLOCA analysis apply to MPS3 at its uprated power level.

The licensee provided results of the MPS3 BE-LBLOCA analysis in the LR, assuming that the plant is operating at 3650 MWt, in accordance with the statistical best estimate approach. The licensee correctly assumed a LOOP. The results for calculated PCTs, the maximum local cladding oxidations, and the maximum core-wide cladding oxidations are repeated in the following table:

Parameter	MPS3 power uprate Result	10 CFR 50.46 Limit
Limiting Break Size/Location	DEG/PD	N/A
Cladding Material	ZIRLO	(Cylindrical) Zircaloy or ZIRLO
Peak Cladding Temperature	1781°F	2200°F
Maximum Local Oxidation	3.5%	17.0%
Maximum Total Core-Wide Oxidation	0.12%	1.00%

[156] NUREG/CR-5249, "Quantifying Reactor Safety Margins: Application of Code Scaling, Applicability, and Uncertainty Evaluation Methodology to a Large-Break, Loss-of-Coolant Accident," Idaho National Engineering Laboratory, December, 1989

[157] Regulatory Guide 1.157, "Best Estimate Calculations of Emergency Core Cooling System Performance," US Nuclear Regulatory Commission, May, 1989

[158] WCAP-16009-P-A, "Realistic Large Break LOCA Evaluation Methodology Using the Automated Statistical Treatment of Uncertainty Method," Westinghouse Electric Corporation, 2005

The licensee's analytic limiting local maximum oxidation is 3.5 percent, and was shown to decrease from 3.5 percent from the BOL value to a negligible value at EOL. This result is expected because fuel is generally more susceptible to transient oxidation at the beginning of life. The licensee also confirmed that the sum of pre-transient plus transient oxidation remains below 17 percent at all times in life for the MPS3 fuel.

The limiting core-wide oxidation is based on the limiting hot assembly rod total maximum oxidation. Because the hot assembly rod total maximum oxidation is 0.12 percent, there is significant margin to the regulatory limit, and the NRC staff finds that the licensee has adequately demonstrated that the core-wide oxidation will remain less than one percent.

The licensee stated that break location was generically addressed during the development of the BE-LBLOCA methodology, and that break type and size are specifically considered for the MPS3 transient simulation. The NRC staff reviewed the CQD Methodology and the ASTRUM methodology and confirmed that, in addition to the limiting double-ended guillotine rupture, the method also considers slot breaks in the RCS cold leg. On this basis, the NRC staff finds the licensee's conclusion that the MPS3 PCT-limiting transient is a double-ended cold leg guillotine break acceptable, because uncertainties related to break type and size were included in the modeling approach.

The licensee stated that the MPS3 LBLOCA analysis considers downcomer boiling; WCOBRA/TRAC properly models the effects of downcomer boiling in the transient calculation. The technical evaluation report accompanying the NRC staff's approval of the CQD methodology notes that Westinghouse employs conservative assumptions regarding downcomer and upper plenum entrainment, resulting in conservative PCT assumptions. These methods are also employed in the ASTRUM methodology, and the staff therefore agrees with the licensee's statement, and finds that the licensee has appropriately considered downcomer boiling in its analyses.

Based on its review of the licensee's application of the ASTRUM BE-LBLOCA methodology, the NRC staff concluded that the Westinghouse BE LBLOCA methodology is acceptable for use for MPS3 in demonstrating compliance with the requirements of 10 CFR 50.46(b), operating at the proposed uprated conditions. The staff's conclusion was based on the fact that the MPS3 analysis was conducted within the conditions and limitations, and supporting technical basis, of the NRC-approved Westinghouse BE LBLOCA methodology.

Based on its review of the results of the MPS3 BE LBLOCA analysis, the staff found that the results satisfied the requirement of 10 CFR 50.46(b) based on the uprated power level.

Small Break LOCA and Post-LOCA Long Term Cooling

The small-break LOCA (SBLOCA) includes all postulated pipe ruptures with a total cross-sectional area less than 1.0 square foot. The SBLOCAs analyzed in this section are for those breaks beyond the makeup capability of a single charging pump, and hence, require actuation of the ECCS. The licensee's analyses were performed to demonstrate compliance with the 10 CFR 50.46 requirements for the conditions associated with MPS3, operating at its uprated power level.

In areas where the licensee and its contractors used NRC-approved methods in performing analyses, the NRC staff reviewed relevant material to assure that the license/contractor used the methods consistent with the limitations and restrictions placed on the methods. In addition, the NRC staff considered the effects of the changes in plant operating conditions on the use of these methods to assure that the methods were appropriate for use at the proposed uprated conditions.

The licensee has analyzed the SBLOCA using a methodology consistent with its current licensing basis. The licensee will continue to use the NRC-approved NOTRUMP code, documented in WCAP-10054-P-A, "Westinghouse Small Break LOCA Evaluation Model Using the NOTRUMP Code,"[159] and NRC-approved changes to the methodology[160] to evaluate the SBLOCA. The methodology includes calculation of the system thermal hydraulic response using the NOTRUMP code, and the effects of fuel rod heat up using the SBLOCTA code, which in turn demonstrates the acceptability of peak clad temperature, cladding oxidation, and hydrogen generation results. These methods contain conservative assumptions in order to develop analytic results in accordance with the requirements set forth in Appendix K to 10 CFR 50.

For the MPS3 SBLOCA analysis, the licensee analyzed a spectrum of cold leg breaks that included 1.5, 2, 3, 4, and 6-inch breaks. The licensee also considered an 8.75-inch accumulator line break, and found that the 4-inch cold leg break produced the limiting peak clad temperature. The NRC has, in the past, challenged the coarseness of the NOTRUMP break spectrum; however, the licensee's results, as shown below, demonstrate a peak clad temperature that maintains significant margin to both the large break LOCA results and the 2200 °F acceptance criterion. Because the predicted PCTs are less than 1700 ° F, the NRC staff accepts the licensee's break spectrum selected for analysis.[161]

SMALL BREAK LOCA ANALYSIS RESULTS – Millstone Unit 3

Parameter	Results	10 CFR 50.46 Limits
Limiting Break Size	4.0-in	N/A
Peak Clad Temperature	1193 °F	2200° F
Maximum Local Oxidation	0.05%	17.0%
Maximum Core-Wide Oxidation	0.01%	1.0%

[159] WCAP-10079-P-A, "NOTRUMP – A Nodal Transient Small Break and General Network Code," Westinghouse Electric Corporation, August, 1985;
WCAP-10054-P-A, "Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code," Westinghouse Electric Corporation, August, 1985; and
WCAP-11145-P-A, "Westinghouse Small Break LOCA ECCS Evaluation Model Generic Study with the NOTRUMP Code," Westinghouse Electric Corporation, October, 1986

[160] WCAP-10054-P-A, Addendum 2, Revision 1, "Addendum to the Westinghouse Small Break ECCS Evaluation Model Using the NOTRUMP Code: Safety Injection into the Broken Loop and COSI Condensation Model," Westinghouse Electric Corporation, July, 1997 and WCAP-14710-P-A, "1-D Heat Conduction Model for Annular Fuel Pellets," Westinghouse Electric Corporation, May, 1998

[161] LTR-NRC-06-44, "Response to NRC Request for Additional Information on the Analyzed Break Spectrum for the Small Break Loss of Coolant Accident NOTRUMP Evaluation Model," Westinghouse Electric Corporation, July, 2006 (ADAMS Accession No. ML062000027)

The NRC staff reviewed the licensee's demonstration evaluations of the ECCS SBLOCA performance analyses, performed in accordance with the NOTRUMP SBLOCA methodology, for MPS 3 operating at its proposed, uprated power level of 3650 MWt. These specific analyses, when approved herein, will be acceptable and specifically applicable to MPS3 operated with the fuel(s) identified in the licensing report of the license amendment request, dated July 13, 2007. The SBLOCA analyses for MPS3 were conducted assuming that the plant uses cores containing ZIRLO clad uranium oxide fuel assemblies.

LOCA Forces

The licensee performed LOCA hydraulic forces analyses at the uprated power level to determine the forces acting on the reactor pressure vessel and internals, fuel, loop piping, SG, and RCCA guide tubes. The results of these analyses were used as input to various structural analyses in order to quantify design margins from component-specific calculations.

Consistent with the licensee's current licensing basis, these calculations were performed using a "leak before break" (LBB) approach, as the licensee obtained an exemption to exclude primary loop pipe ruptures from the design basis for MPS3. The licensee therefore considered a 10-inch accumulator line connection to the cold leg, and the 12-inch RHR and 14-inch pressurizer surge line connections on the hot leg.

The licensee evaluated the applicability of the LBB approach as described in Section 2.1.6 of this SE. The licensee's evaluations employed the MULTIFLEX code; the staff reviewed the safety evaluation for the original MULTIFLEX topical report.[162] The restrictions contained in the safety evaluation specified acceptable modeling approaches, and found the code acceptable for modeling 4-loop PWRs. No restrictions were found which would preclude the code from being acceptable for MPS3's uprated calculations.

The evaluation of the mechanical components and their acceptability for uprated conditions is addressed in Section 2.2 of this SE.

Post-LOCA Subcriticality and Long-Term Cooling

To support its proposed power uprate, the licensee performed calculations to demonstrate post-LOCA sub-criticality and acceptable long-term cooling.

The post-LOCA sub-criticality calculations were performed to demonstrate compliance, in part, with 10 CFR 50.46(b)(5), which requires a demonstration of acceptable long-term cooling capability. The sub-criticality calculation demonstrates that the core will remain sufficiently borated to preclude an inadvertent return to criticality. The licensee's calculation is performed in accordance with WCAP-8339, "Westinghouse Emergency Core Cooling System Evaluation Model – Summary,"[163] and containment sump boron concentrations were used to develop a

[162] WCAP-8708-P-A, "MULTIFLEX, A FORTRAN-IV Computer Program for Analyzing Thermal-Hydraulic-Structure System Dynamics," Westinghouse Electric Corporation, September, 1977

[163] WCAP-8339, "Westinghouse Emergency Core Cooling System Evaluation Model – Summary," Westinghouse Electric Corporation, June, 1974

core reactivity limit that was confirmed as part of the Westinghouse Reload Safety Evaluation Methodology.[164]

The licensee's subcriticality calculations employed assumptions that minimized available boron concentrations and maximized available boron dilution sources. The licensee also assumed uniform boron mixing in the sump, and the sump boron concentration was calculated as a function of pre-trip RCS conditions. The licensee calculated a post-LOCA subcriticality boron limit curve for SPU plant conditions, and stated that cycle-specific reload safety evaluations will ensure that the core will remain subcritical following a LOCA. The staff finds that the licensee adequately accounts for post-LOCA subcriticality following a LOCA, because the licensee has calculated a conservative post-LOCA sump boron concentration and uses NRC-approved reload methods to confirm that this concentration of boron will keep the core subcritical.

The licensee's post-LOCA long term cooling analysis was provided in their letter dated July 13, 2007.[165] The post-LOCA long-term core cooling analysis addresses the potential for boric acid precipitation and the ability to maintain long-term decay heat removal, and demonstrates compliance with 10 CFR 50.46(2)(b)(4) and (b)(5), regarding a coolable geometry and long-term cooling capability.

The boric acid precipitation calculation model considered the effects of core voiding on liquid mixing volume, and employed conservative available mixing volume assumptions with respect to available lower plenum volume availability and potential negative effects of loop pressure drop. Additional assumptions concerning the calculations are given in 2.8.5.6.3.2.5 of the licensee's July 12, 2007, submittal.

The limiting LBLOCA, analyzed by the licensee, resulted in a 3 to 5 hour timeframe to establish simultaneous hot leg and cold leg safety injection. This evaluation assumed boric acid solubility calculations at 14.7 psia, and the licensee indicated that these calculations apply to RCS pressures up to 30 psia, despite that the boric acid solubility above the atmospheric boiling point of a saturated boric acid and water solution is not credited. The analysis shows that 5 hours is available to complete action to switch to hot-leg injection and dilute the boric acid solution.

The NRC staff also reviewed the results of the SBLOCA analyses, which were performed at 120 psia. These calculations considered less core voiding, a lower heat of vaporization, and did not credit SI subcooling to reduce core boiloff. Boric acid solubility for the saturation temperature of water at 30 psig was credited. The results demonstrate adequate dilution provided initiation of simultaneous injection by 5 hours.

The licensee evaluated the effects of an early switchover to hot leg or simultaneous injection. The evaluation considered the hot leg entrainment threshold and core cooling. The evaluations demonstrated that significant hot leg entrainment would not occur after 80 minutes, and the licensee's calculations demonstrated that either hot leg or cold leg injection flows are sufficient to provide core cooling flow 3 hours after a LOCA.

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[164] WCAP-9273-P-A, "Westinghouse Reload Safety Evaluation Methodology," Westinghouse Electric Corporation, July, 1985.
[165] ADAMS Accession No. ML072000281

The licensee has demonstrated acceptable post-LOCA long term cooling performance at the uprated power level for MPS3. The licensee's approach is consistent with guidance contained in the references[166] listed below, and follows a similar approach to that used to support a previous uprate.[167]

In consideration of this information, the NRC staff concludes that the licensee's analysis adequately demonstrates acceptable post-LOCA subcriticality and long-term cooling capability. These evaluations demonstrate compliance with the requirements of 10 CFR 50.46(b)(4) and (b)(5).

Conclusion

The NRC staff has reviewed the licensee's analyses of the LOCA events and the ECCS. The NRC staff concludes that the licensee's analyses have adequately accounted for operation of the plant at the proposed power level and that the analyses were performed using acceptable analytical models. The NRC staff further concludes that the licensee has demonstrated that the RPS and the ECCS will continue to ensure that the PCT, total oxidation of the cladding, total hydrogen generation, and changes in core geometry, and long-term cooling will remain within acceptable limits. Based on this, the NRC staff concludes that the plant will continue to meet the requirements of GDCs 4, 27, 35, and 10 CFR 50.46 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the LOCA.

2.8.5.7 Anticipated Transients Without Scrams

Regulatory Evaluation

Anticipated transients without scram (ATWS) is defined as an anticipated operational occurrence followed by the failure of the reactor portion of the protection system specified in GDC-20. The regulation at 10 CFR 50.62 requires that:

(1) Each PWR must have equipment that is diverse from the RTS to automatically initiate the auxiliary (or emergency) feedwater system and initiate a TT under conditions indicative of an ATWS. This equipment must perform its function in a reliable manner and be independent from the existing RTS; and

(2) Each PWR manufactured by Combustion Engineering (CE) or Babcock and Wilcox (B&W) must have a diverse scram system (DSS). This scram system

[166] Gramm, R.A., US Nuclear Regulatory Commission, Letter to J.A. Gresham, Westinghouse Electric Corporation, "Suspension of NRC Approval for Use of Westinghouse Topical Report CENPD-254-P, 'Post LOCA Long Term Cooling Model' Due to Discovery of Non-Conservative Modeling Assumptions During Calculations Audit," August 1, 2005, and Peters, S.E., US Nuclear Regulatory Commission, Memorandum to S.L. Rosenberg, US Nuclear Regulatory Commission, "Summary of August 23, 2006, Meeting With the Pressurized Water Reactor Owners Group to Discuss the Status of Program to Establish Consistent Criteria for Post Loss of Coolant Accident Calculations," October 3, 2006. (ADAMS Accession Nos. ML051920310 and ML062690017, respectively)

[167] Letter L-05-112, "Responses to a Request for Additional Information in Support of License Amendment Nos. 302 and 173," First Energy Nuclear Operating Company, July 8, 2005, and Letter L-05-169, "Responses to a Request for Additional Information in Support of License Amendment Request Nos. 302 and 173," First Energy Nuclear Operating Company, November 21, 2005. (ADAMS Accession Nos. ML051940575, and ML053290133, respectively)

must be designed to perform its function in a reliable manner and be independent from the existing RTS.

The NRC staff's review was conducted to ensure that: (1) the above requirements are met; and (2) the setpoints for the AMSAC and DSS remain valid for the proposed SPU. In addition, for plants where a DSS is not specifically required by 10 CFR 50.62, the NRC staff verified that the consequences of an ATWS are acceptable. The acceptance criterion is that the peak primary system pressure should not exceed the ASME Service Level C limit of 3200 psig. The peak ATWS pressure is primarily a function of the MTC and the primary system relief capacity. The NRC staff reviewed: (1) the limiting event determination; (2) the sequence of events; (3) the analytical model and its applicability; (4) the values of parameters used in the analytical model; and (5) the results of the analyses. The NRC staff reviewed the licensee's justification of the applicability of generic vendor analyses to its plant and the operating conditions for the proposed SPU. Review guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The final ATWS rule, 10 CFR 50.62 (c)(1), requires the incorporation of a diverse actuation of the AFW system and the TT for Westinghouse-designed plants. The installation of the NRC-approved AMSAC design satisfies the rule. To remain consistent with the basis of the final ATWS rule, the peak RCS pressures predicted in the ATWS evaluation should be comparable to the peak RCS pressures reported for generic ATWS analyses, conducted by Westinghouse in 1979 (NS-TMA-2182),[168] and must not exceed the ASME Service Level C limit of 3200 psig.

The limiting ATWS events, with respect to RCS pressurization, are the LOL and LONF events. These events were re-analyzed in the manner of the analyses reported in NS-TMA-2182. The staff accepts this approach since the NS-TMA-2182 analyses include four-loop Westinghouse plants with Model F SGs. Furthermore, the licensee used LOFTRAN,[169] the same code that was used in the original studies. The results indicated that MPS3, with the Model F SGs, produced the peak RCS pressures that are consistent with the results of NS-TMA-2182.

The peak RCS pressure produced by a LOL ATWS in a plant of the MPS3 design is 2902 psia. This is the peak pressure predicted for the plant before the power uprate. Increasing the rated thermal power, to account for the uprating, is expected to result in a higher peak RCS pressure. According to the sensitivity study results in NS-TMA-2182, increasing power by 7 percent would increase the peak RCS pressure by about 154 psi. Therefore, NS-TMA-2182 predicts a peak RCS pressure, for an LOL ATWS, in a plant of the MPS3 design, to be about 3056 psia. The licensee's analysis result is 3105 psia.

The staff agrees with the licensee assumptions and methods, and concludes that this is an acceptable means to show compliance with the analytical basis of the ATWS Rule, for MPS3 operating under power uprate conditions.

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[168] NS-TMA-2182, letter from T.M. Anderson, Westinghouse, to S.H. Hanauer, NRC, "ATWS Submittal," dated December 30, 1979

[169] WCAP-7907-P-A (Proprietary), WCAP-7907-A (Nonproprietary), April 1984, Burnett, T. W. T., et al., "LOFTRAN Code Description"

Conclusion

The NRC staff has reviewed the information submitted by the licensee related to ATWS and concludes that the licensee has adequately accounted for the effects of the proposed SPU on ATWS. The NRC staff concludes that the licensee has demonstrated that the AMSAC will continue to meet the requirements of 10 CFR 50.62 following implementation of the proposed SPU. Additionally, the licensee has demonstrated, as explained above, that the peak primary system pressure following an ATWS event will remain below the acceptance limit of 3200 psig. Therefore, the NRC staff finds the proposed SPU acceptable with respect to ATWS.

2.8.6 Fuel Storage

2.8.6.1 New Fuel Storage

Regulatory Evaluation

Nuclear reactor plants include facilities for the storage of new fuel. The quantity of new fuel to be stored varies from plant to plant, depending upon the specific design of the plant and the individual refueling needs. The NRC staff's review covered the ability of the storage facilities to maintain the new fuel in a subcritical array during all credible storage conditions. The review focused on the effect of changes in fuel design on the analyses for the new fuel storage facilities. The NRC's acceptance criteria are based on GDC 62, insofar as it requires the prevention of criticality in fuel storage systems by physical systems or processes, preferably utilizing geometrically safe configurations. Specific review criteria are contained in SRP Section 9.1.1.

Technical Evaluation

The current new fuel storage analyses for MPS3 has been established at 5.0 weight percent uranium-235. This supports the uprate conditions. There are also no changes in fuel design characteristics that would affect the criticality analyses for new fuel storage. Therefore, the staff finds that the uprate will not affect the ability to store new fuel in a subcritical configuration.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effect of the new fuel on the analyses for the new fuel storage facilities and concludes that the new fuel storage facilities will continue to meet the requirements of GDC 62 following implementation of the proposed SPU. Therefore, the NRC staff finds the proposed SPU acceptable with respect to the new fuel storage.

2.8.7 Additional Review Areas (Reactor Systems)

NSSS/BOP Tanks, Pumps, Valves, and Heat Exchangers

The licensee conducted a review of tanks, pumps, valves, and heat exchangers from the RCS, RHR system, CVCS, low pressure safety injection, and high pressure safety injection systems that are important to safety. The licensee's review included confirmation that each component was designed to withstand changes in pressure and temperature that would be necessary to

withstand the proposed uprated operating conditions. The staff reviewed LR Tables 2.8.7.1-1-4, which contain the heat exchangers, pumps, valves, and tanks evaluated by the licensee. The staff reviewed the piping and instrumentation diagrams in the MPS3 UFSAR to confirm that the necessary components were considered. The staff found no omissions. On this basis, the staff concludes that the licensee's evaluation has adequately accounted for the effects that the uprated operating conditions will have on the listed components, and finds the proposed uprate acceptable with respect to pressure and temperature effects on NSSS/BOP heat exchangers, pumps, valves, and tanks.

Natural Circulation Cooldown

NRC Review Standard RS-001 does not explicitly provide guidance for post-uprate licensing basis reviews for natural circulation. As a part of the original MPS3 licensing basis, however, the licensee provided the NRC with information documenting compliance with NRC BTP RSB 5-1, "Design Requirements of the Residual Heat Removal System." The BTP required that test programs for PWRs include tests with supporting analyses to: (1) confirm that adequate mixing of borated water added prior to or during cooldown can be achieved under natural circulation conditions and permit estimation of the times required to achieve such mixing; and (2) confirm that the cooldown under natural circulation conditions can be achieved with the limits specified in the EOPs. In addition, the plant is to be designed so that the reactor can be taken from normal operating conditions to cold shutdown using only safety-grade systems.

The NRC staff found that a comparison of performance to that of previously tested plants of similar design may be substituted for these tests. The licensee provided such comparisons to the NRC relating to a boron mixing and cooldown test that was performed at Diablo Canyon Unit 1 (DCPS1), which the NRC staff found acceptable by letter dated October 18, 1988.

The licensee noted the following in comparison to reactor system design between MPS3 and DCPS1:

(1) The general configuration of piping and components in each RCL is the same;

(2) DCPS1 has a longer SG tube bundle, resulting in a 5-10 percent higher driving head than at MPS3;

(3) Hydraulic resistance coefficients for DCPS1 were compared to MPS3 for normal operations to obtain a flow ratio;

(4) DCPS1 has a smaller vessel inlet nozzle radius than MPS3;

(5) The DCPS1 test was run with STD fuel, and MPS3 will use RFAs;

(6) RCP impeller designs are similar between the two plants; and

(7) The MPS3 power uprate analysis considered 0-10 percent SG tube plugging.

The licensee concluded that the higher core power level at MPS3 will result in about 3% more flow than observed at DCPS1. The staff reviewed the licensee's evaluation and finds that the

configuration of MPS3 remains largely the same as previously evaluated, and agrees with the licensee's conclusion that the 1987 comparison between MPS3 and DCPS1 remains applicable.

Boron mixing evaluations were performed in support of the MPS3 uprate. Safety grade cold shutdown analyses predicted a boration time in the 2.5 to 3.5 hour range, and a boron mixing evaluation demonstrated that sufficient natural circulation flow exists to adequately mix the boron that is added to the RCS.

The licensee stated that cooldown limits given in the Westinghouse Owners Group Emergency Response Guidelines and background document are not changed by the uprate, because the same cooldown rate requirements apply for natural circulation procedures before and after the uprate. The license further related cooldown capability to similarities in plant configuration between MPS3 and DCPS1, which also remain unchanged. The safety grade cold shutdown analysis evaluated by the NRC staff in Section 2.8.4.4 shows that sufficient AFW is available to support a natural circulation cooldown to cold shutdown at MPS3.

At MPS3, pressure control and depressurization capability are similar to DCPS1, the licensee stated, due to design similarities in the RCS and CVCS design. The systems and components were evaluated at power uprate conditions to confirm that RCS pressure control can be maintained via the pressurizer power operated relief valves, the pressurizer auxiliary spray, and two pressurizer backup heater units to sufficiently depressurize the reactor to commence RHR operation.

Based on its review of the licensee's comparison, the staff concludes that the comparison is reasonable, and the MPS3 design configuration remains sufficiently analogous to DCPS1 that the DCPS1 test remains applicable to MPS3 at uprated conditions.

Mid-Loop Operation

The licensee reviewed the current licensing basis at MPS3 to determine whether identified actions taken to preclude loss of decay heat removal during non-power operation in response to Generic Letter 88-17, "Loss of Decay Heat Removal,"[170] were affected by the proposed power uprate. The licensee concluded that the uprated conditions have no impact on the existing instrumentation that is utilized to monitor the RCS level and RHR performance during mid-loop operation, do not require any additional instrumentation to monitor reduced inventory operation, and have no impact on the availability of water sources credited in the shutdown risk assessment.

The NRC staff reviewed the licensee's Expeditions Actions and Programmed Enhancements in response to GL 88-17, and the corresponding NUMARC 91-06 Guidelines[171] that were developed in response and determined that each item was either unaffected by the power uprate, or are evaluated each cycle and revised as necessary, and hence will reflect the uprated power level. On this basis, the NRC staff finds that mid-loop operation will be acceptable at MPS3 at the uprated power level.

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[170] Reference: Generic Letter 88-17, "Loss of Decay Heat Removal," US Nuclear Regulatory Commission, October, 1988.

[171] NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," Nuclear Management and Resources Council, 1991

VIPRE/RETRAN Implementation

As a part of the power uprate implementation request, the licensee has requested to transition its Chapter 15 AOO/Accident Analysis Methodology from THINC-IV/LOFTRAN to VIPRE/RETRAN. The NRC staff reviewed the licensee's implementation of these methods to confirm that each method is implemented consistent with the conditions and limitations specified in the SER documenting the NRC's approval of each method.

The basis for the NRC staff's review comes from several sources. First, the licensee provided a description of each method in Section 2.8.5.0 of the LR. This description included a list of conditions and limitations for each method. As necessary, the licensee provided additional justification for using the method to demonstrate compliance with the conditions and limitations. Second, the NRC staff reviewed the safety evaluation report documenting the technical basis for the staff's approval of each method to confirm that the licensee properly identified the conditions and limitations. Finally, the NRC staff reviewed the licensing topical reports and supporting documentation associated with each method. The review was performed to confirm that the conditions and limitations adequately account for the uprated conditions at MPS3.

VIPRE

VIPRE is a subchannel thermal-hydraulic code used to evaluate local conditions for departure from nuclear boiling analysis. Its input boundary conditions are coolant inlet flow rate, enthalpy and pressure. The code can accommodate spatial and temporal variations in core power. Consistent with the Westinghouse analytical approach, reactor system inputs are obtained from RETRAN, neutronic inputs are obtained from the Advanced Nodal Code, and fuel performance inputs are obtained from the fuel Performance and Design code.

In its generic approval of the VIPRE code, the NRC staff issued four conditions/limitations to the VIPRE method:

(1) Selection of the appropriate CHF correlation, DNBR limit, engineered hot channel factors for enthalpy rise and other fuel-dependent parameters for a specific plant application should be justified with each submittal.

(2) Reactor core boundary conditions determined using other computer codes are generally input into VIPRE for reactor transient analyses. These inputs include core inlet coolant flow and enthalpy, core average power, power shape and nuclear peaking factors. These inputs should be justified as conservative for each use of VIPRE.

(3) The NRC staff's generic SER for VIPRE set requirements for use of new CHF correlations with VIPRE. Westinghouse has met these requirements for using the WRB-1, WRB-2, and WRB-2M correlations. The DNBR limit for WRB-1 and WRB-2 is 1.17. The WRB-2M correlation has a DNBR limit of 1.14. Use of other CHF correlations not currently included in VIPRE will require additional justification.

(4) Westinghouse proposes to use the VIPRE code to evaluate fuel performance following postulated DBAs, including beyond-CHF heat transfer conditions.

These evaluations are necessary to determine the extent of core damage and to ensure that the core maintains a coolable geometry in the evaluation of certain accident scenarios. The NRC staff's generic review of VIPRE did not extend to post CHF calculations. VIPRE does not model the time-dependent physical changes that may occur within the fuel rods at elevated temperatures. Westinghouse proposes to use conservative input in order to account for these effects. The NRC staff requires that appropriate justification be submitted with each usage of VIPRE in the post-CHF region to ensure that conservative results are obtained.

Selection of Appropriate CHF Correlation

The licensee proposes to implement the WRB-2M DNB correlation with a correlation limit of 1.14. This correlation and its limit are specifically applicable to fuel assemblies with mixing vane grid designs similar to the RFA fuel type. Use of the correlation is limited to applicable conditions that are reflective of the experimental database that supports the WRB-2M correlation.

The licensee proposes to use VIPRE and the WRB-2M correlation for those transients that are analyzed using the RTDP. The licensee stated in Section 2.8.5.3 of its LR that, where transient conditions are predicted that fall outside the validated range of the WRB-2M correlation, the W-3 or WRB-2 correlation will be used in concert with the STDP.

The licensee stated that the use of plant-specific hot channel factors and other fuel dependent parameters in the DNB analysis for the MPS3 RFA fuel were justified using the same methodologies as for previously-approved safety evaluations of other Westinghouse four-loop plants using the same fuel design. The NRC staff finds that this statement alone does not provide adequate justification that Condition/Limitation 1 has been satisfied.

However, the NRC staff reviewed the licensee's fuel system mechanical design, nuclear design, thermal-hydraulic design, and transient and accident analyses, and found them acceptable for uprated conditions. As a part of the staff's review, the enthalpy rise hot channel factors and other fuel-dependent parameters were found to be acceptable for uprated conditions, because the licensee's NRC-approved, reload-specific confirmation process will assure that each core design will remain bounded by the evaluated fuel system parameters, and because the accident and transient analyses demonstrated acceptable results using the evaluated fuel system parameters. On this basis, the NRC staff finds that the plant-specific fuel system design parameters proposed for the MPS3 uprate are justified, and that Condition/Limitation 1 is satisfied.

Input of Justified Boundary Conditions

The licensee stated that the core boundary conditions for the VIPRE calculations for the MPS3 fuel are all generated from NRC-approved codes and analysis methodologies. These codes and methodologies are listed in the first paragraph of Section 2.8.7.4.1 of this Safety Evaluation. The licensee will verify the conservatism and applicability of the boundary conditions for each reload as a part of the licensee's NRC-approved reload method. The staff finds that the use of NRC-approved codes and methodologies provides acceptable input parameters, and that the

cycle-specific confirmation of the parameters adequately justifies their use. The staff therefore concludes that Condition/Limitation 2 is satisfied.

Use of Acceptable DNB Correlations

For most transients, the licensee used the WRB-2M correlation with VIPRE. In several cases, the use of the WRB-2 correlation was used because predicted thermal-hydraulic conditions fell outside the validated range of the WRB-2M correlation. When WRB-2 was used, the licensee used the appropriate DNB limit (1.17). Hence, the use of these two correlations is acceptable. Appropriate justification of the use of the W-3 DNBR correlation, which was used in VIPRE analyses of the Uncontrolled RCCA Withdrawal from Subcritical sequence, and in the steam line break accident, was not provided.

The W-3 DNBR correlation, however, was used by the NRC staff in its benchmark comparisons of the VIPRE code to determine the acceptability of VIPRE for Westinghouse safety evaluations. In its SER for Westinghouse PWR applications of VIPRE, the staff also noted the following:

> For reactor system conditions outside the range of the fuel-specific CHF correlations, Westinghouse will use the W-3 correlation in the form developed for smooth tubes consistent with the approved main-steam-line-break methodology described in WCAP-9226. Westinghouse will apply a DNBR limit of 1.3 to W-3 predictions above 1000 psia and a DNBR limit of 1.45 to W-3 predictions below 1000 psia.

The staff notes that the licensee correctly observed these limits in its transient analyses employing the W-3 correlation.

The staff concludes that appropriate limits have been used for each DNB correlation employed in the VIPRE analyses. Therefore, the staff finds that the licensee has satisfied Condition/Limitation 3.

Limited Post-CHF Modeling

The licensee used VIPRE to model post-CHF fuel performance in one transient sequence: the locked rotor transient. The results of the analysis demonstrated significant margin to allowable limits, as discussed in Section 2.8.5.3.2 of this SE. The licensee also listed the conservative assumptions employed in the VIPRE fuel rod modeling. These assumptions included the following:

(1) DNB was assumed to occur at the beginning of the transient;

(2) Film boiling was calculated using the BST correlation;

(3) The Baker-Just correlation accounted for heat generation in fuel cladding due to zirconium-water reaction;

(4) Fuel rod input was based on the maximum fuel temperature at the given power;

(5) The hot spot power factor was equal to or greater than the design linear heat rate; and

(6) Uncertainties were applied to the initial operating conditions in the limiting direction.

Section 2.8.5.3 of the LR provided the following information regarding the evaluation of this transient:

(1) RETRAN was used to calculate loop and core flows, time of reactor trip, nuclear power transient, primary system transient, and temperature transients.

(2) VIPRE was used to calculate peak clad temperature using RETRAN-calculated nuclear power, RCS temperature (enthalpy), pressure, and flow.

(3) For the peak pressure case, initial primary pressure was increased from the nominal value of 2250 to 2300 to account for plant uncertainties. PORVs and pressurizer sprays were assumed to be disabled, as were feedwater flow control and steam dumps. PSV lift setpoints were increased by 3 percent.

(4) Fluid properties were evaluated at the film temperature.

(5) At the beginning of the transient, the gap heat transfer coefficient was increased, which resulted in a release of stored thermal energy in the fuel to the cladding.

In evaluation of the licensee's compliance with Condition/Limitation 4, the staff considered information contained in the SE approving VIPRE. In the SE, the staff observed that the Bishop-Sandberg-Tong heat transfer correlation and the Baker-Just correlation were both previously approved for use in FACTRAN. The staff also acknowledged Westinghouse's intent to use VIPRE to calculate post-CHF fuel heatup, following postulated design-basis non-LOCA accidents. The example provided was the failure of a reactor coolant pump drive shaft, which was also evaluated for a four-loop PWR and compared to FACTRAN results with reasonable agreement. In the analyses supporting the MPS3 uprate, differences in PCT predictions for the locked rotor transient are attributed to improvements in the fuel rod performance code capability from PAD3.0 to PAD4.0, which the staff finds reasonable.

The staff presently acknowledges that, of the assumptions listed above, the use of a maximum fuel rod temperature, a high hot spot power factor, and increases in gap heat transfer coefficient are assumptions that will conservatively increase cladding temperature. Therefore, the staff concludes that the licensee has submitted the required, appropriate justification to use VIPRE for analysis of the locked-rotor transient, and that Limitation/Condition 4 is satisfied.

RETRAN

RETRAN is a flexible, general purpose, thermal/hydraulic computer code that is used to evaluate the effect of various upset reactor conditions on the RCS. The code models the reactor coolant as a single phase or as two equilibrium phases with the exception that a non-equilibrium pressurizer component can be included. Conductive heat structures can be described, including the fuel elements in the reactor core. Changes in reactor power from neutron kinetics and decay heat considerations are calculated to occur with time.

The staff approved Westinghouse application of the RETRAN method to replace the LOFTRAN code to perform non-loss of coolant accident safety analysis. Three conditions were provided regarding its application to Westinghouse PWRs.

(1) The transients and accidents that Westinghouse proposes to analyze with RETRAN are listed in the NRC staff's SER of RETRAN, and the NRC staff review of RETRAN usage by Westinghouse was limited to this set. Use of the code for other analytical purposes will require additional justification.

(2) WCAP-14882 describes modeling of Westinghouse designed 4-, 3-, and 2-loop plants of the type that are currently operating. Use of the code to analyze other designs, including the Westinghouse AP600, will require additional justification.

(3) Conservative safety analyses using RETRAN are dependent on the selection of conservative input. Acceptable methodology for developing plant-specific input is discussed in WCAP-14882, and in the Westinghouse Reload Safety Evaluation Methodology. Licensing applications using RETRAN should include the source of and justification for the input data used in the analysis.

Use of RETRAN to Analyze Acceptable Transients

The staff reviewed the RETRAN-analyzed transients listed by the licensee in Section 2.8.5.0 and concluded that the transients were all included in the list of transients evaluated by the NRC staff as documented in the SE for WCAP-14882. The licensee does not propose to analyze any transients that are not included in the list, hence, no further justification is required.

Use of RETRAN at an Acceptable Plant

MPS3 is a four loop Westinghouse PWR and was operating at the time that the NRC staff evaluated RETRAN for Westinghouse use, and the staff concludes on this basis that no further justification is required.

Selection of Appropriate Input Parameters

The licensee stated that assurance that the RETRAN input data is conservative for MPS3 is provided via Westinghouse's use of transient-specific analysis guidance documents, which provide the basis for collection of conservative plant-specific input values from responsible DNC and Westinghouse sources. Consistent with the Westinghouse Reload Evaluation Methodology, the safety analysis input values used in the MPS3 analyses were selected to conservatively bound the values expected in subsequent operating cycles. In consideration of this statement, the staff is reasonably assured that conservative input has been selected for the MPS3 uprate analyses.

Conclusion

The NRC staff reviewed the licensee's implementation of VIPRE and RETRAN for use to analyze uprated conditions at MPS3. The staff's evaluation of the specific transient analyses is contained in Section 2.8.5 of this safety evaluation. Based on the fact that the licensee has satisfied the conditions and limitations specified for each method, and on acceptable transient analysis results as provided in Section 2.8.5, the staff concludes that the licensee may implement VIPRE and RETRAN for transient analysis at MPS3 as described in the LR.

2.9 Source Terms and Radiological Consequences Analyses

2.9.1 Source Terms for Radwaste Systems Analyses

Regulatory Evaluation

The NRC staff reviewed the radioactive source term associated with the SPU to ensure the adequacy of the sources of radioactivity used by the licensee as input to calculations to verify that the radioactive waste management systems have adequate capacity for the treatment of radioactive liquid and gaseous wastes. The NRC staff's review included the parameters used to determine: (1) the concentration of each radionuclide in the reactor coolant; (2) the fraction of fission product activity released to the reactor coolant; (3) concentrations of all radionuclides other than fission products in the reactor coolant; (4) leakage rates and associated fluid activity of all potentially radioactive water and steam systems; and (5) potential sources of radioactive materials in effluents that are not considered in the MPS3 UFSAR related to liquid waste management systems and GWMSs. The NRC staff's acceptance criteria for source terms are based on: (1) 10 CFR Part 20, insofar as it establishes requirements for radioactivity in liquid and gaseous effluents released to unrestricted areas; (2) 10 CFR Part 50, Appendix I, insofar as it establishes numerical guides for design objectives and LCO to meet the ALARA criterion; and (3) GDC 60, insofar as it requires that the plant design include means to control the release of radioactive effluents. Specific review criteria are contained in SRP Section 11.1.

Technical Evaluation

The core isotopic inventory is a function of the core power level, while the reactor coolant isotopic activity concentration is a function of the core power level, the migration of radionuclides from the fuel, radioactive decay and the removal of radioactive material by coolant purification systems. Radiation sources in the reactor coolant include activation products, activated corrosion products and fission products. During reactor operation, some stable isotopes in the coolant passing through the core become radioactive (activated) as a result of nuclear reactions. For example, the non-radioactive isotope oxygen-16 (O-16) is activated to become radioactive nitrogen-16 (N-16) by a neutron-proton reaction as it passes through the neutron-rich core at power. The increase in the activation of the water in the core region is in approximate proportion to the increase in thermal power.

The licensee stated, in Section 2.10.1.2.4.2 of the Stretch Power Uprate LR, that there will be no changes, as a result of the SPU, to the existing gaseous and liquid radioactive waste systems design, plant operating procedures or waste inputs as defined by NUREG-0017, Revision 1.[172] Therefore, a comparison of releases can be made based on current vs. SPU inventories and radioactivity concentrations in the reactor coolant, secondary coolant, and steam. As a result, the licensee states, and the NRC staff agrees, that the impact of the SPU on radwaste releases and Appendix I doses can be estimated using scaling techniques.

The licensee used scaling techniques, based on NUREG-0017, Revision 1 methodology, to assess the impact of SPU on radioactive gaseous and liquid effluents at MPS3. Use of the

[172] NUREG-0017, "Calculation of Releases of Radioactive Materials in Gaseous and Liquid Effluents from Pressurized Water Reactors (PWRs)", Revision 1

adjustment factors presented in NUREG-0017, Revision 1 allows development of coolant activity scaling factors to estimate SPU conditions.

The licensee's SPU analysis used the plant core power operating history during the years 2001 to 2005, the reported gaseous and liquid effluent and off-site dose calculation data during that period, NUREG-0017, Revision 1, equations and assumptions, and conservative methodology to estimate the impact of operation at the analyzed SPU core power level. The results were then compared to the comparable data from current operation on radioactive gaseous and liquid effluents and the calculated off-site doses from normal operation.

Conclusion

The NRC staff has reviewed the radioactive source term associated with the proposed SPU and concludes that the proposed parameters and resultant composition and quantity of radionuclides are appropriate for the evaluation of the radioactive waste management systems. The NRC staff further concludes that the proposed radioactive source term meets the requirements of 10 CFR Part 20, 10 CFR Part 50, Appendix I, and GDC-60. Therefore, the NRC staff finds the proposed SPU acceptable with respect to source terms.

2.9.2. Radiological Consequences Analyses Using Alternative Source Terms

Regulatory Evaluation

The licensee reviewed the following DBA radiological consequences analyses to determine the impact of the SPU:

(1) Loss-of-Coolant Accident (LOCA);

(2) Fuel Handling Accident (FHA);

(3) Steam Generator Tube Rupture (SGTR);

(4) Main Steam Line Break (MSLB);

(5) Locked Rotor Accident (LRA);

(6) Rod Control Cluster Assembly (RCCA) Ejection Accident (REA); and

(7) Small Line Break Outside Containment (SLBOC).

The NRC staff's review for each accident analysis included: (1) the sequence of events; and (2) models, assumptions, and values of parameter inputs used for the calculation of the total effective dose equivalent (TEDE).

The acceptance criteria for radiological consequences analyses using an AST are based on:

- 10 CFR 50.67, insofar as it describes reference values for radiological consequences of a postulated maximum hypothetical accident;

- RG 1.183,[173] insofar as it describes accident specific dose guidelines for events with a higher probability of occurrence; and

- GDC 19, insofar as it requires that adequate radiation protection be provided to permit access and occupancy of the CR under accident conditions without personnel receiving radiation exposures in excess of 5 rem TEDE, as defined in 10 CFR 50.2, for the duration of the accident.

Specific review criteria are contained in SRP Section 15.0.1, and guidance from Matrix 9 of RS-001.

Technical Evaluation

To determine the effect of the SPU on the design basis radiological analyses, the licensee reanalyzed the following accidents: LOCA, FHA, SGTR accident, MSLB accident, LRA, REA, and the SLBOC. The licensee performed radiological consequence analyses for the various accidents using input assumptions consistent with the proposed SPU conditions. As appropriate, the licensee determined the TEDE at the Exclusion Area Boundary (EAB) for the limiting 2-hour period, at the Low Population Zone (LPZ) outer boundary for the duration of the accident, and in the CR for 30 days.

The dose consequence analyses were performed by the licensee using the RADTRAD-Numerical Applications, Inc. (NAI) computer code. RADTRAD-NAI estimates the radiological doses at offsite locations and in the CR of nuclear power plants as a consequence of postulated accidents. The code considers the timing, physical form and chemical species of the radioactive material released into the environment.

RADTRAD-NAI was developed from the "RADTRAD: Simplified Model for RADionuclide Transport and Removal And Dose Estimation," computer code. The NRC sponsored the development of the RADTRAD radiological consequence computer code, as described in NUREG/CR-6604.[174] The RADTRAD code was developed by Sandia National Laboratories for the NRC. The code estimates transport and removal of radionuclides and radiological consequence doses at selected receptors. The NRC staff uses the RADTRAD computer code to perform independent confirmatory dose evaluations as necessary to ensure a thorough understanding of the licensee's methods. The results of the evaluations performed by the licensee, as well as the applicable dose guidelines from RG 1.183, are shown in Table 1 of this SE.

The licensee used the ORIGEN computer code to generate the core radionuclide inventory for use in determining source term releases. The inventory, consisting of 72 isotopes at end of fuel cycle curie levels, formed the input for the RADTRAD-NAI dose evaluation code. The licensee used committed effective dose equivalent (CEDE) and effective dose equivalent (EDE) dose conversion factors (DCFs) from Federal Guidance Reports (FGR) 11 and 12, as is appropriate

[173] Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors," July 2000. (ADAMS Accession No. ML003716792)
[174] NUREG/CR-6604, "RADTRAD: A Simplified Model for Radionuclide Transport and Removal and Dose Estimation," 1998

for an AST evaluation. The use of ORIGEN and DCFs from FGR 11 and FGR 12 is in accordance with RG 1.183 guidance and is acceptable to the NRC staff.

2.9.2.1 Loss-of-Coolant Accident

The radiological consequence design basis LOCA analysis is a deterministic evaluation based on the assumption of a major rupture of the primary RCS piping. The accident scenario assumes the deterministic failure of the ECCS to provide adequate core cooling which results in a significant amount of core damage, as specified in RG 1.183. This general scenario does not represent any specific accident sequence, but is representative of a class of severe damage incidents that were evaluated in the development of the RG 1.183 source term characteristics. Such a scenario would be expected to require multiple failures of systems and equipment and lies beyond the severity of incidents evaluated for design basis transient analyses.

Amendment No. 233, dated September 20, 2006,[175] regarding recirculation spray system parameters, represents the MPS3 CLB for the LOCA. In the evaluation of the LOCA design basis radiological analysis, the licensee included dose contributions from the following sources:

(1) Containment leakage;

(2) ECCS component leakage;

(3) RWST vent releases;

(4) Shine from containment; and

(5) Shine from the CR filter loading.

During a design-basis LOCA, it is assumed that the initial fission product release to the containment will last 30 seconds and will consist of the radioactive materials dissolved or suspended in the RCS liquid. After 30 seconds, fuel damage is assumed to begin and is characterized by clad damage that releases the fission products in the fuel gap. The fuel gap release phase is assumed to continue until 30 minutes after the initial breach of the RCS. As core damage continues, the gap release phase ends and the early in-vessel release phase begins. The early in-vessel release phase continues for the next 1.3 hours. The licensee used the LOCA source term release fractions, timing characteristics, and radionuclide grouping as specified in RG 1.183 for evaluation of the LOCA.

Containment Sprays

The MPS3 design-basis LOCA analysis credits the use of containment sprays to remove elemental and particulate iodine from the containment atmosphere. Credit for the use of containment sprays for elemental and particulate iodine removal by the QSS was approved in Amendment No. 211, dated September 16, 2002,[176] and November 25, 2002.[177] In Amendment No. 211, the NRC staff approved a QSS coverage value of 50.27 percent and a QSS effective

[175] ADAMS Accession No. ML062220160
[176] ADAMS Accession No. ML022470399
[177] ADAMS Accession No. ML023290568

initiation time of 70.2 seconds. The CLB analysis, as approved in Amendment No. 233, assumes that the percentage of containment that is covered by the QSS is 49.63 percent and that the QSS becomes effective at 71 seconds post-LOCA.

The SPU analysis maintains the CLB assumption that the percentage of containment covered by the QSS is 49.63 percent. For the SPU analysis, the licensee performed a new containment analysis that determined various operation times for the QSS. The licensee chose values for QSS operation that, when used in conjunction with the operation of the RSS, resulted in the most conservative doses. As a result of this analysis, the licensee revised the time at which the QSS becomes effective from 71 to 80 seconds post-LOCA. The licensee also revised the end time for effective QSS operation from 6,620 seconds to 10,000 seconds.

The CLB analysis credits the RSS for containment iodine removal at 2710 seconds post-LOCA, thereby increasing the sprayed coverage to 64.5 percent during the time when both spray systems are operating. For conservatism, the licensee maintained the partitioning of the fission products source between the sprayed/unsprayed regions consistent with the percentage of containment with the percentage of containment sprayed/unsprayed during thess periods. The CLB mixing rate during spray operation is assumed to be two turnovers of the unsprayed volume per hour, which is consistent with the value accepted by the NRC staff in Amendments No. 211 and No. 233. The assumed mixing rate during spray operation for the SPU analysis remains consistent with the CLB assumption of two turnovers of the unsprayed volume per hour.

The SPU analysis maintains the CLB assumption that the percentage of containment that is covered during the period when both spray systems are operating is 64.5 percent. For the SPU analysis the licensee performed a new containment analysis that determined various operation times for the RSS. The licensee chose values for RSS operation that, when used in conjunction with QSS operation, resulted in the most conservative doses. As a result of this analysis, the licensee revised the time at which the RSS becomes effective from 2710 to 5500 seconds post-LOCA. The licensee maintained the CLB end time for the effectiveness of the RSS as the 30 day end of the analysis period.

The containment spray volumes for the QSS, RSS and the combined QSS plus RSS periods of operations, based on conservative evaluations of the total containment spray volume and the coverage fractions, remain the same as the CLB values that were accepted by the NRC staff in Amendment No. 233.[178]

The SPU analysis maintains the CLB credit for removal of elemental iodine due to sprays until the decontamination factor (DF) reaches a value of 200. For the time period during which sprays are assumed to be operating, the licensee calculated an elemental iodine DF of 10 for use in the SPU analysis. The licensee used SRP 6.5.2 together with conservative input values, to calculate values for elemental iodine removal coefficients that ranged from a low of 14 per hour to a high of 66 per hour depending on assumptions for QSS/RSS operation. The licensee chose an elemental iodine removal coefficient value of 10 per hour for conservatism. This value represents a lower more conservative value than the CLB elemental iodine removal coefficient value of 20 per hour.

[178] ADAMS Accession No. ML062220160

The licensee chose a lower, more conservative value for the QSS flow rate of 28,846 ft^3 per hour based on the containment pressure reanalysis associated with the SPU. QSS flow rate results in a lower, more conservative QSS particulate iodine removal coefficient of 11.5 per hour as opposed to the CLB value of 12.37 per hour.

The licensee chose a lower, more conservative value for the RSS flow rate of 17,308 ft^3 per hour based on the containment pressure reanalysis associated with the SPU. The lower RSS flow rate results in a lower, more conservative combined QSS and RSS particulate iodine removal coefficient of 13.57 per hour as opposed to the CLB value of 14.11 per hour.

In the CLB analysis, the licensee calculated that a particulate iodine DF of 50 would be attained at 2.045 hours, at which time the calculated particulate removal rate was reduced by a factor of 10, in accordance with SRP 6.5.2 and RG 1.183. For the SPU analysis, the lower calculated removal coefficients for particulate iodine resulted in a slightly later time of 2.063 hours to reach a DF of 50.

During the period following the effective QSS operation, the lower, more conservative value for the RSS flow rate results in a lower, more conservative RSS particulate iodine removal coefficient of 0.65 per hour as opposed to the CLB value of 0.78 per hour after a DF of 50 is reached. Consistent with the CLB, credit for the particulate iodine removal due to sprays in the SPU analysis is taken for as long as the RSS remains operating.

The NRC staff reviewed the changes made to the CLB assumptions for the evaluation of spray removal credit in the SPU LOCA analysis and found that the changes were conservative and, therefore, acceptable.

Natural Deposition in Unsprayed Region of Containment

In the CLB LOCA analysis, the licensee credited a reduction in airborne radioactivity in the unsprayed region of the containment by natural deposition. The licensee used the Powers model as incorporated into the RADTRAD computer code. The licensee conservatively credited aerosol deposition using the Powers model set at the 10th percentile for the unsprayed region of the containment. This approach is acceptable to the NRC staff because it does not double count iodine removal in the containment by limiting credit for natural removal to the unsprayed regions only. The licensee did not change any assumptions regarding the credit for a reduction in airborne radioactivity in the unsprayed region of the containment by natural deposition in the SPU LOCA analysis.

Secondary Containment Bypass Release Pathways

The CLB LOCA analysis includes assumptions describing the plant-specific issue of unfiltered post-LOCA releases due to damper bypass and duct leakage from the plant ventilation system that was described and approved in Amendment No. 211 (previously referenced). Amendment No. 211 identified potential release pathways from the secondary containment to the environment that could bypass the supplementary leakage collection and release system (SLCRS) filter following a DBA due to non-nuclear safety (NNS) grade exhaust fan operation after the accident. Amendment No. 211 also approved an operator action that would manually trip the breakers on selected NNS grade exhaust fans at 1 hour and 20 minutes post-LOCA. This operator action is only credited in the LOCA CR habitability analysis. In the CLB analysis,

the licensee did not change the licensing basis for the post-accident operation of the SLCRS as described and approved in Amendment No. 211 and, therefore, the assumptions related its operation remained acceptable to the NRC staff in the CLB LOCA as approved in Amendment No. 233.

For the SPU analysis the licensee made several conservative changes to the plant-specific issue of unfiltered post-LOCA releases due to damper bypass and duct leakage from the plant ventilation system. These changes include:

(1) The operator action to manually trip the breakers on selected fans for the CR analysis is no longer credited. All fans are assumed to continue to operate consistent with the CLB off-site analysis.

(2) All filtered releases are assumed to be discharged from the turbine building ventilation vent. This release pathway has larger, more conservative atmospheric dispersion factors (χ/Qs) than the MPS3 stack release pathway.

(3) The unfiltered releases from the auxiliary building are also assumed to be discharged from the turbine building ventilation vent with the more conservative χ/Qs.

(4) The auxiliary building is assumed to be homogeneously mixed. Therefore, the auxiliary building is treated as one compartment with all releases into and out of each elevation combined with the assumptions listed above.

The licensee calculated a larger CR dose due to the changes shown, and although the EAB and LPZ doses decreased slightly due to the new source term, these changes are shown to be conservative. In addition these changes also simplify the licensee's analysis by significantly reducing the required number of separate RADTRAD models for each offsite and CR LOCA dose analysis. The NRC staff reviewed the changes made to the plant-specific issue of unfiltered post-LOCA releases due to damper bypass and duct leakage from the plant ventilation system and finds the changes to be conservative and, therefore, acceptable.

Containment Leakage

The total containment leakage (L_a), for MPS3 consists of both filtered and bypass leakage and, as governed by TS, is 0.3 weight percent per day. The entire containment leak rate bypasses the secondary containment until the SLCRS drawdown is effective at 2 minutes post-LOCA. After SLCRS drawdown, the bypass leak rate is assumed to be reduced by a factor of 0.06 to 0.018 weight percent per day. The licensee assumes this bypass leak rate is released unfiltered at ground level directly from containment. The containment leak rate, $L_{a,}$ is reduced by one-half at 24 hours for offsite calculations, and at 1 hour for CR dose calculations. This assumption, of a reduction in the containment leak rate by 50 percent after 1 hour for the CR habitability analysis, was used in calculations supporting Amendment No. 59,[179] which eliminated the post-LOCA negative containment pressure requirement. This assumption was also referenced in the description of calculations provided as supplemental information supporting Amendment No. 211, which changed the licensing basis for the post-accident operation of the SLCRS. The assumption of a 50 percent reduction in containment leakage

[179] ADAMS Accession No. ML011790140

after 1 hour is based on the fact that the MPS3 post-LOCA containment pressure is rapidly reduced compared to typical pressurized water reactors because the MPS3 containment was originally designed to be operated at sub-atmospheric pressure.

The preceding discussion of the assumptions used to evaluate containment leakage, describe the CLB as well as the SPU analysis since the licensee did not make any changes to these assumptions for the SPU LOCA analysis.

ECCS Leakage

During a LOCA, a portion of the fission products released from the fuel will be carried to the containment sump via spillage from the RCS, by transport of activity from the containment atmosphere to the sump by containment sprays, and by natural processes such as deposition and plateout. During the initial phases of a LOCA, safety injection and the containment spray systems draw water from the RWST. Several minutes after accident initiation, valve realignment occurs to switch the suction water source for the ECCS from the RWST to the containment sump. This recirculation flow causes contaminated water to be circulated through piping and components outside of the containment, where small amounts of system leakage could provide a path for the release of fission products to the environment.

To evaluate the radiological consequences of ECCS leakage, the licensee used the deterministic approach as prescribed in RG 1.183. This approach assumes that, except for the noble gases, all of the fission products released from the fuel mix instantaneously and homogeneously in the containment sump water. Except for iodine, all of the radioactive materials in the sump are assumed to be in particulate form and, therefore, are retained in the liquid phase. As a result, the licensee assumed that the fission product inventory available for release from ECCS leakage consists of 40 percent of the core inventory of iodine. This amount is the combination of the 5 percent released to the sump water during the gap release phase and the 35 percent released to the sump water during the early in-vessel release phase. This source term assumption is conservative in that 100 percent of the radioiodines released from the fuel are assumed to reside in both the containment atmosphere and in the containment sump.

ECCS leakage develops when ESF systems circulate sump water OC and leaks develop through packing glands, pump shaft seals and flanged connections. The licensee controls the quantity of ECCS leakage through TS 6.8.4a, “Primary Coolant Sources Outside Containment Program Manual,” which calculates the maximum allowable leakage as 4,780 cubic centimeters per hour (cc/hr). RG 1.183 states that the magnitude of the ECCS leakage should be taken as two times the sum of the simultaneous leakage from all components in the ESF recirculation systems, above which the TS, or licensee commitments, would require declaring such systems inoperable. Accordingly, the licensee used a value of 10,000 cc/hr to assess the ECCS leakage contribution to the LOCA dose.

The licensee assumed that the leakage of recirculating sump fluids commences at 2,500 seconds, which is the earliest time that the recirculation of contaminated fluids would begin. The licensee conservatively rounded down the CLB value of 2,530 seconds for the SPU analysis. The licensee calculated a flashing fraction which corresponds to an assumed maximum containment sump temperature of 230 °F at the start of sump recirculation. However, in following the guidance of RG 1.183, the licensee conservatively used a significantly higher

flashing fraction of 0.1 for the ECCS leakage calculation for the duration of the event. As a result, 10 percent of the entrained iodine activity in the ECCS leakage effluent is assumed to be released to the atmosphere of the surrounding auxiliary building. In accordance with RG 1.183, the licensee assumed that the chemical form of the released iodine is 97 percent elemental and 3 percent organic.

Releases from the RWST due to ECCS Back Leakage

Following a design-basis LOCA, valve realignment occurs to switch the suction water source for the ECCS from the RWST to the containment sump. In this configuration, MOVs and check valves in the normal suction line from the RWST, and MOVs in the recirculation line, provide isolation between this contaminated recirculation flow stream and the RWST. Although the RWST is isolated during recirculation, design leakage through ECCS valving provides a pathway for back leakage of the containment sump water to the RWST. The RWST is located in the plant yard and is vented to the atmosphere. The licensee used RADTRAD-NAI to model leakage of ECCS fluid through these valves back into the RWST, with the subsequent release of the evolved iodine to the environment, through the vent at the top of the RWST.

The licensee followed the guidance of RG 1.183 by assuming that the source term for releases from this pathway consists only of iodine, with 97 percent assumed to be in the elemental form and the remaining 3 percent in organic form. The licensee provided a detailed evaluation of the potential leakage pathways from recirculating fluid systems back to the RWST. The licensee used the methodology approved in Amendment No. 176[180] to calculate times, flow rates, and volumes for each identified pathway.

Using the methodology approved in Amendment No. 176, the licensee based the time for contaminated sump water to reach the RWST on the calculated flow rates and the volume of clean water in the associated piping prior to the initiation of the recirculation phase of ECCS operation. The time required to displace the volume of clean water was reduced by 50 percent to account for mixing in the lines. The licensee considered this to be a reasonable assumption and stated that since the sump fluid is relatively cool, thermal mixing will be minimal. In addition, the licensee stated that the assumption also considered that the lines are isolated and stagnant except for minor leakage and that the mixing due to flow is negligible.

The licensee calculated an RWST vent airflow rate using the ideal gas law. The expected RWST volumetric changes were determined based on conservative estimates of the rise in air temperature within the RWST due to solar heating. The licensee performed a detailed analysis to determine the partition coefficient (PC) applicable to the iodines in the RWST water. The licensee calculated a DF of 330 for the release of iodines from the RWST as a result of back leakage. However, for conservatism, the licensee used a DF of 100 for the evaluation of the dose contribution from RWST back leakage.

The licensee used CLB assumptions for the RWST maximum fill volume, the times and integrated flow rates for RWST backleakage, and the RWST breathing rate in the SPU LOCA analysis.

[180] ADAMS Accession No.ML993220168

The licensee modified the RWST air holdup volume and stated that the CLB value is based on a minimum water volume of 6.37E+03 ft^3. The breathing rate of the RWST should be based on the air volume in the RWST at the minimum water level after injection. The CLB RADTRAD-NAI model used the water volume instead of the air volume causing an inconsistency between the tank volume and the derived breathing rate. The licensee modified the analysis and used the RWST air volume of 1.549E+05 ft^3 in the SPU LOCA analysis.

The quantity of grams of iodine in the core at the EOC was increased from the CLB value of 20,000 to the SPU value of 26,000 due to the higher power level in the SPU analysis. The maximum concentration of iodines in the RWST as a result of backleakage was increased from the CLB value of 1.2 milligrams per liter to 1.5 milligrams per liter due to the higher power level in the SPU analysis.

Conclusion

The licensee evaluated the radiological consequences resulting from the postulated LOCA for the SPU conditions and concluded that the radiological consequences at the EAB, LPZ, and CR are within the reference values provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP 15.0.1. The NRC staff's review finds that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.1 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 5, and the licensee's calculated dose results are given in Table 1. The NRC staff performed independent confirmatory dose evaluations, as necessary, to ensure a thorough understanding of the licensee's methods. The NRC staff finds that the EAB, LPZ, and CR doses estimated by the licensee for the LOCA meet the applicable accident dose guidelines and are, therefore, acceptable.

2.9.2.2 Fuel Handling Accident

This accident analysis postulates that a spent fuel assembly is dropped during fuel handling and strikes an adjacent assembly during the fall. All of the fuel rods in the dropped assembly and 19 fuel rods in the struck assembly are conservatively assumed to experience fuel cladding damage, releasing the radionuclides within the fuel rod gap to the fuel pool or reactor cavity water. The affected assemblies are assumed to be those with the highest inventory of fission products of the 193 assemblies in the core. Volatile constituents of the core fission product inventory migrate from the fuel pellets to the gap between the pellets and the fuel rod clad during normal power operations. The fission product inventory in the fuel rod gap of the damaged fuel rods is assumed to be instantaneously released to the surrounding water as a result of the accident. Fission products released from the damaged fuel are decontaminated by passage through the overlaying water in the reactor cavity or SFP, depending on their physical and chemical form.

The licensee assumed no decontamination for noble gases, a DF of 200 for radioiodines, and retention of all particulate fission products. As prescribed in RG 1.183, the FHA is analyzed based on the assumption that 100 percent of the fission products released from the reactor cavity or SFP are released to the environment in 2 hours. The licensee did not credit filtration, holdup, or dilution of the released activity. Since the assumptions and inputs are identical for the FHA within containment and the FHA OC, the results of the two events are identical.

The CLB assumptions pertaining to the source term for the FHA have been changed as a result of the SPU analysis. The licensee states that MPS3 SPU reload cores will contain fuel rods that do not meet the criteria of RG 1.183, Table 3, footnote 11, which states in part that:

> The release fractions listed here [Table 3] have been determined to be acceptable for use with currently approved [light-water reactor] LWR fuel with a peak burnup up to 62,000 [megawatt days per metric-ton uranium] MWD/MTU provided that the maximum linear heat generation rate does not exceed 6.3 [kilowatt per foot] kw/ft peak rod average power for burnups exceeding 54 [gigawatt-days per metric ton uranium] GWD/MTU. As an alternative, fission gas release calculations performed using NRC approved methodologies may be considered on a case-by-case basis. To be acceptable, these calculations must use a projected power history that will bound the limiting projected plant-specific power history for the specific fuel load.

Therefore, the licensee re-analyzed the FHA assuming a higher fission product inventory in the gap. The gap fractions applied by the licensee were modified from those listed in RG 1.183, Table 3 because the Table 3, footnote 11 criteria are exceeded for the MPS3 reload cores. The new bounding FHA analysis conservatively assumes 67 percent of the rods in a fuel assembly exceed the guidance of footnote 11. The licensee used the gap fractions listed in RG 1.25[181] as modified by the direction of NUREG/CR-5009 for the fraction of rods in a fuel assembly that are assumed to exceed the guidance in footnote 11. The remaining 33 percent of the rods that meet the guidance of footnote 11 use the gap fractions from RG 1.183, Table 3. The determination of the activity released from the limiting fuel assembly is based on the combination of these gap fractions.

For the FHA, the licensee assumes that it will take 10 seconds for the CR to isolate following detection of released activity by the MPS3 CR air inlet detectors. In an isolated or neutral pressure condition, the licensee assumes an unfiltered inleakage of 350 cubic feet per minute (cfm). This assumption provides a considerable margin above measured test results, which indicate unfiltered inleakage for the neutral condition of less than 100 cfm. The licensee does not credit the operation of the CR envelope pressurization system (CREPS) in any of the DBA dose analyses and has removed the associated TS for this system. However, the licensee did not physically remove the CREPS and, therefore, in the time sequence of the FHA analysis, the licensee has allotted time for the operation of the CREPS without crediting CR pressurization or its inleakage reducing benefit.

For the FHA, the licensee assumes that the CR will experience 10 seconds of normal ventilation intake flow at 1,595 cfm prior to CR isolation. After CR isolation, the licensee assumes a period of 101 minutes with an assumed unfiltered inleakage at 350 cfm. The 101 minute period assumes a neutral pressure condition that does not credit the activation of the pressurization portion of the safety-related CREVS. The operation of the CREVS is ensured by TS 3.7.6. The 101 minute period includes 1 minute for CREPS actuation, 60 minutes for CREPS operation, and 40 minutes for the manual alignment of the CREVS. This assumption is very conservative in that it assumes an unfiltered inleakage of 350 cfm persists for a 61 minute time period allotted for CREPS operation, in addition to the 40 minutes allotted for the manual alignment of the

[181] Regulatory Guide 1.25, "Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling and Storage Facility for Boiling and Pressurized Water Reactors", dated March, 1972.

CREVS. During the 61 minute time period allotted for CREPS operation, there is no credit taken for its inleakage reduction benefit. At 1.685 hours post-LOCA (101 minutes, 10 seconds), the licensee assumes that the pressurization portion of the CREVS is actuated providing a filtered intake flow of 230 cfm. The unfiltered inleakage is assumed to be reduced to 100 cfm due to the operation of the CREVS.

Due to the increased gap inventory caused by exceeding the guidelines in of RG 1.183, footnote 11, the licensee researched the accident analysis parameters in order to gain margin in the SPU FHA CR dose analysis. The licensee changed the assumed CREVS 666 cfm filtered recirculation flow initiation time from the CLB time of 1.685 hours, to 30 minutes in order to provide the margin necessary to meet the CR dose limits for the FHA. The licensee will implement a plant design change and procedure modifications to support this change to the CLB recirculation filter initiation time. In a letter dated January 10, 2008, the licensee provided the following additional information describing the modifications to support the change to the CLB recirculation filter initiation time for the SPU FHA.

The licensee states that the SPU FHA analysis requires that the CREVS be operating in the filtered recirculation MODE within 30 minutes from receipt of a high radiation CBI signal. The licensee considered the possibility of crediting manual operator action to accomplish this, but decided to modify the control building ventilation system and the CREVS to perform this action automatically. The licensee will modify the CREVS to start in the pressurized filtration MODE automatically, providing both pressurized filtration and filtered recirculation, upon receipt of a CBI signal. The following modifications will be made:

(1) The control building inlet dampers will be changed from their present MODE of operation; normally open, fail closed, close on CBI, to normally open, fail open, open on CBI.

(2) The CREVS will be modified to receive a signal to automatically start upon receipt of a CBI signal and the associated dampers will align to the pressurized filtration MODE of operation.

(3) The CBI signal to actuate the air bottle outlet control valves for the CREPS will be removed. The CREPS has been removed from the MPS3 TS by Amendment No. 232, which approved the AST for MPS3.[182] The CREPS is not credited in any accident analysis. With this modification, the CREPS can be maintained, with manual actuation from the CR, in either a pressurized or depressurized condition as plant operations dictate.

(4) Various plant process computer inputs and Control Board status lights will be modified to reflect the changed operating modes and control signals described above.

The automatic initiation of the CREVS upon receipt of a CBI signal provides additional margin to the FHA CR dose consequence analysis. The FHA CR analysis credits filtered recirculation after 30 minutes and filtered pressurization after 1.685 hours. With the implementation of the described changes, both filtered recirculation and filtered pressurization will be initiated upon

[182] ADAMS Accession No. ML061990135

receipt of a CBI signal. In addition, the changes to the CR ventilation system and the CREVS will provide additional margin to the remainder of the SPU dose consequence analyses since they do not credit automatic initiation of the CREVS.

FHA Involving the Drop of a Non-Fuel Assembly

The licensee performed a new analysis of an FHA involving the drop of a non-fuel assembly component into the SFP to demonstrate that operation of the CREVS is not necessary while conducting these types of activities in the SFP. The licensee's analysis includes doses associated with the release of gap activity from a stored fuel assembly inside the fuel building. Doses were calculated in the MPS3 CR. The licensee performed the analysis using the same methodology that was used to evaluate the CR and offsite doses resulting from the FHA. The new analysis maintains consistency with RG 1.183 and uses TEDE radiological units and dose guidelines, CLB onsite χ/Q values, and FGR No. 11 and 12 DCFs.

As a result of the new analysis, the requirements to maintain the OPERABILITY of the Control Room Emergency Air Filtration Systems in Modes 5 and 6 are no longer necessary. Thus, the licensee proposed to remove the applicability of Modes 5 and 6 for the Control Room Emergency Air Filtration Systems from TS 3/4.7.7.

The licensee's mechanical analysis determined the potential for fuel damage to stored fuel assemblies resulting from the drop of non-fuel components, such as an RCCA, a neutron source or a thimble plug. The licensee states that for these components, the drop height is limited to 2.7 feet. The licensee's results show no fuel damage for all fuel types with the exception of the original core loading of 17 by 17 standard fuel. For this fuel type, used only in the first three cycles of operation, a corrosion mechanism has been identified that reduces the structural capability of the assembly. The licensee's calculation determines that for the drop of an RCCA together with an RCCA handling tool, the maximum fuel damage is 18 rods. For conservatism, the licensee performed a bounding radiological analysis that assumed 30 rods were damaged as a result of a drop of a non-fuel assembly such as an RCCA together with an RCCA handling tool.

The licensee's radiological analysis used the same assumptions and inputs as for the FHA involving a drop of a spent fuel assembly, except for the assumed amount of fuel damage and the availability of the CREVS. The licensee did not credit CR isolation or operation of the CREVS to show compliance with the reference values specified in 10 CFR 50.67 and the accident-specific dose guidelines in RG 1.183. The licensee did not provide the calculated offsite doses for this event since they are clearly bounded by the FHA described in Section 2.9.2.2.2 due to the significantly larger extent of the assumed fuel damage. The FHA described in Section 2.9.2.2.2 assumes that a total of 283 rods experience fuel clad damage whereas the FHA involving the drop of a non-fuel assembly assumes that 30 rods experience fuel clad damage.

The staff reviewed the licensee's analysis and concludes that it is acceptable to delete Modes 5 and 6 from TS 3/4.7.7.

Conclusion

The licensee evaluated the radiological consequences resulting from the postulated FHA for SPU conditions and concluded that the radiological consequences at the EAB, LPZ, and CR are within the referenced values provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP 15.0.1. The NRC staff's review finds that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.1 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 6, and the licensee's calculated dose results are given in Table 1. The NRC staff performed independent confirmatory dose evaluations, as necessary, to ensure a thorough understanding of the licensee's methods. The NRC staff finds that the EAB, LPZ, and CR doses estimated by the licensee for the FHA meet the applicable accident dose guidelines and are, therefore, acceptable.

2.9.2.3 Steam Generator Tube Rupture Accident

In the SGTR accident, it is assumed that there is a complete severance of a single SG tube. The accident is assumed to take place at full power with the reactor coolant contaminated with fission products corresponding to continuous operation with a limited amount of fuel damage. The postulated break allows primary coolant liquid to leak to the secondary side of the ruptured SG, also referred to as the affected SG, with an assumed release to the environment through the SG atmospheric dump valves (ADVs). For this accident scenario, a LOOP is assumed to occur concurrently with the tube rupture.

Within the first few minutes of the accident, the CR isolates, the reactor trips, and SI is actuated. Because the LOOP renders the MC unavailable, the plant is cooled down by releasing steam to the environment. In the licensee's analysis, the ADV on the affected SG is assumed to open to control SG pressure at the beginning of the event. After operator action is credited to close the affected SG ADV, the same ADV is assumed to fail fully open. The affected SG discharges steam to the environment for 2,702 seconds (0.7506 hours) until the generator is manually isolated a second time by closure of the SG atmospheric dump block valve (ADBV). Break flow into the affected SG continues until 6412 seconds (1.781 hours), at which time the RCS is at a lower pressure than the secondary system. A portion of the break flow will flash to steam until 3381 seconds (0.9392 hours). Additional releases from the affected SG are modeled from 2 to 11 hours to complete depressurization of the SG early in the event, which maximizes the dose consequences. Depressurization of the SG is necessary to allow for RHR system (RHRS) cooling.

The licensee modeled the three unaffected SGs as one volume, which is referred to in the analysis as the unaffected SG. The licensee evaluated the dose consequences from discharges of steam from the unaffected SG for a period of 35.75 hours. The 35.75 hour time period includes 24 hours for the primary system to cool sufficiently to allow an alignment to the RHRS, an additional 11.75 hours of steaming required to reduce the system heat load to the point where RHRScan remove all the decayheat using onlysafety grade equipment, and the impact of the assumption of a concurrent LOOP. After a period of 35.75 hours, the RHRS is capable of removing 100 percent of the decay heat. At this point in the accident sequence, steaming is no longer required for cool down and releases from the unaffected SGs are terminated.

Appendix F of RG 1.183 identifies acceptable radiological analysis assumptions for an SGTR accident. If a licensee demonstrates that no or minimal fuel damage is postulated for the limiting event, the activity released should be the maximum coolant activity allowed by TS. Two radioiodine spiking cases are considered. The first case is referred to as a pre-accident iodine spike, and assumes that a reactor transient has occurred prior to the postulated SGTR that has raised the primary coolant iodine concentration to the maximum value permitted by the TS for a spiking condition. For MPS3, the maximum iodine concentration allowed by TS as a result of an iodine spike is 60 micro curies per gram (μCi/gm) dose equivalent iodine 131 (DEI).

The second case assumes that the primary system transient associated with the SGTR causes an iodine spike in the primary system. This case is referred to as a concurrent iodine spike. The increase in primary coolant iodine concentration for the concurrent iodine spike case is estimated using a spiking model that assumes that the iodine release rate from the fuel rods to the primary coolant increases to a value 335 times greater than the release rate corresponding to the iodine concentration at the TS limit for normal operation. For MPS3, the RCS TS limit for normal operation is 1 μCi/gm DEI.

The licensee's evaluation indicates that no fuel damage is predicted as a result of an SGTR accident. Therefore, consistent with the current licensing analysis basis and regulatory guidance, the licensee performed the SGTR accident analyses for the pre-accident iodine spike case and the concurrent accident iodine spike case.

Releases from the Affected SG

The licensee assumed that the source term resulting from the radionuclides in the primary system coolant, including the contribution from iodine spiking, is transported to the affected SG by the break flow. In the licensee's analysis for MPS3, break flow is terminated after 1.781 hours. A portion of the break flow is assumed to flash to steam because of the higher enthalpy in the RCS. The licensee did not take credit for scrubbing of the flashed break flow by the liquid in the SG. In the licensee's analysis for MPS3, break flow flashing is terminated after 0.9392 hours. The noble gas and iodine in the flashed portion of the break flow will ascend to the steam space of the affected generator and be available for release with no credit taken for scrubbing by the SG liquid. The radionuclides entering the steam space as the result of flashing pass directly to the environment through the SG ADVs. The licensee credited holdup of noble gases in the affected SG due to manual operator action to close the ADBV at 0.7506 hours with the break flow continuing to enter the generator until 1.781 hours. Therefore, in the licensee's analysis, noble gases are held up in the affected generator from 0.7506 hours to 2 hours. Subsequently, during depressurization of the affected SG, the accumulated contents are released from 2 to 11 hours post-accident.

The iodine and other non-noble gas isotopes in the non-flashed portion of the break flow are assumed to mix uniformly with the SG liquid mass and be released to the environment in direct proportion to the steaming rate and in inverse proportion to the applicable PC. In accordance with the guidance from RG 1.183, the licensee's evaluation of the releases from the steaming of the liquid mass in the SG credits a PC of 100 for all non-noble gas isotopes. Following the applicable regulatory guidance, the licensee assumed that all noble gas radionuclides released from the primary system are released to the environment without reduction or mitigation.

Releases from the unaffected SGs

The licensee assumed that the source term resulting from the radionuclides in the primary system coolant, including the contribution from iodine spiking, is transported to the unaffected SGs at a rate of 1 gallon per minute (gpm), which exceeds the leak-rate LCO of 150 gallons per day (gpd) per SG, as specified in the TS. All radionuclides in the primary coolant leaking into the unaffected SGs are assumed to enter the SG liquid. Radionuclides initially in the SG liquid, and those entering the SG liquid from the leakage flow, are released as a result of secondary liquid steaming, with a PC of 100 for all non-noble gas isotopes. Therefore, 1 percent of the iodines and particulates are assumed to pass into the steam space and then directly to the environment. The licensee assumed that all noble gases that are released from the primary system to the unaffected SG are released to the environment without reduction or mitigation. Releases were assumed to continue from the unaffected SG for a period of 35.75 hours, until the primary system cools to below 350 °F and the RHRS is able to remove 100 percent of decay heat with no requirement for steaming to augment cooldown. The 35.75 hour steaming period is based on the time necessary to cooldown crediting safety grade equipment only. The 35.75 hour steaming period includes the conservative assumption that the time to achieve the RHRS entry condition of RCS temperature at 350 °F was delayed until 24 hours post-accident. The 35.75 hour steaming period includes an additional 11.75 hours of steaming required to reduce the system heat load to the point where the RHRS can remove all the decay heat using only safety grade equipment.

The licensee used the RADTRAD-NAI computer code to model the time dependent transport of radionuclides, from the primary to secondary side and consequently to the environment via the ADVs. The licensee's analysis follows the guidelines of RG 1.183, Appendix F, which identifies acceptable radiological analysis assumptions for the SGTR. The licensee assumed the CR ventilation timing sequence indicated in Table 7, which does not credit automatic initiation of the CREVS.

Conclusion

The licensee evaluated the radiological consequences resulting from the postulated SGTR for SPU conditions and concluded that the radiological consequences at the EAB, LPZ, and CR are within the reference values provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP 15.0.1. The NRC staff's review finds that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.3 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 7, and the licensee's calculated dose results are given in Table 1. The NRC staff performed independent confirmatory dose evaluations, as necessary, to ensure a thorough understanding of the licensee's methods. The NRC staff finds that the EAB, LPZ, and CR doses estimated by the licensee for the SGTR meet the applicable accident dose guidelines and are, therefore, acceptable.

2.9.2.4 Main Steam Line Break Accident

The MSLB accident considered is the complete severance of the largest main steam line OC. The licensee's evaluation indicates that no fuel damage is predicted as a result of an MSLB accident. Therefore, consistent with the current licensing analysis basis and RG 1.183, the licensee performed the MSLB accident analyses assuming that the accident occurs with both

the primary and secondary coolant concentrations at their TS limit for operation. As in the SGTR accident, the licensee's MSLB evaluation includes the effects of primary system iodine spiking for both the pre-accident iodine spike case and the concurrent iodine spike case. The spiking cases are as described for the SGTR with the following exception. For the MSLB accident, the concurrent iodine spike is estimated using a spiking model that assumes that the iodine release rate from the fuel rods to the primary coolant increases to a value 500 times greater than the release rate corresponding to the iodine concentration at the TS limit for normal operation. In effect, it is assumed that the MSLB accident results in a more severe concurrent iodine spike than the SGTR accident. The duration of the concurrent iodine spike is assumed to be 8 hours, in accordance with the applicable guidance.

The MSLB accident begins with a break in one of the main steam lines leading from a SG to the turbine. The SG that experiences a secondary side depressurization as a result of an MSLB is referred to as being in a faulted condition. The licensee uses the term affected SG to describe the faulted SG. In order to maximize the CR dose, the licensee assumed that the steam line break occurs in the turbine building. The affected SG is assumed to release steam for 65.75 hours, which is the time required for the RCS to be cooled down to 200 °F. The 65.75 hour steaming period is based on the time necessary to cooldown, crediting safety grade equipment only. The licensee has conservatively determined that dry out of the affected SG will occur 16.5 seconds after the MSLB.

The licensee evaluated the accident assuming a concurrent LOOP. Due to the assumption of a LOOP, the condenser is unavailable and cool down of the primary system is accomplished through the release of steam from the unaffected SGs. The release from the unaffected SGs continues for 36.25 hours through the ADVs until the RHRS can fully remove decay heat.

The licensee assumed that the source term resulting from the radionuclides in the primary system coolant and from the iodine spiking in the primary system, is transported to the SGs at a rate of 1 gpm, which exceeds the leak-rate LCO of 150 gpd per SG, as specified in the TS. The maximum amount of primary-to-secondary leakage allowed by the TS to any one SG is 500 gpd. The licensee conservatively assigned this leak rate of 500 gpd, or 0.35 gpm, to the affected SG to maximize the calculated dose consequence.

For the affected SG, the licensee assumed the release passes directly into the turbine building with no credit taken for holdup, partitioning or scrubbing by the SG liquid. The licensee did not take credit for any holdup or dilution in the turbine building. The licensee's analysis assumes the release into the turbine building is exhausted to the environment and subsequently transported from the environment into the CR assuming conservative χ/Qs.

The licensee assumed that during the first 16.5 seconds of the accident, the affected SG steams dry as a result of the MSLB, releasing all of the nuclides in the secondary coolant that were initially contained in the SG. The near instantaneous release of the secondary coolant from the affected SG represents a significant contribution to the total dose, since the inventory is conservatively evaluated at the secondary side TS limit of 0.1 µCi/gm DEI. The licensee conservatively assumed that during the first 65.75 hours, primary coolant leaks into the affected SG at the rate of 500 gpd, directly releasing all of the coolant activity to the environment. This release is assumed to continue for 65.75 hours, until the RCS has cooled to below 200 °F, at which time the release from this pathway terminates. The licensee used a transport model for

noble gases, iodine and particulates that is consistent with the guidance in Appendix E of RG 1.183.

The licensee assigned the remainder of the assumed 1 gpm primary-to-secondary side leakage, 0.65 gpm, to two of the three unaffected SGs. The licensee assumed that this leakage continues for 36.25 hours, until shutdown cooling is initiated and credited for decay heat removal. The licensee's analysis assumes that the third unaffected generator has a failed closed atmospheric dump valve. This conservative assumption reduces the holdup volume to that of two SGs instead of three. To maximize the release rate from this pathway, the licensee did not reduce the assumed steaming rate that would result from the assumption of a failed closed atmospheric dump valve on the third unaffected generator.

In order to ensure proper accounting of gross gamma, iodine and noble gas releases from the unaffected SGs, the licensee evaluated all the significant nuclide transport models for the MSLB accident. The licensee evaluated the release of the gross gamma activity from the primary coolant, at a level of fuel failure consistent with 1 uCi/gm DE I-131, leaking into the unaffected SG volume at a primary-to-secondary leak rate of 0.65 gpm. Radionuclides initially in the SG liquid and those entering the SG from the primary-to-secondary leakage flow are released as a result of secondary liquid steaming. An assumed PC of 100 results in 1 percent of the particulates and iodines in the SG bulk liquid being released to the environment at the steaming rate. Radionuclides initially in the steam space do not provide any significant dose contribution. The transport to the environment of noble gases from the primary coolant is assumed to occur without any mitigation or holdup.

The licensee used the RADTRAD-NAI computer code to model the time dependent transport of radionuclides, from the primary-to-secondary side and consequently to the environment via the ADVs. The licensee's analysis follows the guidelines of RG 1.183, Appendix E, which identifies acceptable radiological analysis assumptions for the MSLB. The licensee assumed the same CR ventilation timing sequence as was used for the SGTR as shown in Table 7, which does not credit automatic initiation of the CREVS.

Conclusion

The licensee evaluated the radiological consequences resulting from the postulated MSLB for SPU conditions and concluded that the radiological consequences at the EAB, LPZ, and CR are within the reference values provided in 10 CFR 50.67 and the accident-specific dose guidelines specified in SRP 15.0.1. The NRC staff's review finds that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.4 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 8, and the licensee's calculated dose results are given in Table 1. The NRC staff performed independent confirmatory dose evaluations, as necessary, to ensure a thorough understanding of the licensee's methods. The NRC staff finds that the EAB, LPZ, and CR doses estimated by the licensee for the MSLB meet the applicable accident dose guidelines and are, therefore, acceptable.

2.9.2.5 Primary Coolant Pump Locked Rotor Accident

The accident considered begins with the instantaneous seizure of a reactor coolant pump rotor, which causes a rapid reduction in the flow through the affected RCS loop. The sudden

decrease in core coolant flow, while the reactor is at power, causes a degradation of core heat transfer, resulting in localized temperature and pressure changes in the core. As a result, the licensee assumes that fuel damage occurs due to a DNB. Activity from the fuel damage is transported to the secondary side due to primary-to-secondary side leakage evaluated at the TS limit. It is assumed that the LRA does not cause an increase in the magnitude of the pre-existing primary-to-secondary leakage.

The licensee incorporated the assumption of a turbine trip (TT) and a coincident LOOP into the analysis. This results in a release through an assumed stuck open SG ADV and additional releases from the unaffected SGs. The stuck open ADV represents the assumed single active failure. The licensee stated that, consistent with the CLB, operator action to close the stuck open ADV is credited after 20 minutes.

As a result of the LRA, the licensee has determined that 7 percent of the fuel inventory gap activity would be released to the RCS. The RCS source term is assumed to be transported to the secondary side at the TS primary-to-secondary leakage limits of 1 gpm total with 500 gpd (0.35 gpm) assigned to the affected SG. The licensee assumed that the release from the affected SG continues for 20 minutes, at which point operator action is credited for the isolation of that release pathway.

The licensee assumed that the remainder of the primary-to-secondary leakage, 0.65 gpm, is released from the unaffected SGs over the course of 35.75 hours until shutdown cooling can be implemented to fully remove decay heat crediting only safety grade equipment. At this point, the release from the unaffected SGs is terminated when the operator closes the ADVs.

The licensee used the RADTRAD-NAI computer code to model the time-dependent transport of radionuclides, from the primary to secondary side and consequently to the environment via the ADVs. The licensee's analysis follows the guidelines of RG 1.183, Appendix G, which identifies acceptable radiological analysis assumptions for the LRA. The licensee assumed the same CR ventilation timing sequence as was used for the LOCA, which does not credit automatic initiation of the CREVS.

Conclusion

The licensee evaluated the radiological consequences resulting from the postulated LRA for SPU conditions and concluded that the radiological consequences at the EAB, LPZ, and CR are within the reference values provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP 15.0.1. The NRC staff's review finds that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.5 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 9, and the licensee's calculated dose results are given in Table 1. The NRC staff performed independent confirmatory dose evaluations, as necessary, to ensure a thorough understanding of the licensee's methods. The NRC staff finds that the EAB, LPZ, and CR doses estimated by the licensee for the LRA meet the applicable accident dose guidelines and are, therefore, acceptable.

2.9.2.6 Rod Control Cluster Assembly Ejection Accident

This accident is defined as the mechanical failure of a control rod mechanism pressure housing, resulting in the ejection of an RCCA and drive shaft. The consequence of this mechanical failure is a rapid positive reactivity insertion, together with an adverse core power distribution. For this accident, localized damage to fuel cladding and a limited amount of fuel melt are projected. The licensee assumed that as a result of localized fuel cladding damage, 10 percent of the gap activity is released to the primary coolant. In addition, the licensee assumes that 0.25 percent of the fuel inventory is also released to the primary coolant as a result of limited fuel melting. The mechanical failure breeches the reactor pressure vessel head resulting in a release of primary coolant to the containment atmosphere. Releases to the environment are assumed to occur through two separate pathways:

(1) Release of the containment atmosphere using design leakage assumptions; and

(2) Release of RCS inventory via primary-to-secondary leakage through SGs.

To evaluate the release to containment atmosphere, the licensee employed the guidance from Appendix H of RG 1.183. The licensee assumed that 10 percent of the fuel experiences fuel clad damage, releasing the fission product inventory in the fuel rod gap. The licensee assumed that 10 percent of the core inventory of iodines and noble gases resides in the fuel rod gap. Therefore, for the fuel clad failure, the fraction of core activity released is 0.01 for both halogens and noble gases. In addition, the licensee assumed that localized heating causes 0.25 percent of the fuel to melt, releasing 25 percent of the halogens and 100 percent of the noble gases contained in the melted fuel. As a result of the fuel melt portion of the fuel damage, the fraction of the core halogen activity released is 0.000625 (0.0025 x 0.25) and the fraction of noble gas activity released is 0.0025. The total activity released as a result of the fuel damage from the REA is the sum of the clad failure fraction and the fuel melt fraction. Therefore, the core release fractions assumed for the REA containment release pathway are, 0.010625 for halogens and 0.0125 for noble gases, based on the consequences of 10 percent fuel cladding failure and 0.25 percent melted fuel.

The licensee has conservatively assumed that containment sprays will not initiate due to an REA and, as a result, the licensee did not evaluate dose contributions from ECCS leakage and RWST back leakage as in the LOCA analysis. For the release into containment resulting from the REA, the licensee did not credit natural deposition as was done in the LOCA analysis. The licensee assumed that the containment leak rate is reduced by 50 percent at 24 hours for both the offsite and the CR analyses. The licensee has determined that an SI signal will be initiated 2 minutes after the accident. As a result, the licensee has assumed that the CR will not be isolated until 2 minutes 10 seconds following the REA.

The second release path evaluated by the licensee is via the secondary system. The licensee based the evaluation of the activity in the secondary system release on the guidance in Appendix H of RG 1.183. The core release fractions for halogens and noble gases are based on the assumed consequences of 10 percent failed fuel cladding and 0.25 percent melted fuel, as in the containment release case. To evaluate the fuel clad failure portion of the fuel damage, the fraction of core activity released is 0.01 for both halogens and noble gases, as in the containment release case. For the secondary release pathway, the licensee assumed that 50 percent of the iodines and 100 percent of the noble gases contained in the melted fuel are

released to the RCS. Therefore, as a result of the fuel melt portion of the fuel damage the fraction of the core halogen activity released to the RCS is 0.00125 (0.0025 x 0.5) and the fraction of noble gas activity released is 0.0025. Therefore, the core release fractions for the REA secondary release pathway are, 0.01125 for halogens and 0.0125 for noble gases, based on the consequences of 10 percent fuel cladding failure and 0.25 percent melted fuel.

For the secondary release case, the licensee assumed that fission products released from the fuel are instantaneously and homogeneously mixed in the RCS and transported to the secondary side of the SGs via primary-to-secondary leakage at the TS value of 1 gpm for 20 minutes. The licensee has determined that, for this event, a 20 minute time period is required for the primary system pressure to fall below the secondary side system pressure.

A LOOP is conservatively assumed to occur concurrently with the REA, rendering the MC unavailable. With the MC unavailable, the plant is cooled down by releases of steam to the environment via the ADVs and or the MSSV. During the first 20 minutes of the accident, the only steam release is assumed to be via the secondary safety valve. When the primary system pressure drops below the secondary side pressure, the safety valve closes. At 2 hours post-accident, a cooldown to the RHRS entry conditions is initiated. Steam releases are assumed to begin again at 2 hours and continue until 35.75 hours, at which time shutdown cooling can be implemented to fully remove decay heat crediting only safety grade equipment. The time to achieve the RHR entry condition of RCS temperature at 350˚F was conservatively delayed to 24 hours. This is followed by 11.75 hours of steaming concurrent with RHR operation.

The licensee assumed the chemical form of the iodines released from the SGs to be 97 percent elemental and 3 percent organic as is consistent with the applicable regulatory guidance. As in the evaluation of the MSLB accident, the licensee assumed an iodine partition factor of 100 in the SGs and assumed that the noble gas activity released to the secondary system is released to the environment without reduction or mitigation.

The licensee used the RADTRAD-NAI computer code to model the time dependent transport of radionuclides, from the primary to secondary side and consequently to the environment via the ADVs. The licensee's analysis follows the guidelines of RG 1.183, Appendix H, which identifies acceptable radiological analysis assumptions for the REA. The licensee assumed the same CR ventilation timing sequence as was used for the LOCA, which does not credit automatic initiation of the CREVS, except that the licensee has assumed that the CR will not be isolated until 2 minutes 10 seconds following the REA.

Conclusion

The licensee evaluated the radiological consequences resulting from the postulated REA for SPU conditions and concluded that the radiological consequences at the EAB, LPZ, and CR are within the reference values provided in 10 CFR 50.67 and the accident specific dose guidelines specified in SRP 15.0.1. The NRC staff's review finds that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.6 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 10, and the licensee's calculated dose results are given in Table 1. The NRC staff performed independent confirmatory dose evaluations, as necessary, to ensure a thorough understanding of the licensee's methods. The NRC staff finds that the EAB, LPZ, and CR doses estimated by

the licensee for the REA meet the applicable accident dose guidelines and are, therefore, acceptable.

2.9.2.7 Small Line Break Outside Containment

Section 15.6.2 of the MPS3 UFSAR describes the CLB evaluation for the failure of small lines carrying primary coolant OC. There are no instrument lines connected to the RCS that penetrate the containment. There are, however, sample lines from the hot legs of RCLs 1 and 3, from the cold legs of each RCL, and from the steam space of the pressurizer that do penetrate the containment. In addition, the post accident sampling system (PASS) lines, and the CVCS letdown and RCP seal return lines also penetrate the containment. The hot leg, cold leg, and pressurizer vapor space sample lines are provided with normally open automatic isolation valves on both sides of the containment wall. The PASS lines are provided with a normally closed automatic isolation valve inside containment and a locked closed remote-manual isolation valve OC. The CVCS letdown and RCP seal return lines are provided with normally open automatic containment isolation valves on both sides of the containment wall. In all cases the containment isolation valves are designed in accordance with the requirements of GDC 55 which states:

> Each line that is part of the RCPB and that penetrates primary reactor containment shall be provided with containment isolation valves as follows, unless it can be demonstrated that the containment isolation provisions for a specific class of lines, such as instrument lines, are acceptable on some other defined basis:
>
> (1) One locked closed isolation valve inside and one locked closed isolation valve OC; or
>
> (2) One automatic isolation valve inside and one locked closed isolation valve OC; or
>
> (3) One locked closed isolation valve inside and one automatic isolation valve OC. A simple check valve may not be used as the automatic isolation valve OC; or
>
> (4) One automatic isolation valve inside and one automatic isolation valve OC. A simple check valve may not be used as the automatic isolation valve OC.
>
> Isolation valves OC shall be located as close to containment as practical and upon loss of actuating power, automatic isolation valves shall be designed to take the position that provides greater safety.
>
> Other appropriate requirements to minimize the probability or consequences of an accidental rupture of these lines or of lines connected to them shall be provided as necessary to assure adequate safety. Determination of the appropriateness of these requirements, such as higher quality in design, fabrication, and testing, additional provisions for in-service inspection, protection against more severe natural phenomena, and additional isolation valves and containment, shall include consideration of the population density, use characteristics, and physical characteristics of the site environs.

The most severe pipe rupture, with regard to radioactivity release during normal plant operation, would be a complete severance of the 3-inch CVCS letdown line just OC, but between the

outboard letdown isolation valve and letdown heat exchanger, at rated power condition. The occurrence of a complete severance of the letdown line would result in a loss of reactor coolant at the rate of approximately 152 gpm which would not cause ESFs system actuation.

Area radiation and leakage detection instrumentation will provide the means for detection of a letdown line rupture. Frequent operation of the CVCS reactor makeup control system and other CVCS instrumentation will aid the operator in diagnosing a letdown line rupture. The time required for the operator to identify the accident and manually isolate the rupture is assumed to be within 30 minutes of the rupture. Once the rupture is identified, the operator would isolate the letdown line rupture by closing the letdown orifice isolation valves or the letdown line containment isolation valves. The letdown containment isolation valves are credited to close and isolate the leak. All valves are provided with control switches at the main control board. There are no single failures that would prevent isolation of the letdown line rupture.

The licensee evaluated the TEDE at the EAB from the worst-case small lines break (SLB) carrying primary coolant OC for MPS3 using the AST at SPU conditions. RG 1.183 does not provide specific guidance for the evaluation of the SLBOC and the licensee did not provide an AST analysis of the SLBOC in support of Amendment No. 232. Consistent with the CLB, the licensee evaluated the SLBOC for SPU conditions considering a break in a 3" letdown line for the CVCS. Consistent with the CLB evaluation, the licensee calculated doses at the EAB only for the SLBOC. The licensee used the methodology consistent with the guidance of RG 1.183 for coolant activity releases, in conjunction with TEDE radiological units and limits and dose conversion factors from FGR No. 11 and 12.

To maximize the dose consequence, the licensee assumed that the break occurs just OC, but between the outboard letdown isolation valve and letdown heat exchanger, at rated power conditions. Consistent with the CLB, the licensee assumed that the complete severance of the letdown line would result in a loss of reactor coolant at the rate of approximately 152 gpm, which may not cause ESFs system actuation.

The licensee assumed that a coincident iodine spike at 500 times the equilibrium iodine appearance rate occurs with the accident. Therefore, the licensee assumed that the 152 gpm leak contains primary coolant activity at TS limits in addition to the coincident spike activity. Consistent with applicable regulatory guidance, the concurrent iodine spike duration is assumed to be 8 hours. A portion of the leaked primary coolant is assumed to flash to steam, which will result in the airborne release of primary coolant activity based on the rate of flashing. Since the ESF systems may not actuate, the licensee assumed that the flashed primary coolant activity is released unfiltered directly to the environment as a ground level release.

The licensee assumed that the fraction of iodine released to the environment is 0.40 due to primary coolant flashing during pipe leakage. This is based on a direct release of primary coolant at primary coolant temperature, which conservatively bounds potential accident conditions. The licensee conservatively modeled all other nuclide groups assuming 100 percent flashing.

Area radiation and leakage detection instrumentation provide the means for detection of a letdown line rupture. Consistent with the CLB, the time required for the operator to identify the accident and manually isolate the rupture is assumed to be within 30 minutes of the rupture.

Conclusion

The licensee evaluated the radiological consequences resulting from the postulated SLBOC for SPU conditions. The licensee concluded that the radiological consequences at the EAB meet the applicable 2.5 rem TEDE limit stated in RG 1.183 for accidents that were previously limited to the small fraction, i.e. 10 percent, of the 10 CFR 100 limit. The NRC staff's review finds that the licensee used analysis assumptions and inputs consistent with applicable regulatory guidance identified in Section 2.9.2.7 of this SE. The assumptions found acceptable to the NRC staff are presented in Table 11, and the licensee's calculated dose results are given in Table 1. The NRC staff performed independent confirmatory dose evaluations, as necessary, to ensure a thorough understanding of the licensee's methods. The NRC staff finds that the EAB dose estimated by the licensee for the SLBOC meets the applicable accident dose guidelines and is, therefore, acceptable.

Control Room Habitability

The CREPS is designed to ensure that a positive pressure is maintained in the CR envelope for any event with the potential for radioactive releases. The positive pressure supplied by the CREPS limits CR inleakage and consequently dose to the CR occupants. With the implementation of the AST in Amendment No. 232, none of the associated radiological analyses credit the CREPS in the calculation of the dose to the CR occupants. Since the acceptance criterion is met for the radiological DBAs without crediting the CREPS, the licensee has eliminated the TS associated with the CREPS. However, the licensee did not physically remove the CREPS and has allowed time for the operation of the system, before initiating the CREVS, in the CR ventilation timing sequence for all the DBAs except for the SPU FHA, which credits the filtered recirculation portion of the CREVS at 30 minutes post-accident.

The CR effective volume used in the habitability analyses is 2.38E+05 ft^3. The normal CR ventilation intake flow rate prior to isolation is 1,595 cfm. The CR will isolate on a CBI signal from a SI signal for the LOCA and REA. For all other DBAs analyzed in this LAR, the CR will isolate on a CBI signal from the CR inlet radiation monitor.

The period after CBI and prior to CREVS initiation is referred to as the CR neutral condition. During the neutral condition, the CR is isolated, the normal ventilation flow rate of 1,595 cfm has terminated, and the CREVS is not operating. During the neutral condition there is no mechanically induced ventilation of the CR. For the neutral condition, the licensee conservatively has assumed an unfiltered inleakage of 350 cfm for use in CR habitability calculations. The licensee assumes that the 350 cfm of unfiltered inleakage continues for an additional 40 minutes, after the 61 minute time period allowed for CREPS operation, to enable the manual alignment of the CREVS. Therefore, the CR habitability analyses assume that the neutral condition described above, and the associated 350 cfm of unfiltered inleakage persists for a total of 101 minutes following CBI.

The CLB assumes that 101 minutes after CBI, the manual alignment of the CREVS will have been completed and the CREVS will be operational. In the SPU dose consequence analyses, the licensee maintains this conservative assumption, notwithstanding the implementation of automatic initiation of the CREVS on a CBI signal, for all accidents except the FHA. As stated previously, the licensee has assumed that for the SPU FHA, the filtered recirculation portion of the CREVS will initiate at 30 minutes post-accident.

The CREVS provides 230 cfm of filtered pressurization flow and 666 cfm of filtered recirculation flow to the CR. The period when the CREVS is providing pressurization flow is referred to as the CR positive pressure period. During the CR positive pressure period, the licensee assumes an unfiltered inleakage of 100 cfm, which is conservatively based on tracer gas testing results. Once initiated, CREVS operation and the associated CR positive pressure period persists for the duration of the event in the CR habitability analyses.

For the SPU analysis, the credited CREVS filter removal efficiencies were increased to 95 percent for aerosol, elemental and organic iodine. This change is supported by TS 3.7.7, which requires methyl iodide penetration of less than 2.5 percent and particulate penetration of less than 0.05 percent, as specified by RG 1.52,[183] for removal credit of 95 percent in the dose consequence accident analysis. The licensee assumed CR occupancy factors of 100 percent for the first 24 hours, 60 percent from 24 to 96 hours, and 40 percent from 96 to 720 hours.

The LOCA causes a CBI signal to isolate the CR. The control building is isolated within 5 seconds after a CBI signal. Following the guidance of the AST, as described in RG 1.183, the onset of the gap release is not assumed to begin until 30 seconds after the initiation of the LOCA. Therefore, for the LOCA the licensee assumed that the CR will be isolated prior to the arrival of the radioactive release. The CR is assumed to be in a neutral condition for 101 minutes until the CREVS is conservatively assumed to become fully operational.

For the REA, the CR ventilation assumptions are the same as the LOCA with the exception that the CR isolation is initiated based on the SI signal which occurs at 2 minutes post-accident. Therefore, the CR is not isolated until 2 minutes and 10 seconds following an REA and the normal unfiltered ventilation flow of 1,595 cfm persists for the first 2 minutes 10 seconds of the REA.

The licensee evaluated the CR habitability for a period of 720 hours notwithstanding the relatively short release duration of several of the DBAs evaluated; most notably the FHA, in which the release is assumed to end in 2 hours.

Atmospheric Dispersion Estimates

The licensee made no changes to the χ/Q values for the MP3 SPU radiological analyses for the EAB, LPZ, and CR as documented in UFSAR Table 15.0-11. The licensee maintained the CLB χ/Q values that were accepted by the NRC staff in License Amendment No. 211 dated September 16, 2002, to evaluate the impact of the SPU MPS3 postulated LOCA, FHA, SGTR, MSLB, LRA, REA and SLBOC radiological releases to the EAB and LPZ.

The licensee maintained the CLB χ/Q values that were accepted by the NRC staff in License Amendment No. 232, which approved the AST for MPS3 to evaluate the impact of the SPU MPS3 postulated LOCA, FHA, SGTR, MSLB, LRA, and REA radiological releases to the CR. For the SPU evaluations the licensee did not credit stack releases using the previously

[183] Regulatory Guide, "Design, Inspection, and Testing Criteria for Air Filtration and Adsorption Units of Post-Accident Engineered-Safety-Feature Atmosphere Cleanup Systems in Light-Water-Cooled Nuclear Power Plants," Revision 3, dated October 2000. (ADAMS Accession No. ML011710176)

accepted χ/Q values. For additional conservatism in the SPU analyses, the licensee evaluated all filtered releases assuming a discharge from the turbine building vent.

Conclusion

The NRC staff finds that the licensee used analysis methods and assumptions consistent with the conservative regulatory requirements and guidance identified in Section 2.9.2.1 of this SE. The NRC staff compared the doses estimated by the licensee to the applicable dose guidelines identified in Section 2.9.2.1. The NRC staff also finds, with reasonable assurance, that the licensee's estimates of the EAB, LPZ, and CR doses will comply with these guidelines. The NRC staff further finds reasonable assurance that the licensee, MPS3, as modified by this SPU license amendment, will continue to provide sufficient safety margins with adequate defense-in-depth to address unanticipated events and to compensate for uncertainties in accident progression and analysis assumptions and parameters. Therefore, the proposed SPU license amendment is acceptable with respect to the radiological consequences of DBAs.

Table 1
MPS3 SPU Radiological Consequences Expressed as TEDE [1]
(rem)

Design Basis Accidents	EAB [2]	LPZ [3]	Control Room
Loss of Coolant Accident	5.4E+00	1.1E+00	3.4E+00
Dose guidelines	2.5E+01	2.5E+01	5.0E+00
Fuel Handling Accident	2.7E+00	1.5E−01	4.8E+00
Dose guidelines	6.3E+00	6.3E+00	5.0E+00
Non Fuel component Drop Accident	---	---	4.3E+00
Dose guidelines	---	---	5.0E+00
Steam generator tube rupture [4]	2.2E+00	2.0E−01	3.3E+00
Dose guidelines	2.5E+01	2.5E+01	5.0E+00
Steam generator tube rupture [5]	1.0E+00	2.0E−01	1.7E+00
Dose guidelines	2.5E+00	2.5E+00	5.0E+00
Main steamline break accident [4]	9.6E−02	4.4E−02	1.6E+00
Dose guidelines	2.5E+01	2.5E+01	5.0E+00
Main steamline break accident [5]	4.0E−01	2.2E−01	3.6E+00
Dose guidelines	2.5E+00	2.5E+00	5.0E+00
Locked rotor accident	2.4E+00	4.4E−01	3.9E+00
Dose guidelines	2.5E+00	2.5E+00	5.0E+00
REA[6] Accident			
Containment	5.1E−01	2.5E−01	1.5E+00
Secondary side	1.2E−01	1.6E−02	5.1E−02
Dose guidelines	6.3E+00	6.3E+00	5.0E+00
Small line break outside Containment	2.5E+00	NA	NA
Dose guidelines	2.5E+00	NA	NA

[1] Total effective dose equivalent
[2] Exclusion area boundary
[3] Low population zone
[4] Pre-accident iodine spike
[5] Concurrent iodine spike
[6] Rod Control Cluster Assembly Ejection Accident

Table 2 (Page 1 of 2)
Control Room Atmospheric Dispersion Factors

Source Location / Duration		χ/Q (sec/m^3)
Turbine Building Ventilation Vent		
	0 - 2 hours	2.82E-03
	2 - 8 hours	1.65E-03
	8 - 24 hours	6.67E-04
	24 - 96 hours	4.83E-04
	96 - 720 hours	3.80E-04
Main Steam Valve Building Ventilation Exhaust		
	0 - 2 hours	1.46E-03
	2 - 8 hours	8.76E-04
	8 - 24 hours	3.42E-04
	24 - 96 hours	2.71E-04
	96 - 720 hours	1.96E-04
Containment Enclosure Building		
	0 - 2 hours	5.34E-04
	2 - 8 hours	3.23E-04
	8 - 24 hours	1.38E-04
	24 - 96 hours	8.78E-05
	96 - 720 hours	7.42E-05
Engineering Safety Features Building Ventilation Exhaust		
	0 - 2 hours	3.18E-04
	2 - 8 hours	2.26E-04
	8 - 24 hours	9.06E-05
	24 - 96 hours	6.42E-05
	96 - 720 hours	4.59E-05
Refueling Water Storage Tank Vent		
	0 - 2 hours	2.61E-04
	2 - 8 hours	1.59E-04
	8 - 24 hours	6.45E-05
	24 - 96 hours	4.83E-05
	96 - 720 hours	3.63E-05
Millstone Stack [1]		
	0 – 4 hours	1.39E-04
	4 - 8 hours	3.23E-05
	8 - 24 hours	1.56E-05
	24 - 96 hours	3.20E-06
	96 - 720 hours	3.30E-07

[1] Stack χ/Qs were not used in the analyses. For conservatism, the licensee assumed that all filtered releases are discharged from the turbine building vent.

Table 2 (Page 2 of 2)
Control Room Atmospheric Dispersion Factors

Source Location / Duration		χ/Q (sec/m^3)
Turbine Building		
	0 - 2 hours	5.40E-03
	2 - 8 hours	3.51E-03
	8 - 24 hours	1.38E-03
	24 - 96 hours	1.01E-03
	96 - 720 hours	8.49E-04

Table 3
Offsite Atmospheric Dispersion Factors (sec/m^3)

Source Location / Duration		χ/Q (sec/m^3)
Exclusion Area Boundary (EAB) (0 - 720 hours)		
	Containment	5.42E-04
	Millstone Stack (includes Fumigation) [1]	1.00E-04
	Other release points	4.30E-04
Low Population Zone (LPZ)		
Millstone Non-Stack Release Points		
	0 - 8 hours	2.91E-05
	8 - 24 hours	1.99E-05
	24 - 96 hours	8.66E-06
	96 - 720 hours	2.63E-06
Millstone Stack (includes fumigation) [2]		
	0 - 4 hours	2.69E-05
	4 - 8 hours	1.07E-05
	8 - 24 hours	6.72E-06
	24 - 96 hours	2.46E-06
	96 - 720 hours	5.83E-07

[1] Stack χ/Qs were not used in the analyses. For conservatism, the licensee assumed that all filtered releases are discharged from the turbine building vent using a χ/Q of 4.3E-04 sec/m^3.

[2] Stack χ/Qs were not used in the analyses. For conservatism, the licensee assumed that all filtered releases are discharged from the turbine building vent using the Millstone non-stack release point χ/Q values.

Table 4
MPS3 Control Room Data and Assumptions

CR effective volume		2.38E+05 ft^3
Normal CR intake flow rate prior to isolation		1595 cfm
Unfiltered inleakage during periods of neutral pressure		350 cfm
Unfiltered inleakage during periods of positive pressure		100 cfm
CREVS recirculation flow rate		666 cfm
CREVS pressurization flow rate		230 cfm
Response time for CR inlet radiation monitor to generate CBI signal – validated for each accident analysis		5 seconds
Response time for CR to isolate upon receipt of CBI		5 seconds
Time allotted for delay of CREPS		1 minute
Time allotted for CREPS discharge to the CR (CREPS is not credited in any dose analyses)		60 minutes
Time allotted for operator action to align CREVS after completion of CREPS discharge		40 minutes
Total time allotted to place CREVS in service (summation of the 3 preceding time intervals)		101 minutes after CBI signal
Filter Efficiencies for CREVS		
	Elemental	95%
	Aerosol	95%
	Organic	95%
CR occupancy factors		
	0 - 24 hours	1.0
	24 - 96 hours	0.6
	96 - 720 hours	0.4
Breathing rate for CR dose analyses		3.5E-04 m^3/sec

The following data is used to calculate the containment shine component of the CR dose

Containment free air volume	2.35E+06 ft^3
Containment wall thickness	4.5 ft concrete
Containment dome thickness	2.5 ft concrete
Distance from containment to CR	228 ft
Containment inner radius	70 ft
Control building wall thickness	2 ft concrete
CR ceiling thickness	8 inches concrete
Control building roof thickness	1 ft -10 in concrete

Table 5 (Page 1 of 2)
MPS3 SPU Data and Assumptions for the LOCA

Power Level for all DBAs		3723 MWt: 3650 MWt + 2% uncertainty
Containment free air volume		2.35E+06 ft^3
Containment leak rate		0.3% by weight per day (L_a)
Containment bypass leak rate		$0.06L_a$
Containment leak rate reduction		50% after 24 hours (offsite analyses) 50% after 1 hour (CR analysis)
Secondary containment drawdown time		2 minutes
Iodine chemical form in containment atmosphere		
	Cesium iodide	95%
	Elemental iodine	4.85%
	Organic iodine	0.15%
Iodine chemical form released to the atmosphere from ESF and RWST leakage		
	Elemental	97%
	Organic	3%
Containment sump pH		$\geq$ 7
SLRCS filter efficiency		95% all iodines and particulates
Auxiliary building filter efficiency		95% all iodines and particulates
QSS effective period of operation		80 to 10,000 seconds
RSS period of operation		5500 seconds to 30 days
QSS flow rate		28,846 ft^3/hr
RSS flow rate		17,308 ft^3/hr
Elemental iodine removal coefficient		10 per hour
QSS particulate iodine removal coefficient		11.5 per hour
Particulate iodine removal coefficient for combined QSS and RSS operation		DF < 50: 13.7 per hour DF > 50: 1.36 per hour
RSS only particulate iodine removal coefficient		0.65 per hour
Time at which DF of 50 is reached for particulate iodine		2.063 hours
QSS containment coverage volume		1,166,200 ft^3
QSS and RSS containment coverage volume		1,515,858 ft^3
RSS only containment coverage volume		1,102,000 ft^3
Mixing rate between sprayed and unsprayed volumes		2 volumes of the unsprayed region per hour
Natural deposition in the unsprayed region		Power's model at 10th percentile

Table 5 (Page 2 of 2)
MPS3 SPU Data and Assumptions for the LOCA

ECCS leakage outside containment		
	Controlled limit	4,730 cc/hr
	Analysis value	10,000 cc/hr
Start of ECCS leakage		2500 seconds
Sump temperature at start of ECCS leakage		230˚F
ECCS conservative flashing fraction used in analysis		10%
Sump volume (variable)		
	2000 seconds	1E+05 gallons
	8000 seconds	7.5E+05 gallons
Minimum available RWST volume		1,072,886 gallons
Minimum QSS auto trip value		47,652 gallons
RWST maximum fill volume		1,206,644 gallons
RWST backleakage integrated flow rates		
	Time (hours)	Flow rate (cfm)
	4.25	0.03
	14.91	0.11
	18.46	0.13
	33.74	0.16
	63.13	0.19
	68.83	0.21
	72.21	0.24
RWST breathing rate		8.7 cfm
RWST air holdup volume		1.549E+05 ft^3
Quantity of iodine in the core at EOC		26,000 grams
Maximum iodine concentration in the RWST		1.5 mg/liter
DF used in RWST backleakage		100

CR ventilation timing:

T= 0 seconds	CR isolated on SI signal Intake flow: 0 cfm; neutral condition Assumed unfiltered inleakage: 350 cfm
T= 1 minute	delay for CREPS response (Not credited) Assumed unfiltered inleakage: 350 cfm
T=1 hour, 41 min (1.685 hours)	CREVS filtered intake flow: 230 cfm Assumed unfiltered inleakage: 100 cfm CREVS filtered recirculation flow: 666 cfm

Table 6
MPS3 SPU Data and Assumptions for the FHA

Number of assemblies in full core		193
Number of rods in an assembly		264
Fuel clad damage		1 assembly plus 19 rods; 283 rods total
Percentage of high burnup fuel rods		67% exceed values in RG 1.183, note 11
Gap Fractions assumed in high burnup rods		
	I-131	0.12
	Kr-85	0.30
	Remainder of noble gases	0.10
	Remainder of halogens	0.10
Gap Fractions assumed in non high burnup rods		
	I-131	0.08
	Kr-85	0.10
	Remainder of noble gases	0.05
	Remainder of halogens	0.05
Pool decontamination factor		
	Noble gases	1
	Halogens (effective DF)	200
Release points		Turbine Building Ventilation Stack
		Enclosure Building / Containment Ground
Decay time		100 hours
Radial peaking factor		1.7
Duration of release to the environment		2 hours
CR ventilation timing:		Unique to the SPU FHA analysis
	T= 0 seconds	Normal CR unfiltered intake flow of 1595 cfm
	T= 5 seconds	CBI signal generated
		CREPS receives CBI signal
	T= 10 seconds	CR isolates on radiation monitor signal
		Intake flow: 0 cfm; neutral condition
		Assumed unfiltered inleakage: 350 cfm
	T= 1 minute, 5 seconds	delay for CREPS response (Not credited)
		Assumed unfiltered inleakage: 350 cfm
	T= 30 minutes	Filtered recirculation flow: 666 cfm
		Assumed unfiltered inleakage: 350 cfm
	T=1 hour, 41 min, 5 sec	CREVS filtered intake flow: 230 cfm
	(1.685 hours)	Assumed unfiltered inleakage: 100 cfm
		CREVS filtered recirculation flow: 666 cfm

Table 7 (Page 1 of 2)
MPS3 SPU Data and Assumptions for the SGTR Accident

Primary-to-secondary leak rate TS limit		150 gpd to any 1 SG
LOOP		Coincident with release
RCS TS iodine limit for normal operation		1.0 µCi/gm DEI
	Gross gamma	Equivalent to fuel failure associated with DEI limit
Secondary iodine TS limit		0.1 µCi/gm DEI
RCS TS limit for pre-accident iodine spike		60 µCi/gm DEI
Coincident spike appearance rate multiplier		335
Iodine spike duration		8 hours
Release points		SG ADVs
Credited operator actions		
	Secure release from affected SG	0.7506 hours
	Secure release from unaffected SGs	35.75 hours
Chemical form of iodine released from SGs		
	Elemental	97%
	Organic	3%
Iodine Partition coefficient		100
Moisture carryover in unaffected SGs		1%
Tube uncovery		None
Duration of release to environment		
	Unaffected SGs	0 - 35.75 hours
	Affected SG	0 - 0.7506 hours & 2 - 11 hours
	NG from ruptured SG	0 - 1.781 hours (duration of break flow)
Assumed RCS volume		
	For preaccident spike	11,750 ft^3
	For concurrent spike	10,000 ft^3
Assumed RCS mass		
	For preaccident spike	5.194E+05 lbm
	For concurrent spike	4.439E+05 lbm
Initial SG steam mass		
	For preaccident spike	8,870 lbm/SG
	For concurrent spike	8,422 lbm/SG
Initial SG liquid mass		
	For preaccident spike	97,222 lbm/SG
	For concurrent spike	100,933 lbm/SG

Additional assumptions:
Dose consequence from the release of initial secondary side steam is not significant

CR plume and CR filter shine dose conservatively set at values from the LOCA analyses

Table 7 (Page 2 of 2)
MPS3 SPU Data and Assumptions for the SGTR Accident

Time line of events in the DBA SGTR accident

Seconds	Hours	Event description
0	0	SGTR – ADV sticks open – LOOP
10	0.0028	CR isolates
135	0.0375	Reactor trip
143	0.0397	SI actuated
1500	0.4167	Affected SG isolated
1502	0.4172	Affected SG ADV fails open
2702	0.7506	Affected SG ADBV closed terminating release from affected SG
3381	0.9392	Flashing of the break flow terminated
6065	1.685	CREVS initiated
6412	1.781	Break flow terminated
7200	2	Affected SG depressurization and release from affected SG re-initiated
	11	Affected SG depressurized, release terminated
	24	RCS cooled to 350˚F allowing RHRS to be placed in service
	35.75	RHRS capable of 100% of cooldown ending release from unaffected SGs
	720	End of DBA SGTR analysis period

CR ventilation timing for the SGTR:

T= 0 seconds	Normal CR unfiltered intake flow: 1595 cfm
T= 5 seconds	CBI signal generated
T= 10 seconds	CR isolates on radiation monitor signal Intake flow: 0 cfm; neutral condition Assumed unfiltered inleakage: 350 cfm
T= 1 minute, 5 seconds	delay for CREPS response (Not credited) Assumed unfiltered inleakage: 350 cfm
T=1 hour, 41 min, 5 sec (1.685 hours)	CREVS filtered intake flow: 230 cfm Assumed unfiltered inleakage: 100 cfm CREVS filtered recirculation flow: 666 cfm

Table 8 - MPS3 SPU Data and Assumptions for the MSLB Accident

RCS volume		11,750 ft^3
RCS mass		5.216E+05 lbm
Primary-to-secondary leak rate TS limit		150 gpd to any 1 SG
RCS TS iodine limit for normal operation		1.0 µCi/gm DEI
	Gross gamma	Equivalent to fuel failure associated with DEI limit
Secondary iodine TS limit		0.1 µCi/gm DEI
RCS TS limit for pre-accident iodine spike		60 µCi/gm DEI
Coincident spike appearance rate multiplier		500
Iodine spike duration		8 hours
LOOP		Assumed to occur at accident initiation
Release points		
	Affected SG	Turbine building
	Unaffected SGs	ADVs
Iodine PC for unaffected SGs		100
Moisture carryover in unaffected SGs		1%
Primary-to-secondary leakage		
	Affected SG	500 gpd
	Total	1 gpm
SG liquid mass		165,000 lbm
Duration of SG release:		
	Affected SG	65.75 hours (RCS at 200˚F)
	Unaffected SG	36.25 hours (RHRS operation)
Steam release from affected SG		
	Initial inventory	6E+05 lbm/min (0 - 16.5 sec)
	Primary-to-secondary leak	2.918 lbm/min (0 – 65.75 hrs)
Steam Release from unaffected SGs		
	0 - 2 hours	3.58E+03 lbm/min
	2 - 11 hours	2.37E+03 lbm/min
	11 - 24 hours	2.37E+03 lbm/min
	24 - 36.25	2.73e+02 lbm/min
CR ventilation timing for the MSLB:		
	T= 0 seconds	Normal CR unfiltered intake flow: 1595 cfm
	T= 5 seconds	CBI signal generated
	T= 10 seconds	CR isolates on radiation monitor signal Intake flow: 0 cfm; neutral condition Assumed unfiltered inleakage: 350 cfm
	T= 1 minute, 5 seconds	delay for CREPS response (Not credited) Assumed unfiltered inleakage: 350 cfm
	T=1 hour, 41 min, 5 sec (1.685 hours)	CREVS filtered intake flow: 230 cfm Assumed unfiltered inleakage: 100 cfm CREVS filtered recirculation flow: 666 cfm

CR plume and CR filter shine dose are 4.37E-03 and 0.26 rem, respectively

Table 9
MPS3 SPU Data and Assumptions for the LRA Accident

Fuel clad failure		7%
Radial peaking factor		1.7
Primary-to-secondary leak rate		
	Affected SG	0.35 gpm
	Unaffected SGs	0.65 gpm
Release from secondary side		Coincident with LOOP
RCS volume		10,000 ft^3
RCS mass		4.439E+05 lbm
SG mass		100,933 lbm
CLB credited operator actions		Closure of ADV after 20 minutes
Release points		SG ADV
Chemical form of iodine released from SGs to the environment		
	Elemental iodine	97%
	Organic iodide	3%
Fraction of fission product inventory in gap		
	Halogens	0.8
	Noble gases	0.10
	Alkali metals	0.12
Iodine PC in unaffected SG		100
SG tube uncovery	Affected	Immediate dry out; 100% flashing assumed
	Unaffected	None
Discharge rate from the affected SG ADV		820,000 lb/hr
Release Duration		
	Affected SG	20 minutes
	Unaffected SGs	35.75 hours
Total mass of steam to atmosphere from unaffected SGs		
	0 - 2 hours	432,000 lbm
	2 - 11 hours	1,328,000 lbm
	11 - 24 hours	1,918,222 lbm
	24 - 35.75 hours	196,515 lbm
Mass flow rates from unaffected SGs		
	0 - 2 hours	2.16E+05 lbm/hr
	2 - 8 hours	1.48E+05 lbm/hr
	8 - 11 hours	1.48E+05 lbm/hr
	11 - 18 hours	1.67E+04 lbm/hr
Moisture carryover in unaffected SG		1%
MPS3 SG ADV maximum flow rate		820,000 lbm/hr @ 1140 psia
CR ventilation timing		Same as the LOCA

Additional assumptions:
Dose consequences are assessed for the initial release of secondary side liquid only
CR ventilation timing is the same as the SGTR
CR plume and CR filter shine dose conservatively set at values from the LOCA analyses

Table 10
MPS3 SPU Data and Assumptions for the REA

Containment free air volume	2.35E+06 ft^3
RCS mass	4.458E+05 lbm
Fraction of fuel clad failure	0.1
Fraction of core inventory in gap	
Noble gasses	0.1
Iodine	0.1
Fraction of core fuel melt	0.0025
Release fractions for melted fuel	
Containment release	
Noble gasses	1.0
Iodines	0.25
Secondary side release	
Noble gasses	1.0
Iodines	0.5
SI signal initiated after REA	2 minutes
Chemical form of iodine released from SGs to the environment	
Elemental iodine	97%
Organic iodide	3%
Total primary-to-secondary leakage through all SGs	1 gpm
Time for primary system pressure to fall below secondary system pressure	1,200 seconds
Duration of steam releases	35.75 hours
Steam released from 0 to 1,200 seconds (primary system depressurization)	200,000 lbm
Steam released from 2 - 11 hours	1,328,000 lbm (2,459 lbm/min)
Steam released from 11 - 24 hours	2,459 lbm/min
Steam released from 24 hours - 35.75 hours	280 lbm/min
SG liquid contents	100,933 lbm
CR ventilation timing	
Time for CR isolation	2 minutes 10 seconds
Remainder of CR ventilation timing	Same intervals after CBI as in the LOCA analysis

CR plume and CR filter shine dose conservatively set at values from the LOCA analyses

Table 11
MPS3 SPU Data and Assumptions for the SLBOC

Time to isolate letdown line	30 minutes
Break flow	152 gpm (1268 lbm/min)
Iodine flashing fraction	0.4
Flashing fraction for remainder of isotopes	1.0
Pipe break diameter	3 inches
RCS mass	4.483E+05 lbm
EAB χ/Q	5.42E-04 sec/m^3
Breathing rate	3.5E-04 m^3/sec

Table 12
MPS3 SPU Concurrent iodine spike RCS appearance rates, µCi/sec

Nuclide	Appearance rate for 1 µCi/gm DEI	Spike = 335 SGTR	Spike = 500 MSLB/SLBOC
I-131	6.06E+03	2.03E+06	3.03E+06
I-132	7.86E+03	2.63E+06	3.93E+06
I-133	1.12E+04	3.76E+06	5.61E+06
I-134	9.46E+03	3.17E+06	4.73E+06
I-135	9.44E+03	3.16E+06	4.72E+06

2.10 Human Performance

2.10.1 Human Factors

Regulatory Evaluation

The area of human factors deals with programs, procedures, training, and plant design features related to operator performance during normal and accident conditions. The NRC staff's human factors evaluation was conducted to ensure that operator performance is not adversely affected as a result of system changes made to be implemented the proposed SPU. The NRC staff's review covered changes to operator actions, human-system interfaces, and procedures and training needed for the proposed SPU. The NRC's acceptance criteria for human factors are based on GDC 19, 10 CFR 50.120, 10 CFR Part 55, and the guidance in GL 82-33. Specific review criteria are contained in SRP Sections 13.2.1, 13.2.2, 13.5.2.1, and 18.0.

Technical Evaluation

The NRC staff has developed a standard set of questions for the review of the human factors area. The licensee has addressed these questions in its application. Following are the NRC staff's questions, the licensee's responses, and the NRC staff's evaluation of the responses.

Changes in Emergency and Abnormal Operating Procedures

This section evaluates how the proposed SPU will change the plant emergency and abnormal operating procedures (AOPs).

The licensee stated in its submittal that the current EOPs and AOPs were reviewed for potential changes due to the proposed SPU. The identified changes include modifications required for parameter thresholds and graphs, which depend on the power and decay heat levels and changes to current setpoints. The licensee identified the following as the necessary and significant changes to the EOPs and AOPs:

(1) AOPs and EOPs will reflect the increase in flow requirements for AFW flow as a result of the proposed SPU. DNC will also revise the AOPs and EOPs to ensure that the CREVS is automatically placed in the filtered recirculation MODE of operation within 30 minutes of a FHA. The change in procedures will not add any new manual operator actions.

(2) There will be an additional manual action in the EOPs to verify ECCS flow when RCS pressure is less than 1900 psia. The operators will be required to check the charging pumps throughout the EOPs and ensure that a charging pump or SI pump is running. When determining if reactor coolant pumps should be stopped throughout the EOPs, the operators are required to perform an additional check to observe at least one of the charging or SI pumps is "capable of delivering flow to the RCS." This check is in addition to ensuring that a charging or SI pump is

running. Also, during the response to a loss of heat sink event, when verifying an RCS feed path, a new step for opening the cold leg injection valves is added.

(3) The licensee identified changes to the EOPs concerning the SGTR accident scenarios. The licensee evaluated the times required for the operator actions for the credited analysis of this accident scenario. The current analysis in the UFSAR assumed isolation when the SG level reached 29 percent narrow range or at 16.5 minutes whichever is longer. In their SPU analyses, the AFW isolation to the SG is assumed to occur when the SG is at 30 percent narrow range. The analysis no longer selects an arbitrary time associated with completion of the operator action. The licensee states that the operators are trained to isolate the flow when the narrow range in the ruptured SG reaches 8 percent due to the modeling for dose input analysis. The licensee stated that operator training experience has consistently shown that the operator will isolate the ruptured SG before the SG level reaches 30 percent because of this training. The operator actions credited in the analysis are based on operator training experience and are consistent with Westinghouse Owner's Group Emergency Operating Procedures as discussed in the reactor systems portion of the safety evaluation. The staff finds this change acceptable because of the operating experience results gathered from operator training.

(4) The other change the licensee identified concerning the SGTR accident scenario involved the operator action time to initiate the safety injection termination. The staff reviewed the documents and noted that the operator time to initiate safety injection termination was increased from 3 to 6 minutes, and the licensee stated that the plant/system response times changed as a result of the thermal hydraulic analysis. The staff reviewed this change and accepts this change due to the increase in time for the operator action. This change is more conservative concerning human performance because the licensee identified no change to the actual operator action and the time available for the operator to initiate the action has increased due to the proposed SPU.

The licensee identified no changes to event mitigation strategies. The licensee will reflect the changes to these manual operator actions through updating the appropriate procedures and addressing these changes in the operator training program through formal classroom and simulator training. The addition of these manual actions will be validated on the simulator during operator training prior to SPU implementation. The revisions to the EOPs and AOPs are being done to reflect the higher power level and minor setpoint changes, which will be made prior to SPU implementation.

The NRC staff has reviewed the licensee's assessment of the significant changes of the proposed SPU on MPS3 EOPs and AOPs. The NRC staff concludes that the proposed SPU does not present any adverse impacts on the EOPs and AOPs. This conclusion is based upon the licensee making revisions for these changes to the EOPs and AOPs that will reflect the new power level and revised setpoints. The changes being made to the EOPs and AOPs will be reflected in the operator training program prior to SPU implementation.

Changes to Operator Actions Sensitive to Power Uprate

This section evaluates any new manual operator actions needed as a result of the proposed SPU and changes to any current manual operator actions related to emergency or AOPs that will occur as a result of the proposed SPU.

The licensee identified two manual operator actions, which will require changes due to additional response time or reduced time available as a result of the proposed SPU. The first change involves a reduction of the time allowed from 9 hours to 5 hours for operators to initiate hot and cold leg recirculation to minimize boron precipitation for LB LOCAs. This time reduction does not involve a change to the actual completion time for the operator action. The available actual time only covers the initiation of hot leg recirculation, which involves realigning the ECCS to provide safety injection flow to the hot legs. Based on the complexity of the actions requiring plant power changes and the proposed time available for the initiation of the hot and cold leg recirculation, the staff finds that the manual operator actions required to support the proposed SPU are acceptable.

The next change involves the operator performing abnormal procedures requiring plant power changes. As a result of the proposed SPU, the automatic rod withdrawal function is disabled, which will require the operators to manually withdraw rods to maintain T_{avg}. This change will not increase the time associated with the manual operator actions in the AOPs. The licensee stated that inserting this manual action would be a more conservative approach for maintaining T_{avg} due to the nuclear instrumentation for MPS3 not being qualified for the environment resulting from a steam line break inside containment event. The MPS3's UFSAR postulates that the nuclear instrumentation can fail such that the rod control system would withdraw control rods, which would increase reactor power. A steam line break coincident with rod withdrawal event is currently the limiting MPS3 DNBR. In anticipation that the SPU would result in a loss of DNBR margin, a modification will be made to the rod control system to eliminate the automatic rod withdrawal capability. DNBR is discussed further in the reactor systems portion of the safety evaluation.

The licensee's review of all other operator actions for MPS3 sensitive to the SPU concluded that those manual operator actions will continue to be bounded and supported by the current UFSAR Chapter 15 analyses.

The NRC staff has reviewed the licensee's statements in the submittal relating to any impacts of the proposed SPU to existing or new operator manual actions. The NRC staff concludes that the proposed SPU will not adversely impact the overall existing manual operator actions and their response times.

Changes to Control Room Controls, Displays and Alarms

This section evaluates any changes the proposed SPU will have on the operator interfaces for CR controls, displays, and alarms.

In its submittal, the licensee described changes to CR controls, displays, and alarms related to the proposed SPU. Notable proposed changes to controls, displays, and alarms include:

(1) Calibration range, scaling or transmitter changes to turbine throttle and intermediate pressure scales;

(2) Alarm response procedures for PRT high and low level alarms require revision as a result of setpoint changes and changes in plant response to transients;

(3) Setpoints will be changed for the various parameters including main feedwater and MSS alarms, RCS delta-T alarm, RCS Tavg, pressurizer level, OTΔT/OPΔT reactor trip, turbine control valve setpoints, first stage pressure, turbine-driven feedwater pump control setpoint (Master Speed Control), P-8 permissive, cold leg injection permissive on low RCS pressure for ECCS, pressure relief tank level alarm, condenser steam dump trip valve control deadband and modulation; and

(4) Control systems changed as a result of the SPU include pressurizer level program, elimination of control rod automatic withdrawal, Thot filter addition, RCS Tavg program.

The operations department will be involved in the modification process, the procedural changes and the modification of the operator training program as a result of the SPU.

The purpose of this section is to assure that the licensee has adequately considered the equipment changes resulting from the SPU that affect the operators' ability to perform required functions. The NRC staff finds the proposed changes acceptable based upon the licensee implementing its change process to address the SPU-related changes in the CR and the corresponding operator training and simulator modifications prior to SPU implementation. The NRC staff has reviewed the licensee's evaluation and proposed changes to the CR. The NRC staff concludes that the proposed changes discussed above do not present any adverse effects to the operators' functions in the CR. The licensee stated that all modifications to the CR and the associated changes to operator training will take place prior to SPU implementation. These proposed CR changes will not alter existing requirements for the CR as stated in GDC 19.

Changes on the Safety Parameter Display System

The Safety Parameter Display System (SPDS) will be revised to address the changes to the CR controls, displays and alarms described in the previous section. The critical safety function status trees will also be reviewed and revised for the appropriate setpoint changes. These changes will be addressed through the plant change process.

The NRC staff reviewed the proposed changes to the SPDS as described by the licensee in its submittal. The staff finds the proposed changes to the SPDS acceptable based on the statements by the licensee that the changes will not be extensive and that the changes will not impact the operator's ability to monitor safety functions.

Changes to the Operator Training Program and the Control Room Simulator

This section evaluates any changes to the operator training program and the plant-referenced CR simulator resulting from the proposed SPU and the implementation schedule for making the changes.

The licensee stated that the plant simulator will reflect the CR changes to be made due to the SPU. SPU modifications will be reviewed to determine the impact on the simulator. The simulator configuration will be controlled through the established simulator change process for MPS3. Any changes to the control board hardware, indicators, scaling, and simulator modeling will be scheduled to accommodate the operator training program requirements prior to implementation of SPU conditions.

The licensee stated in its submittal that the licensed and non-licensed operator training programs employ the "Systematic Approach to Training" process in accordance to 10 CFR 50.120. This process has provisions for ensuring training is provided for plant modifications prior to SPU implementation. The licensee also plans to provide "Just-In-Time" training operations crews conducting the Infrequently Conducted/Complicated Evolution startup. This training will also cover the startup-testing plan both in the classroom and on the simulator. The MPS3 operations department will be involved in the SPU modification and procedure review process by providing input and gaining knowledge of the plant changes. The changes in EOPs and AOPs will also be reviewed, verified, and validated by operations personnel.

The licensee identified several required changes to training as a result of the SPU including changes to TSs, plant procedures, the training simulator, and training lesson plans. The NRC staff has reviewed the licensee's proposed changes to the operator training and plant simulator related to the SPU. The NRC staff concludes that the changes do not present any adverse effects on the plant simulator or the operator training program. The licensee stated that all the required modifications to the plant simulator and incorporated these changes into the operator training program will be made prior to SPU implementation. The NRC staff concludes that the licensee's proposed changes to the operator training program, including simulator training, are acceptable for the proposed SPU.

Conclusion

The NRC staff has reviewed the changes to operator actions, human-system interfaces, procedures, and training required for the proposed SPU and concludes that the licensee has: (1) appropriately accounted for the effects of the proposed SPU on the available time for operator actions; and (2) taken appropriate actions to ensure that operator performance is not adversely affected by the proposed SPU. The NRC staff further concludes that the licensee will continue to meet the requirements of GDC 19, 10 CFR 50.120, and 10 CFR Part 55 following implementation of the proposed SPU. Therefore, the NRC staff finds the licensee's proposed SPU acceptable with respect to the human factors aspects of the required system changes.

3.0 FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION CHANGES

3.1 Facility Operating License

To achieve the SPU, the licensee proposed the following changes to the Renewed Facility Operating License and TSs for MPS3.

Accordingly, Renewed Facility Operating License NPF-49, Paragraph 2C.(1), Maximum Power Level is changed to read as follows:

> (1) Maximum Power Level
>
> DNC is authorized to operate the facility at reactor core power levels not in excess of 3,650 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

The NRC staff finds this change acceptable because it is reflected in the technical reviews performed in Section 2.0.

3.2 Technical Specifications

The NRC's requirements related to the content of the TSs are set forth in 10 CFR 50.36, "Technical specifications." This regulation requires that the TSs include items in five specific categories. These categories include: (1) safety limits, limiting safety system settings and limiting control settings, (2) limiting conditions for operation (LCOs), (3) SRs, (4) design features, and (5) administrative controls.

Section 50.36(d)(2)(ii) of 10 CFR states that a TS LCO must be established for each item meeting one or more of the following criteria:

Criterion 1: Installed instrumentation that is used to detect, and indicate in the control room, a significant abnormal degradation of the reactor coolant pressure boundary.

Criterion 2: A process variable, design feature, or operating restriction that is an initial condition of a design basis accident or transient analysis that either assumes the failure of, or presents a challenge to the integrity of a fission product barrier.

Criterion 3: A structure, system, or component that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that either assumes the failure of, or presents a challenge to the integrity of a fission product barrier.

Criterion 4: A structure, system, or component which operating experience or probabilistic risk assessment has shown to be significant to public health and safety.

Section 50.36(d)(1)(ii)(A) of 10 CFR states, “Where a limiting safety system setting is specified for a variable on which a safety limit has been placed, the setting must be so chosen that automatic protective action will correct the abnormal situation before a safety limit is exceeded.” Furthermore, Section 50.36(d)(3) states, “Surveillance requirements are requirements relating to test, calibration, or inspection to assure that the necessary quality of systems and components is maintained, that facility operation will be within safety limits, and that the limiting conditions of operation will be met.”

The staff reviewed the following TS changes proposed by the licensee.

TS Definitions

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

The NRC staff finds this change acceptable because it is reflected in the technical reviews performed in Section 2.0.

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.

The NRC staff finds this change acceptable because it is reflected in the transient and safety analyses. The thermal hydraulic and transient and safety analyses were performed using reference cores comprised entirely of RFA/RFA-2 fuel assemblies.

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 the corresponding footnote is deleted. No change to the NTS or AV is proposed.

The licensee stated that this change is provided to add clarity to the TSs, in that the requirement can be more accurately described as nominal loop flow. The NRC staff finds this technical specification change acceptable.

The licensee provided additional information to show that the TS Bases were also revised to reflect this change. The Bases correctly identify the nominal RCS flow as the actual measured RCS flow during power operation. The NRC staff does not have any concerns with the TS bases.

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

The RTS Interlock- Power Range Neutron Flux, P-8 NTS is increased from 37.5 percent to 50.0 percent and the AV is increased from ≤38.1 percent to ≤50.6 percent of RTP.

The licensee stated that the plant Loss of Flow/Locked Rotor Analysis for the SPU showed that a value of 60 percent RTP for P-8 is acceptable. Based on that analysis, a conservative NTSP value of 50 percent is selected as the P-8 permissive. The staff noticed that this 10 percent RTP allowance between the AV and the proposed NTSP far exceeds the loop uncertainty for the P-8 signal loop in the WCAP. The proposed AV uses the same rack calibration value of 0.6 percent as for the existing TS for this functional unit. The licensee stated that the same plant equipment will be used to generate the new setpoint for this permissive. The staff also agreed with the licensee that because this functional unit is for P-8 permissive it is not safety-limit related.

The licensee adequately demonstrated the acceptability of this change and the NRC staff concludes that it is acceptable, as discussed in Section 2.8 of this SE.

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 Tavg and ΔT, to smooth out temperature spikes observed in the T_{ho}t 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.

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 by the licensee. As a result of the licensee's optimization study, the licensee 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) of the licensee's submittal dated July 13, 2007, the DNBR analysis shows that the DNBR limits will be met for all UFSAR 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. The NRC staff agrees with the licensee's analysis and finds this change acceptable.

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.

This change is supported by the transient and accident analyses, assuming an RCS design flow of 363,200 gpm with 10-percent SG tube plugging. As the change is supported by the licensee's analysis, the NRC staff concludes that this change is acceptable.

Surveillance Requirement 4.2.3.1.2 is being changed and separated into two parts, one for F_N ΔH and other for the RCS total flow rate as follows:

SR 4.2.3.1.2 F_N ΔH shall be determined to be within the acceptable range:

a. Prior to operation above 75 percent of RATED THERMAL POWER after each fuel loading; and
b. At least once per 31 EFPD.

Surveillance Requirement 4.2.3.1.3 is being changed as follows:

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.

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 EFPD) is deleted because it is enveloped by the proposed Surveillance Requirement 4.2.3.1.3.b.

For the proposed deletion of "RCS total flow rate and" from SR 4.2.3.1.2, the licensee intends to make SR 4.2.3.1.2 for $F^N_{\Delta H}$ only and SR 4.2.3.1.3 for RCS flow rate only. This is an administrative change and, therefore, acceptable to the staff.

SR 4.2.3.1.3 is revised to make it applicable for RCS total flow rate which is verified by precision heat balance to be ≥ 363,200 gpm and greater than or equal to the limit specified in the Core Operating Limit Report (COLR). The licensee stated that 363,200 gpm is the RCS design flow corresponding to 10 percent SG plugging used in the updated uncertainty analysis for the stretch power uprate. The licensee stated that the measurement error of the RCS total flow is based upon performing a precision heat balance and using the results to calibrate the RCS flow rate indicators. To perform the precision heat balance, the instrumentation used for dtermination of steam pressure, feedwater pressure, feedwater temperature, and feedwater venturi ΔP in the calorimetric calculation are calibrated once per 18 months. The heat balance requires the plant to be at a minimum of 90 percent of the RTP to obtain the stated RTP flow accuracies. This surveillance is required to be performed within 24 hours after reaching 90

percent of the RTP following each fuel loading. Thus, to comply with the uncertainty analysis assumptions and to meet the heat balance requirements following each fuel loading, RCS flow shall be measured within 24 hours of RTP being equal to or grater than 90 percent RTP. As a result, it is unnecessary to require the RCS flow rate to be determined prior to operation above 75 percent of RTP after each fuel loading, which is specified in the current SR 4.2.3.1.2. Based on above considerations, the staff finds the proposed revision of SR 4.2.3.1.4 acceptable.

SR 4.2.3.1.4 reads as follows: “The RCS total flow rate indicators shall be subjected to a CHANNEL CALIBRATION at least once per 18 months. The measurement instrumentation shall be calibrated within 7 days prior to the performance of the calorimetric flow measurement.” As described above, the instrumentation calibrations required for heat balance are calibrated once per 18 months and within 7 days prior to performance of the calorimetric flow measurement. It is unnecessary to require the RCS flow measurement instrumentation to be calibrated within 7 days of the calorimetric flow measurement and because of that the NRC staff finds the proposed deletion of the last sentence to SR 4.2.3.1.4 acceptable.

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 7 days prior to the performance of the flow measurements. This requirement is deleted from the Technical Specifications.

As explained above, the requirement for RCS flow measurement instrumentation calibration within 7 days prior to performing heat balance is unnecessary and the 18 months calibration frequency for heat balance addressed in this SR is also addressed in the proposed SR 4.2.3.1.3. The staff finds deletion of SR 4.2.3.1.5 acceptable.

In addition, Surveillance Requirement 4.2.3.1.6 is proposed to be deleted. SR 4.2.3.1.6 currently reads, “If the feedwater venturis are not inspected at least once per 18 months, an additional 0.1% will be added to the total RCS measurement uncertainty.”

The licensee stated that 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. 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, the staff finds it acceptable to delete Surveillance Requirement 4.2.3.1.6.

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 AV (≥ 1897.6 psia) as that of the low pressurizer pressurereactor 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 SFP.

The licensee stated that this new P-19 permissive will be generated by the same two-out-of-four functional logic using same type of components under the same plant conditions as for the existing TS Table 2.2-1, functional unit 9, Pressurizer Pressure-Low instrumentation and is, therefore, selected to have the same values for the NTSP of 1900 psia, and AV ≥ 1897.6 psia. The NTSP for TS table 3.3-4, functional unit 1.d, Pressurizer Pressure Low SI is specified as 1892 psia, which is below the P-19 permissive. The licensee, also, stated that the low pressure SI uncertainty analysis shows that: (a) there is margin between the NTSP and the low pressurizer pressure SI Analytical Limit; (b) the SI and P-19 channel uncertainties are the same; and (c) the P-19 NTSP is established more conservative in relation to the low pressurizer pressure SI NTSP. Therefore, the P19 NTSP also has margin to the low pressurizer pressure SI analytical limit. The staff also concurs with the licensee that this functional unit being of permissive in nature is not safety limit-related.

The staff finds this change acceptable because it is consistent with the analyses evaluated in Section 2.8 of this SE.

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 RCS shrink and swell at SPU conditions.

The staff finds this change acceptable because the transient and accident analyses have been performed assuming the new pressurizer level control program, with acceptable methods, and acceptable results and meet GDCs 4, 10, and 12.

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 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).

The accident analysis requires that five MSSVs per SG to be operable to provide overpressure protection for design basis transients occurring at 102 percent RTP. The proposed TS maintain these criteria for modes 1, 2, 3.

As documented in Section 2.8 of this report, the maximum allowed power level with inoperable MSSVs has been re-calculated for SPU conditions. In order to preclude secondary side overpressurization in the event of a LOL or TT event, the maximum power level allowed for operation with inoperable MSSVs must be below the heat removing capability of the operable

MSSVs. The licensee recalculated the maximum power level for the revised limits at SPU conditions that accounts for a 9-percent uncertainty in the reactor trip setpoint. The limits specified in TS Table 3.7-1 were 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.

The Action Statements in TS 3.7.1 have also been revised to match the Improved Standard Technical Specifications; the TS completion times and actions proposed for MSSVs are consistent. The NRC staff considers the proposed TS requirements for the MSSV acceptable.

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 SFP.

The applicability for ACTIONs ‘d’ and ‘e’ will be “During Fuel movement within containment or the SFP.”

The staff finds this change is acceptable based on the staff review performed in Section 2.9 of this SE.

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.

The staff finds this change is acceptable based on the staff review performed in Section 2.3 of this SE.

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

The peak calculated containment internal pressure for the design-basis LOCA, Pa, is changed from 38.57 psig to 41.4 psig in TS 6.8.4.f.

The staff finds this change is acceptable based on the staff review performed in Section 2.6 of this SE.

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 LB LOCA methodology.

The staff finds this change is acceptable based on acceptable implementation of the referenced method, and acceptable analytical results, as discussed in Section 2.8 of this SE.

Additional Changes

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 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 BTP RSB 5-1, safety grade cold shutdown 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 CR, and within a reasonable period of time following shutdown. As discussed in MPS3 UFSAR Section 5.4.7.2.3.5, the MPS3 safety grade cold shutdown event is postulated to occur as a result of an SSE, coincident with a LOOP, and a safety-related electrical distribution system train failure. The train failure disables multiple safe shutdown components, including one RHR train. Thus, safety grade cold shutdown is a natural circulation RCS cooldown event. As defined in UFSAR 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 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.

The NRC staff reviewed this licensing basis change to MPS3 UFSAR Section 5.4.7.2.3.5 in Section 2.5 of the SE and the NRC staff finds it acceptable.

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*

As required in 10 CFR 50.48(a)(1), each operating nuclear plant must have a fire protection plan that satisfies GDC 3. MPS3 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 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 FPP. 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 DWST and CST usable inventory that allows for 38-hours of HOT STANDBY operation, followed by a 5-hour 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 BL NSID-TB-89-02 has advised against using seawater as a long-term 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, the licensee is proposing to modify the current fire shutdown strategy that relies upon service water (seawater) introduction into the SGs. Instead, the licensee 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 SG inventory make-up."

The NRC staff reviewed this licensing basis change to the DNC document entitled, "MP3 Branch Technical Position 9.5-1 Compliance Report," in Section 2.5 of the SE and the NRC staff finds this change acceptable.

3. *DWST Change*

The AFW system ensures a makeup water supply to the SG secondary side to support decay and sensible heat removal for the RCS. The AFW system is designed to mitigate many accidents including the LONF, FLB, SG 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 SBO, ATWS, SGCS, fire shutdown, and HELB mitigation.

The AFW system includes the DWST, which is the primary safety-related suction source for the AFW pumps. MPS3 UFSAR Section 10.4.9.1 and TSs 3/4.7.1.3 require a DWST inventory that is sufficient to maintain the RCS at HOT STANDBY condition for 10-hours with steam discharge to the atmosphere, concurrent with a total LOOP, 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 SBO 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 RCS at HOT STANDBY condition for 7-hours with steam discharged to the atmosphere, concurrent with a total LOOP, 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.

The licensee's application dated July 13, 2007, provided revised TS Bases pages to be implemented with the associated TS changes. The NRC staff reviewed this change in Section 2.5 of the SE and did not have any concerns.

4.0 REGULATORY COMMITMENTS

The licensee made no regulatory commitments.

5.0 RECOMMENDED AREAS FOR INSPECTION

Inspection Procedure (IP) 71004, "Power Uprates," describes the inspections necessary for power uprate related activities and provides guidance for the inspectors to use in conducting these inspections. As described above, the NRC staff has conducted an extensive review of the licensee's plans and analyses related to the proposed SPU and concluded that they are acceptable. The NRC staff's review has identified the following area for consideration by the NRC inspection staff during the licensee's implementation of the proposed SPU. These areas are recommended based on past experience with SPUs, the extent and unique nature of modifications necessary to implement the proposed SPU, and new conditions of operation necessary for the proposed SPU. They do not constitute inspection requirements.

- All EQ components located in the MSVB, most notably the NAMCo limit switches. If the NAMCo limit switches fail, inspect the other methods of monitoring valve position, the applicable procedures, and the operator training.

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Connecticut State official was notified of the proposed issuance of the amendment. The State official had no comments.

7.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, 51.32, 51.33, and 51.35, a draft Environmental Assessment and finding of no significant impact was prepared and published in the *Federal Register* on June 4, 4, 2008 (73 FR 31894). The draft Environmental Assessment provided a 30-day opportunity for public comment. No comments were received on the draft Environmental Assessment. The final Environmental Assessment was published in the *Federal Register* on August 7, 2008 (73 FR 46054). Accordingly, based upon the environmental assessment, the Commission has determined that the issuance of this amendment will not have a significant effect on the quality of the human environment.

8.0 FINAL NO SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

Background

The Commission issued a "Notice of Consideration of Issuance of Amendment to Facility Operating License, Proposed No Siginificant Hazards Consideration Determination and Opportunity for a Hearing" for the proposed MPS3 SPU amendment in the *Federal Register* on January 15, 2008 (73 FR 2549). This Notice provided 60 days for the public to request a hearing. A hearing on the license amendment was requested by Connecticut Coalition Against

Millstone (CCAM) and Nancy Burton on March 17, 2008.[184] The Atomic Safety and Licensing Board (ASLB) issued an Order dated June 4, 2008.[185] The ASLB Order denied CCAM and Nancy Burton's request for an evidentiary hearing. On June 16, 2008,[186] CCAM and Nancy Burton filed an appeal to the Commission regarding the ASLB Order.

The Commission's regulations in 10 CFR 50.91(a)(2)(i) state that:

> The Commission may publish in the *Federal Register* under §2.105 an individual notice of proposed action for an amendment for which it makes a proposed determination that no significant hazards consideration is involved...

Pursuant to 10 CFR 50.91(a)(2)(ii), the notice will contain the staff's proposed 10 CFR 50.92 determination, provide a brief description of the amendment and the facility involved, solicit public comments thereon, and provide for a 30-day comment period. The Commission issued a "Notice of Consideration of Issuance of Amendment to Facility Operating License, Proposed No Siginificant Hazards Consideration Determination and Opportunity for a Hearing" for the proposed MPS3 SPU amendment in the *Federal Register* on January 15, 2008 (73 FR 2549). There were no comments received.

Pursuant to 10 CFR 50.91(a)(3), the Commission does not publish a final determination on no significant hazards consideration, unless it receives a request for a hearing. A hearing on the license amendment was requested by CCAM and Nancy Burton on March 17, 2008. The ASLB Order denied CCAM and Nancy Burton's request for an evidentiary hearing. On June 16, 2008, CCAM and Nancy Burton filed an appeal to the Commission.

The Commission's regulations in 10 CFR 50.91(a)(4) state that:

> Where the Commission makes a final determination that no significant hazards consideration is involved and that the amendment should be issued, the amendment will be effective on issuance, even if adverse public comments have been received and even if an interested person meeting the provisions for intervention called for in §2.309 of this chapter has filed a request for a hearing. The Commission need hold any required hearing only after it issues an amendment, unless it determines that a significant hazards consideration is involved, in which case the Commission will provide an opportunity for a prior hearing.

The Commission's regulations in 10 CFR 50.92(c) state that the Commission may make a final determination that a proposed license amendment involves no significant hazards consideration (NSHC) if the operation of the facility in accordance with the proposed amendment would not:

(1) Involve a significant increase in the probability or consequences of an accident previously evaluated; or

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[184] ADAMS Accession No. ML080840527
[185] ADAMS Accession No. ML081560680
[186] ADAMS Accession No. ML081750222

(2) Create the possibility of a new or different kind of accident from any accident previously evaluated; or
(3) Involve a significant reduction in a margin of safety.

Pursuant to 10 CFR 50.91, the NRC staff made a proposed determination that the MPS3 SPU amendment request involves NSHC. A "Notice of Consideration of Issuance of Amendment to Facility Operating License, Proposed No Significant Hazards Consideration Determination and Opportunity for a Hearing" was issued in the *Federal Register* on January 15, 2008 (73 FR 2549). The notice provided a 30-day opportunity for public comment. The NRC staff did not receive comments on the proposed NSHC determination.

Final NSHC Determination

The NRC staff has completed its evaluation of the licensee's proposed SPU amendment as discussed in SE Section 2.0 above. Based on its evaluation, the staff has made a final determination that the proposed amendment does not involve a significant increase in the probability or consequences of an accident previously evaluated; does not create the possibility of a new or different kind of accident from any accident previously evaluated; and does not involve a significant reduction in a margin of safety. The following evaluation in relation to the three standards of 10 CFR 50.92(c) explains the staff's final NSHC determination.

First Standard

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

Response: No

As discussed in the licensee's application dated July 13, 2007, the MPS3 SPU analyses, which were performed at or above SPU conditions, included a review and evaluation of the structures, systems, and components (SSCs) that could be affected by the proposed change. The licensee reviewed plant modifications and revised operating parameters, including operator actions, to confirm acceptable performance of plant SSCs under SPU conditions. On this basis, the licensee concluded that there is no increase in the probability of accidents previously evaluated.

The NRC staff's evaluation of the proposed amendment included review of the SSCs that could be affected by the proposed change. This review included evaluation of plant modifications, revised operating parameters, changes to operator actions and procedures, and changes to the plant TSs. Based on this review, the staff concludes that there is reasonable assurance that the SSCs important to safety will continue to meet their intended design basis functions under SPU conditions. Therefore, the staff concludes that there is no significant change in the ability of these SSCs to preclude or mitigate the consequences of accidents.

The NRC staff's evaluation also reviewed the impact of the proposed SPU on the radiological consequences of design-basis accidents for MPS3. The staff's review concluded that dose criteria in 10 CFR 50.67, as well as the applicable acceptance criteria in Standard Review Plan Section 15.0.1, would continue to be met at SPU conditions.

The NRC staff concludes, based on review of the SSCs that could be affected by the proposed amendment and review of the radiological consequences, that the proposed amendment would not involve a significant increase in the consequences of an accident previously evaluated.

Based on the above, the NRC staff concludes that the proposed amendment would not involve a significant increase in the probability or consequences of an accident previously evaluated.

Second Standard

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

Response: No

As stated above, the NRC staff's evaluation of the proposed amendment included review of the SSCs that could be affected by the proposed change. This review included evaluation of plant modifications, revised operating parameters, changes to operator actions and procedures, and changes to the plant TSs. A failure modes and effect evaluation was performed by the licensee for the new ECCS permissive for the charging injection valves. This evaluation has shown that the change does not create any new failure modes that could lead to a different kind of accident. Based on this review, the staff concludes that the proposed amendment would not introduce any significantly different plant equipment, would not significantly impact the manner in which the plant is operated, and would not have any significant impact on the design function or operation of the SCCs involved. The staff's review did not identify any credible failure mechanisms, malfunctions, or accident initiators not already considered in the MPS3 design and licensing bases. Consequently, the staff concludes that the proposed change would not introduce any failure mode not previously analyzed.

Based on the above, the NRC staff concludes that the proposed change would not create the possibility of a new or different kind of accident from any accident previously evaluated.

Third Standard

Does the proposed amendment involve a significant reduction in a margin of safety?

Response: No

As discussed in the licensee's application, continuing improvements in analytical techniques based on a few decades of pressurized-water reactor safety technology, plant performance feedback, operating experience, and improved fuel and core designs, have resulted in a significant increase in the design and operating margin between the calculated safety analyses results and the current plant licensing limits. The NRC staff's review found that the proposed SPU will reduce some of the existing design and operational margins. However, safety margins are considered to not be significantly reduced if: (1) applicable regulatory requirements, codes and standards or their alternatives approved for use by the NRC, are met, and (2) if safety

analysis acceptance criteria in the licensing basis are met, or if proposed revisions to the licensing basis provide sufficient margin to account for analysis and data uncertainty. Margin of safety is related to confidence in the ability of the fission product barriers (i.e., fuel cladding, reactor coolant pressure boundary (RCPB), and containment) to limit the level of radiation dose to the public. The NRC staff evaluated the impact of the proposed SPU on the fission product barriers as discussed below.

The NRC staff evaluated the impact of the proposed SPU to assure that acceptable fuel damage limits are not exceeded. This included consideration of the MPS3 fuel system design, nuclear system design, thermal and hydraulic design, accident and transient analyses, and fuel design limits. The evaluation included an assessment of the margin in the associated safety analyses supporting the proposed SPU. The staff's evaluation found that the licensee's analysis was acceptable based on use of approved analytical methods and that the licensee had included sufficient margin to account for analysis and data uncertainty. In addition, the licensee will continue to perform cycle-specific analysis to confirm that fuel design limits will not be exceeded during each cycle. The staff's evaluation concluded that the applicable MPS3 licensing basis requirements would continue to be met following implementation of the proposed SPU. Therefore, the NRC staff concludes that fuel cladding integrity would be maintained within acceptable limits under the proposed SPU conditions.

The NRC staff further evaluated the impact of the proposed SPU on the RCPB. The evaluation included an assessment of overpressure protection; structural integrity of the RCPB piping, components, and supports; and structural integrity of the reactor vessel. With respect to overpressure protection, the staff found that the licensee had used the most limiting pressurization event and had determined that the peak calculated pressure would remain below the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) allowable peak pressure. With respect to structural integrity of the RCPB piping, the staff's evaluation concluded that RCPB structural integrity would be maintained at SPU conditions. With respect to structural integrity of the reactor vessel, the staff found that the licensee had used neutron fluence values acceptable for MPS3 at SPU conditions to calculate the upper shelf energy of the reactor vessel beltline materials. In addition, the staff found that the existing pressure-temperature limit curves contained in the TSs would remain bounding for SPU conditions. The staff also found that the the licensee evaluation of the loads on the reactor vessel was in accordance with the current plant ASME code of record and that the maximum stresses and fatigue usage factors for SPU conditions would be within ASME Code allowable limits. The staff's evaluation regarding the RCPB concluded that the applicable MPS3 licensing basis requirements would continue to be met following implementation of the proposed SPU. Therefore, the NRC staff concludes that RCPB structural integrity would be maintained under the proposed SPU conditions.

Finally, the NRC staff evaluated the impact of the proposed SPU on the containment. The staff found that the licensee's analysis used acceptable calculational methods and conservative assumptions and that the containment pressure and temperature under SPU conditions would remain below existing design limits. The staff's evaluation regarding the containment concluded that the applicable MPS3 licensing basis requirements would continue to be met following implementation of the proposed SPU. Therefore, the NRC staff concludes that containment structural integrity would be maintained under the proposed SPU conditions.

In summary, the NRC staff has concluded that the structural integrity of the fission product barriers (i.e., fuel cladding, RCPB and containment) would be maintained under SPU conditions. As such, the proposed amendment would not degrade confidence in the ability of the barriers to limit the level of radiation dose to the public.

Based on the above, the NRC staff concludes that the proposed change would not involve a significant reduction in a margin of safety.

Conclusion

On the basis of the above evaluation, the NRC staff has made a final determination that the proposed amendment does not involve a significant hazards consideration.

9.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) the amendment does not (a) involve a significant increase in the probability or consequences of an accident previously evaluated; or (b) create the possibility of a new or different kind of accident from any accident previously evaluated; or (c) involve a significant reduction in a margin of safety; (2) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner; (3) such activities will be conducted in compliance with the Commission's regulations; and (4) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

10.0 REFERENCES

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DNC letter (07-450B) to the NRC, “Dominion Nuclear Connecticut, Inc., Millstone Power Station Unit 3 Supplemental Information License Amendment Request, Stretch Power Uprate,” dated September 12, 2007, (ADAMS Accession No. ML072570061).

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DNC letter (07-0834C) to the NRC, “Dominion Nuclear Connecticut, Inc., Millstone Power Station Unit 3 Response to Request for Additional Information Regarding the Stretch Power Uprate License Amendment Request, Response to Questions EEEB-07-0049 and SCVB-07-0057”, dated January 10, 2008 (ADAMS Accession No. ML080100600).

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Attachment: List of Acronyms

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LIST OF ACRONYMS

AAC	alternate ac sources
AC	alternating current
ADBV	atmospheric dump block valve
ADVs	atmospheric dump valves
AF	As-found
AFW	Auxiliary feedwater
AFWS	auxiliary feedwater system
AL	As-left
ALARA	as low as reasonably achievable
AMP	aging monitoring program
AMSAC	ATWS mitigating system actuation circuitry
ANS	American Nuclear Society
AOOs	anticipated operational occurrences
AOPs	abnormal operating procedures
ARAVS	auxiliary and radwaste area ventilation system
ASME	American Society of Mechanical Engineers
ASTRUM	Automated Statistical Treatment of Uncertainty Method
ATWS	anticipated transient without scram
AV	allowable value
AVB	anti-vibration bars
B&PV	boiler and pressure vessel
B&W	Babcock and Wilcox
BE-LBLOCA	best-estimate large break LOCA
BL	bulletin
BLPBs	branch line pipe breaks
BOP	balance-of-plant

BRS	boron recovery system
BTP	branch technical position
CASS	Cast austenitic stainless steels
CBI	control building isolation
CCE	charging pumps cooling system
CCI	safety injection pumps cooling system
CCW	Component cooling water
CDF	core damage frequency
CDS	chilled water system
CE	Combustion Engineering
CEDE	committed effective dose equivalent
CREPS	control room envelope pressurization system
CREVS	control room emergency ventilation system
CFR	*Code of Federal Regulations*
CFS	condensate and feedwater system
CHF	critical heat flux
CLTP	current licensed thermal power
COLR	Core Operating Limit Report
CQD	Code Qualification Document
CR	Control room
CRAVS	control room area ventilation system
CRDM	control rod drive mechanism
CRDS	control rod drive system
CST	condensate storage tank
CSAU	Code Scaling Applicability and Uncertainty
CUF	cumulative usage factor
CVCS	chemical and volume control system
CWS	circulating water system

DBA	design-basis accident
DBLOCA	design-basis loss-of-coolant accident
DC	direct current
DCF	dose conversion factors
DE	double ended
DEHLB	double-ended hot leg break
DEI	dose equivalent iodine
DEPSB	double-ended pump suction break
DG	draft guide
DMIMS	digital metal impact monitoring system
DNB	departure from nucleate boiling
DNBR	departure from ducleate boiling ratio
DSS	diverse scram system
DWST	demineralized water storage tank
EAB	exclusion area boundary
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFDS	equipment and floor drainage system
EFPY	effective full-power year
EOL	end of life
EOP	emergency operating procedure
EPRI	Electric Power Research Institute
EPU	extended power uprate
EQ	environmental qualification
ESF	engineered safety feature
ESFAS	engineered safety feature actuation system
ESFVS	engineered safety feature ventilation system
FAC	flow-accelerated corrosion

FHA	fuel handling accident
FIV	flow-induced vibration
FLB	feedwater line break
FPP	fire protection program
GDC	general design criterion (or criteria)
GL	generic letter
GWMS	gaseous waste management system(s)
HFP	hot full power
HZP	hot zero power
I&C	instrumentation and controls
IASCC	irradiation-assisted stress corrosion cracking
ID	inside diameter
IN	information notice
IST	Inservice Testing
LAR	license amendment request
LBB	leak-before-break
LCO	limiting condition for operation
LLHS	light load handling system
LOL/TT	loss of load/turbine trip
LOCA	loss-of-coolant accident
LONF	loss of normal feedwater
LOOP	loss of offsite power
LPZ	low population zone
LR	Licensing Report
LRA	license renewal application
M&E	mass and energy
MC	Main condenser
MCES	main condenser evacuation system

MDF	mechanical design flow
MWD/MTU	megawatt-day/metric ton uranium
MOV	motor-operated valve
MPS3	Millstone Power Station, Unit 3
MSIV	main steam isolation valve
MSLB	main steamline break
MSS	main steam system
MSSS	main steam supply system
MSSV	Main steam safety valves
MTC	moderator temperature coefficient
MWt	megawatts thermal
NEI	Nuclear Energy Institute
NNS	non-nuclear safety
NPSH	net positive suction head
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
NRS	narrow range span
NSSS	nuclear steam supply system
NTSP	Nominal Trip Setpoint
O&M	operations and maintenance
OBE	operating-basis earthquake
OC	outside containment
OD	outside diameter
PASS	post accident sampling system
PB	pressure boundary
PC	partition coefficient
PCT	peak cladding temperature
P-T	pressure-temperature

PORV	power-operated relief valve
PRT	pressurizer relief tank
PSV	pressurizer safety valve
PTS	pressurized thermal shock
PWR	pressurized-water reactor
PWSCC	primary water stress-corrosion cracking
QSS	quench spray system
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RCCA	rod cluster control assembly or assemblies
RCL	reactor coolant loop
REA	rod ejection accident
RFA	robust fuel assembly
RFO	refueling outage
RG	regulatory guide
RHR	residual heat removal
RIA	reactivity insertion accident
rpms	revolutions per minute rpms
RPS	reactor protection system
RS	review standard
RSS	recirculation spray system
RSSTs	reserve station service transformers
RTDP	Revised Thermal Design Procedure
RTS	Reactor Trip system
RV	Reactor vessel
RWAP	Rod Withdrawal at Power
RWST	refueling water storage tank
SAFDL	specified acceptable fuel design limit

SAL	safety analysis limit
SAR	Safety Analysis Report
SBO	station blackout
SBLOCA	small-break LOCA
SDM	shutdown margin
SES	single-ended split
SFP	spent fuel pool
SFPAVS	spent fuel pool area ventilation system
SFPCCS	spent fuel pool cooling and cleanup system
SG	steam generator
SGBS	steam generator blowdown system
SGCS	steam generator cold shutdown
SGTR	steam generator tube rupture
SIs	stress intensities
SLB	small lines break
SLCRS	supplementary leak collection and release system
SPDS	Safety Parameter Display System
SPU	Stretch power uprate
SRP	Standard Review Plan
SS	Stainless steel
SSCs	structures, systems, and components
SSE	safe-shutdown earthquake
STD	Standard
STDP	Standard Thermal Design Procedure
SWMS	solid waste management system
SWS	service water system
TAVS	turbine area ventilation system
TBS	turbine bypass system

TCV	turbine control valve
TEDE	total effective dose equivalent
TGSS	turbine gland sealing system
TLAA	Time-limited aging analyses
TS	technical specification
TSC	Technical Service Center
TGSCC	transgranular stress corrosion cracking
UFSAR	Updated Final Safety Evaluation Report
UHS	ultimate heat sink
USE	Upper-shelf energy
UT	ultrasonic test