UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

December 22, 2011

Mr. Ken Langdon
Vice President Nine Mile Point
Nine Mile Point Nuclear Station, LLC
P.O. Box 63
Lycoming, NY 13093

SUBJECT: NINE MILE POINT NUCLEAR STATION, UNIT NO. 2 – ISSUANCE OF AMENDMENT RE: EXTENDED POWER UPRATE (TAC NO. ME1476)

Dear Mr. Langdon:

The Commission has issued the enclosed Amendment No. 140 to Facility Operating License No. NPF-69 for Nine Mile Point, Unit No. 2 (NMP2). This amendment consists of changes to the Renewed Facility Operating License and the Technical Specifications (TSs) in response to your application dated May 27, 2009,[1] as supplemented by additional letters.[2] The amendment increases the authorized maximum steady-state reactor core power level by approximately 15 percent, from the current licensed thermal power of 3,467 megawatts thermal (MWt) to 3,988 MWt.

The NRC has determined that the related safety evaluation (SE) contains proprietary information pursuant to Title 10 of the *Code of Federal Regulations*, Section 2.390, "Public Inspections, Exemptions, Requests for Withholding." Accordingly, the NRC staff has also prepared a redacted, publicly-available, non-proprietary version of the SE. Copies of the proprietary and non-proprietary versions of the SE are enclosed.

1 Agencywide Documents Access and Management System (ADAMS) Accession Package No. ML091610091
2 August 28, 2009 (ML092460610); December 23, 2009 (ML100190089); February 19, 2010 (ML100550598); April 16, 2010 (ML101120658); May 7, 2010 (ML101380306); June 3, 2010 (ML101610222); June 30, 2010 (ML101900471); July 9, 2010 (ML101950502); July 30, 2010 (ML102170191); September 16, 2010 (ML103050187); October 8, 2010 (ML102920339); October 28, 2010 (ML103080208); November 5, 2010 (ML103130515); December 10, 2010 (ML103500520); December 13, 2010 (ML103500363); January 19, 2011 (ML110250723); January 31, 2011 (ML110400373): February 4, 2011 (ML110460158); March 23, 2011 (ML110880300); May 9, 2011 (ML111370654); June 13, 2011 (ML111710135); July 15, 2011 (ML11207A069); August 5, 2011 (ML11207A069); August 19, 2011 (ML11242A044), September 23, 2011 (ML112700199); October 27, 2011 (ML113050319); and November 1, 2011 (ML113120336).

Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

RGuzman

Richard V. Guzman, Senior Project Manager
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-410

Enclosures:
1. Amendment No. 140 to License No. NPF-69
2. Non-Proprietary Safety Evaluation (ML113560333)
3. Proprietary Safety Evaluation (ML112930470)

cc w/o encl 3: Distribution via Listserv

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

NINE MILE POINT NUCLEAR STATION, LLC (NMPNS)

DOCKET NO. 50-410

NINE MILE POINT NUCLEAR STATION, UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 140
Renewed License No. NPF-69

1. The Nuclear Regulatory Commission (the Commission) has found that:

    A. The application for amendment by Nine Mile Point Nuclear Station, LLC (the licensee) dated May 27, 2009[1], as supplemented by additional letters[2], complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

    B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

    C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

    D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

    E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

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[1] Agencywide Documents Access and Management System (ADAMS) Accession Package No. ML091610091
[2] August 28, 2009 (ML092460610); December 23, 2009 (ML100190089); February 19, 2010 (ML100550598); April 16, 2010 (ML101120658); May 7, 2010 (ML101380306); June 3, 2010 (ML101610222); June 30, 2010 (ML101900471); July 9, 2010 (ML101950502); July 30, 2010 (ML102170191); October 8, 2010 (ML102920339); October 28, 2010 (ML103080208); November 5, 2010 (ML103130515); December 10, 2010 (ML103500520); December 13, 2010 (ML103500363); January 19, 2011 (ML110250723); January 31, 2011 (ML110400373): February 4, 2011 (ML110460158); March 23, 2011 (ML110880300); May 9, 2011 (ML111370654); June 13, 2011 (ML111710135); July 15, 2011 (ML11207A069); August 5, 2011 (ML11207A069); August 19, 2011 (ML11242A044); September 23, 2011 (ML112700199); October 27, 2011 (ML113050319); and November 1, 2011 (ML113120336).

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. NPF-69 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, as revised through Amendment No. 140 are hereby incorporated into this license. Nine Mile Point Nuclear Station, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan

   In addition, the license is amended to revise paragraph 2.C.(1) of Renewed Facility Operating License No. NPF-69 to reflect the new maximum licensed reactor core power level of 3988 megawatts thermal. The license is also amended to add new license conditions 2.C.(20) and (21) as follows:

   (20) Potential Adverse Flow Effects

   These license conditions provide for monitoring, evaluating, and taking prompt action in response to potential adverse flow effects as a result of power uprate operation on plant structures, systems, and components (including verifying the continued structural integrity of the steam dryer) for power ascension from current licensed thermal power (CLTP) (3467 MWt) to 120 percent original licensed thermal power (OLTP or 115 percent of CLTP) (3988 MWt) condition.

   (a) The following requirements are placed on operation of the facility above the thermal power level of 3467 MWt for the power ascension from CLTP (3467 MWt):

   1. NMPNS shall monitor the main steam line (MSL) strain gauges during power ascension above 3467 MWt for increasing pressure fluctuations in the steam lines. While first increasing power above 3467 MWt, NMPNS shall collect data from the MSL strain gauges at nominal 1 percent thermal power increments and evaluate steam dryer performance based on this data.

   2. NMPNS shall hold the facility at 105 percent and 110 percent of 3467 MWt to collect data from the MSL strain gauges required by Condition 1.a., conduct plant inspections and walkdowns, and evaluate steam dryer performance based on these data; shall provide the evaluation to the NRC staff by facsimile or electronic transmission to the NRC project manager upon completion of the evaluation; and shall not increase power above each hold point until 96 hours after the NRC project manager confirms receipt of the transmission.

   3. During power ascension at each 2.5 percent power level above CLTP, the licensee shall perform stress analysis for the top 100 stress locations of the steam dryer using the applicable ACM 4.1 load definition and determine the minimum alternating stress ratio. The licensee shall confirm that this ratio is equal to or greater than the ratio based on the velocity-square relationship;

otherwise, the licensee shall return the facility to a lower power level where the minimum alternating stress ratio satisfies the velocity-square relationship, and shall not further increase the power without approval from the NRC. A summary of the results shall be provided for NRC review at each 5 percent data review plateau. After completion of the full EPU test plateau (approximately 120 percent OLTP or 115 percent CLTP), the licensee shall provide the NRC a full startup test report and final stress analysis report within 90 days.

4. If any frequency peak from the MSL strain gauge data exceeds the Level 1 limit curves, NMPNS shall return the facility to a power level at which the limit curve is not exceeded. NMPNS shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation by facsimile or electronic transmission to the NRC project manager prior to further increases in reactor power, except when stress analysis is re-performed and new limit curves are developed. In that case, NMPNS shall not further increase power above each hold point until 96 hours after the NRC project manager confirms receipt of the transmission.

5. In addition to evaluating the MSL strain gauge data, NMPNS shall monitor reactor pressure vessel water level instrumentation, and MSL piping accelerometers on an hourly basis during power ascension above 3467 MWt. If resonance frequencies are identified as increasing above nominal levels in proportion to strain gauge instrumentation data, NMPNS shall stop power ascension, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to NRC staff by facsimile or electronic transmission to the NRC project manager prior to further increases in reactor power.

(b) NMPNS shall implement the following actions for the power ascension from CLTP (3467 MWt) to 120 percent OLTP (3988 MWt) condition.

1. In the event that acoustic signals (in MSL strain gauge signals) are identified that challenge the limit curves during power ascension above 3467 MWt, NMPNS shall evaluate dryer loads, and stresses, including the effect of ±10 percent frequency shift, and re-establish the limit curves, and shall perform a frequency-specific assessment of ACM uncertainty at the acoustic signal frequency including application of the ACM 4.0 values for percent bias error and for percent uncertainty to all the SRV acoustic resonances. In the event that stress analyses are re-performed based on new strain gauge data to address paragraph 1 above, the revised load definition, stress analysis, and limit curves shall include:

a. Application of the ACM 4.0 values for percent bias error and for percent uncertainty to all the SRV acoustic resonances.

b. Use of bump-up factors associated with all the SRV acoustic resonances and determined from the scale model test results.

c. Evaluation of the effect of ±10 percent frequency shifts in increments of 2.5 percent.

2. NMPNS shall incorporate in NMP2 steam dryer the design modifications identified in Section 2.2.6.1.2 of this SE before increasing the power above CLTP.

3. After reaching EPU conditions, NMPNS shall obtain measurements from the MSL strain gauges and establish the steam dryer flow-induced vibration load fatigue margin for the facility, update the dryer stress report, and re-establish the limit curves with the updated ACM load definition, which will be provided to the NRC staff.

4. NMPNS shall revise plant procedures to reflect long-term monitoring of plant parameters potentially indicative of steam dryer failure; to reflect consistency of the facility's steam dryer inspection program with BWRVIP-139; and to identify the NRC project manager for the facility as the point of contact for providing power ascension testing information during power ascension.

5. NMPNS shall submit the final EPU steam dryer load definition for the facility to the NRC upon completion of the power ascension test program.

6. NMPNS shall submit the flow-induced vibration related portions of the EPU startup test procedure to the NRC, including methodology for updating the limit curve, prior to initial power ascension above 3467 MWt.

(c) NMPNS shall prepare the EPU startup test procedure to include:

1. The stress limit curves to be applied for evaluating steam dryer performance;

2. Specific hold points and their durations during EPU power ascension;

3. Activities to be accomplished during the hold points;

4. Plant parameters to be monitored;

5. Inspections and walkdowns to be conducted for steam, feedwater, and condensate systems and components during the hold points;

6. Methods to be used to trend plant parameters;

7. Acceptance criteria for monitoring and trending plant parameters, and conducting the walkdowns and inspections;

8. Actions to be taken if acceptance criteria are not satisfied; and

9. Verification of the completion of commitments and planned actions specified in its application and all supplements to the application in support of the EPU license amendment request pertaining to the steam dryer prior to power increase above 3467 MWt.

NMPNS shall provide the related EPU startup test procedure sections to the NRC by facsimile or electronic transmission to the NRC project manager prior to increasing power above 3467 MWt.

(d) The following key attributes of the program for verifying the continued structural integrity of the steam dryer shall not be made less restrictive without prior NRC approval:

1. During initial power ascension testing above 3467 MWt, each test plateau increment shall be approximately 5 percent of 3467 MWt.

2. Level 1 performance criteria; and

3. The methodology for establishing the limit curves used for the Level 1 and Level 2 performance

(e) The results of the power ascension testing to verify the continued structural integrity of the steam dryer and the final steam dryer load definition shall be submitted to the NRC staff in a report within 60 days following the completion of all 120 percent OLTP (EPU) power ascension testing.

(f) During the first two scheduled refueling outages after reaching 120 percent OLTP conditions, a visual inspection shall be conducted of all accessible, susceptible locations of the steam dryer in accordance with BWRVIP-139 inspection guidelines. In addition, a visual inspection of all accessible welds that were analyzed using embedded models shall be conducted. In addition, a visual inspection of the existing indications in the upper support ring, the drain channel to skirt weld, the tie bar-to-hood weld heat affected zone, and vertical support plates shall be conducted.

(g) The results of the visual inspections of the steam dryer shall be reported to the NRC staff within 90 days following startup from the respective refueling outage.

(h) At the end of the second refueling outage, following the implementation of the EPU, the licensee shall submit a long-term steam dryer inspection plan based on industry operating experience along with the baseline inspection results for NRC review and approval.

The license conditions in 2.C.(20) above shall expire (1) upon satisfaction of the requirements in paragraphs (f) and (g), provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw(s) or unacceptable flaw growth that is due to fatigue, and (2) upon satisfaction of the requirements specified in paragraph (h).

(21) <u>Fatigue Monitoring Program</u>

If stress based fatigue monitoring is used, it shall include all six stress terms in accordance with NB-3200. The condition for this requirement will be carried over and be applicable for operation under EPU conditions and in the plant life extension to 60 years.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 90 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Eric J. Leeds, Director
Office of Nuclear Reactor Regulation

Attachment: Changes to the Operating License
and Technical Specifications

Date of Issuance: December 22, 2011

ATTACHMENT TO LICENSE AMENDMENT NO. 140

FACILITY OPERATING LICENSE NO. NPF-69

DOCKET NO. 50-410

Replace the following pages of the License with the attached revise pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
4	4
5	5
10	10
11	11
12	12
13	13
	14
	15
	16
	17

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove	Insert
1.1-5	1.1-5
2.0-1	2.0-1
3.1.7-3	3.1.7-3
3.2.1-1	3.2.1-1
3.2.2-1	3.2.2-1
3.2.3-1	3.2.3-1
3.3.1.1-2	3.3.1.1-2
3.3.1.1-4	3.3.1.1-4
3.3.1.1-6	3.3.1.1-6
3.3.1.1-8	3.3.1.1-8
3.3.1.1-9	3.3.1.1-9
3.3.1.1-10	3.3.1.1-10
3.3.2.2-1	3.3.2.2-1
3.3.2.2-2	3.3.2.2-2
3.3.4.1-1	3.3.4.1-1
3.3.4.1-2	3.3.4.1-2
3.3.4.1-3	3.3.4.1-3
3.3.6.1-6	3.3.6.1-6
3.4.3-2	3.4.3-2
3.7.5-1	3.7.5-1
4.0-2	4.0-2
4.0-3	4.0-3
4.0-4	4.0-4

(1) Maximum Power Level

Nine Mile Point Nuclear Station, LLC is authorized to operate the facility at reactor core power levels not in excess of 3988 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, as revised through Amendment No. 140 are hereby incorporated into this license. Nine Mile Point Nuclear Station, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Fuel Storage and Handling (Section 9.1, SSER 4)*

a. Fuel assemblies, when stored in their shipping containers, shall be stacked no more than three containers high.

b. When not in the reactor vessel, no more than three fuel assemblies shall be allowed outside of their shipping containers or storage racks in the New Fuel Vault or Spent Fuel Storage Facility.

c. The above three fuel assemblies shall maintain a minimum edge-to-edge spacing of twelve (12) inches from the shipping container array and approved storage rack locations.

d. The New Fuel Storage Vault shall have no more than ten fresh fuel assemblies uncovered at any one time.

(4) Turbine System Maintenance Program (Section 3.5.1.3.10, SER)

The operating licensee shall submit for NRC approval by October 31, 1989, a turbine system maintenance program based on the manufacturer's calculations of missile generation probabilities. (Submitted by NMPC letter dated October 30, 1989 from C.D. Terry and approved by NRC letter dated March 15, 1990 from Robert Martin to Mr. Lawrence Burkhardt, III).

* The parenthetical notation following the title of many license conditions denotes the section of the Safety Evaluation Report (SER) and/or its supplements wherein the license condition is discussed.

(5) Inservice Inspection (Sections 5.2.4.3 and 6.6.3, SSER 5)

The operating licensee shall submit an inservice inspection program in accordance with 10 CFR 50.55a(g)(4) for staff review by July 31, 1987.

(6) Initial Startup Test Program (Section 14, SER, SSERs 4 and 5)

Any changes to the Initial Test Program described in Section 14 of the Final Safety Analysis Report made in accordance with the provisions of 10 CFR 50.59 shall be reported in accordance with 50.59(b) within one month of such change.

(7) Operation with Reduced Feedwater Temperature (Section 15.1, SSER 4)

Nine Mile Point Nuclear Station, LLC shall not operate the facility with reduced feedwater temperature for the purpose of extending the normal fuel cycle. The facility shall not be operated with a feedwater heating capacity less than that required to produce a feedwater temperature of 420.5 °F at rated steady-state conditions unless analyses supporting such operations are submitted by Nine Mile Point Nuclear Station, LLC and approved by the staff.

(8) Safety Parameter Display System (SPDS) (Section 18.2, SSERs 3 and 5)

Prior to startup following the first refueling outage, the operating licensee shall have operational an SPDS that includes the revisions described in their letter of November 19, 1985. Before declaring the SPDS operational, the operating licensee shall complete testing adequate to ensure that no safety concerns exist regarding the operation of the Nine Mile Point Nuclear Station, Unit No. 2 SPDS.

(9) Detailed Control Room Design Review (Section 18.1, SSERs 5 and 6)

(a) Deleted per Amendment No. 24 (12-18-90)

(b) Prior to startup following the first refueling outage, the operating licensee shall provide the results of the reevaluation of normally lit and nuisance alarms for NRC review in accordance with its August 21, 1986 letter.

(c) Prior to startup following the first refueling outage, the operating licensee shall complete permanent zone banding of meters in accordance with its August 4, 1986 letter.

(20) Potential Adverse Flow Effects

These license conditions provide for monitoring, evaluating, and taking prompt action in response to potential adverse flow effects as a result of power uprate operation on plant structures, systems, and components (including verifying the continued structural integrity of the steam dryer) for power ascension from CLTP (3467 MWt) to 120 percent OLTP (or 115 percent of CLTP) (3988 MWt) condition.

(a) The following requirements are placed on operation of the facility above the thermal power level of 3467 MWt for the power ascension from CLTP (3467 MWt):

1. NMPNS shall monitor the main steam line (MSL) strain gages during power ascension above 3467 MWt for increasing pressure fluctuations in the steam lines. While first increasing power above 3467 MWt, NMPNS shall collect data from the MSL strain gages at nominal 1 percent thermal power increments and evaluate steam dryer performance based on this data.

2. NMPNS shall hold the facility at 105 percent and 110 percent of 3467 MWt to collect data from the MSL strain gages required by Condition 1.a., conduct plant inspections and walkdowns, and evaluate steam dryer performance based on these data; shall provide the evaluation to the NRC staff by facsimile or electronic transmission to the NRC project manager upon completion of the evaluation; and shall not increase power above each hold point until 96 hours after the NRC project manager confirms receipt of the transmission.

3. During power ascension at each 2.5 percent power level above CLTP, the licensee shall perform stress analysis for the top 100 stress locations of the steam dryer using the applicable ACM 4.1 load definition and determine the minimum alternating stress ratio. The licensee shall confirm that this ratio is equal to or greater than the ratio based on the velocity-square relationship; otherwise, the licensee shall return the facility to a lower power level where the minimum alternating stress ratio satisfies the velocity-square relationship, and shall not further increase the power without approval from the NRC. A summary of the results shall be provided for NRC review at each 5 percent data review plateau. After completion of the full EPU test plateau (approximately 120 percent OLTP or 115 percent CLTP), the licensee shall provide the NRC a full startup test report and final stress analysis report within 90 days.

4. If any frequency peak from the MSL strain gage data exceeds the Level 1 limit curves, NMPNS shall return the facility to a power level at which the limit curve is not exceeded. NMPNS shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation by facsimile or electronic transmission to the NRC project manager prior to further increases in

reactor power, except when stress analysis is re-performed and new limit curves are developed. In that case, NMPNS shall not further increase power above each hold point until 96 hours after the NRC project manager confirms receipt of the transmission.

5. In addition to evaluating the MSL strain gage data, NMPNS shall monitor reactor pressure vessel water level instrumentation, and MSL piping accelerometers on an hourly basis during power ascension above 3467 MWt. If resonance frequencies are identified as increasing above nominal levels in proportion to strain gage instrumentation data, NMPNS shall stop power ascension, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to NRC staff by facsimile or electronic transmission to the NRC project manager prior to further increases in reactor power.

(b) NMPNS shall implement the following actions for the power ascension from CLTP (3467 MWt) to 120 percent OLTP (3988 MWt) condition.

1. In the event that acoustic signals (in MSL strain gage signals) are identified that challenge the limit curves during power ascension above 3467 MWt, NMPNS shall evaluate dryer loads, and stresses, including the effect of ±10 percent frequency shift, and re-establish the limit curves, and shall perform a frequency-specific assessment of ACM uncertainty at the acoustic signal frequency including application of 65 percent bias error and 10 percent uncertainty to all the SRV acoustic resonances. In the event that stress analyses are re-performed based on new strain gage data to address paragraph 1 above, the revised load definition, stress analysis, and limit curves shall include:

   (a) Application of 65 percent bias error and 10 percent uncertainty to all the SRV acoustic resonances.
   (b) Use of bump-up factors associated with all the SRV acoustic resonances and determined from the scale model test results.
   (c) Evaluation of the effect of ±10 percent frequency shifts in increments of 2.5 percent.

2. NMPNS shall incorporate in NMP2 steam dryer the design modifications identified in Section 2.2.6.1.2 of this SE before increasing the power above CLTP.

3. After reaching EPU conditions, NMPNS shall obtain measurements from the MSL strain gages and establish the steam dryer flow-induced vibration load fatigue margin for the facility, update the dryer stress report, and re-establish the limit curves with the updated ACM load definition, which will be provided to the NRC staff.

4. NMPNS shall revise plant procedures to reflect long-term monitoring of plant parameters potentially indicative of steam dryer failure; to reflect consistency of the facility's steam dryer inspection program with BWRVIP-139; and to identify the NRC project manager for the facility as the point of contact for providing power ascension testing information during power ascension.

5. NMPNS shall submit the final EPU steam dryer load definition for the facility to the NRC upon completion of the power ascension test program.

6. NMPNS shall submit the flow-induced vibration related portions of the EPU startup test procedure to the NRC, including methodology for updating the limit curve, prior to initial power ascension above 3467 MWt.

(c) NMPNS shall prepare the EPU startup test procedure to include:

1. The stress limit curves to be applied for evaluating steam dryer performance;

2. Specific hold points and their durations during EPU power ascension;

3. Activities to be accomplished during the hold points;

4. Plant parameters to be monitored;

5. Inspections and walkdowns to be conducted for steam, feedwater, and condensate systems and components during the hold points;

6. Methods to be used to trend plant parameters;

7. Acceptance criteria for monitoring and trending plant parameters, and conducting the walkdowns and inspections;

8. Actions to be taken if acceptance criteria are not satisfied; and

9. Verification of the completion of commitments and planned actions specified in its application and all supplements to the application in support of the EPU license amendment request pertaining to the steam dryer prior to power increase above 3467 MWt.

NMPNS shall provide the related EPU startup test procedure sections to the NRC by facsimile or electronic transmission to the NRC project manager prior to increasing power above 3467 MWt.

(d) The following key attributes of the program for verifying the continued structural integrity of the steam dryer shall not be made less restrictive without prior NRC approval:

1. During initial power ascension testing above 3467 MWt, each test plateau increment shall be approximately 5 percent of 3467 MWt.

2. Level 1 performance criteria; and

3. The methodology for establishing the limit curves used for the Level 1 and Level 2 performance

(e) The results of the power ascension testing to verify the continued structural integrity of the steam dryer and the final steam dryer load definition shall be submitted to the NRC staff in a report within 60 days following the completion of all 120 percent OLTP (EPU) power ascension testing.

(f) During the first two scheduled refueling outages after reaching 120 percent OLTP conditions, a visual inspection shall be conducted of all accessible, susceptible locations of the steam dryer in accordance with BWRVIP-139 inspection guidelines. In addition, a visual inspection of all accessible welds that were analyzed using embedded models shall be conducted. In addition, a visual inspection of the existing indications in the upper support ring, the drain channel to skirt weld, the tie bar-to-hood weld heat affected zone, and vertical support plates shall be conducted.

(g) The results of the visual inspections of the steam dryer shall be reported to the NRC staff within 90 days following startup from the respective refueling outage.

(h) At the end of the second refueling outage, following the implementation of the EPU, the licensee shall submit a long-term steam dryer inspection plan based on industry operating experience along with the baseline inspection results for NRC review and approval.

The license conditions in 2.C.(20) above shall expire (1) upon satisfaction of the requirements in paragraphs (f) and (g), provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw(s) or unacceptable flaw growth that is due to fatigue, and (2) upon satisfaction of the requirements specified in paragraph (h).

(21) <u>Fatigue Monitoring Program</u>

If stress based fatigue monitoring is used, it shall include all six stress terms in accordance with NB-3200. The condition for this requirement will be carried over and be applicable for operation under EPU conditions and in the plant life extension to 60 years.

D. The facility requires exemptions from certain requirements of 10 CFR Part 50 and 10 CFR Part 70.

i) An exemption from the critically alarm requirements of 10 CFR Part 70.24 was granted in the Special Nuclear Materials License No. SNM-1895 dated November 27, 1985. This exemption is described in Section 9.1 of Supplement 4 to the SER. This previously granted exemption is continued in this operating license.

ii) Exemptions to certain requirements of Appendix J to 10 CFR Part 50 are described in Supplements 3, 4, and 5 to the SER. These include (a) (this item left intentionally blank); (b) an exemption from the requirement of Option B of Appendix J, exempting main steam isolation valve measured leakage from the combined leakage rate limit of 0.6 La. (Section 6.2.6 of SSER 5)*; (c) an exemption from Option B of Appendix J, exempting the hydraulic control system for the reactor recirculation flow control valves from Type A and Type C leak testing (Section 6.2.6 of SSER 3); (d) an exemption from Option B of Appendix J, exempting Type C testing on traversing incore probe system shear valves. (Section 6.2.6 SSER 4)

iii) An exemption to Appendix A to 10 CFR Part 50 exempting the Control Rod Drive (CRD) hydraulic lines to the reactor recirculation pump seal purge equipment from General Design Criterion (GDC) 55. The CRD hydraulic lines to the reactor recirculation pump seal purge equipment use two simple check valves for the isolation outside containment (one side). (Section 6.2.4, SSER 3)

iv) A schedular exemption to GDC 2, Appendix A to 10 CFR Part 50, until the first refueling outage, to demonstrate the adequacy of the downcomer design under the plant faulted condition. This exemption permits additional analysis and/or modifications, as necessary, to be completed by the end of the first refueling outage. (Section 6.2.1.7.4, SSER 3)

v) A schedular exemption to GDC 50, Appendix A to 10 CFR Part 50 to allow the operating licensee until start-up following the "mini-outage," which is to occur within 12 months of commencing power operation (entering Operational Condition 1), to install redundant fuses in circuits that use transformers for redundant penetration protection in accordance with their letter of August 29, 1986 (NMP2L 0860). (Section 8.4.2, SSER 5)

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* The parenthetical notation following the discussion of each exemption denotes the section of the Safety Evaluation Report (SER) and/or its supplements wherein the safety evaluation of the exemption is discussed.

vi) A schedular exemption to 10 CFR 50.55a(h) for the Neutron Monitoring System until completion of the first refueling outage to allow the operating licensee to provide qualified isolation devices for Class 1E/non-1E interfaces described in their letters of June 23, 1987 (NMP2L 1057) and June 25, 1987 (NMP2L 1058). (Section 7.2.2.10, SSER 6).

For the schedular exemptions in iv), v), and vi), above, the operating licensee, in accordance with its letter of October 31, 1986, shall certify that all systems, components, and modifications have been completed to meet the requirements of the regulations for which the exemptions have been granted and shall provide a summary description of actions taken to ensure that the regulations have been met. This certification and summary shall be provided 10 days prior to the expiration of each exemption period as described above.

The exemptions set forth in this Section 2.D are authorized by law, will not present an undue risk to public health and safety, and are consistent with the common defense and security. These exemptions are hereby granted. The special circumstances regarding each exemption are identified in the referenced section of the Safety Evaluation Report and the supplements thereto. The exemptions in ii) through vi) are granted pursuant to 10 CFR 50.12.

With these exemptions, the facility will operate to the extent authorized herein, in conformity with the application, as amended, the provisions of the Act, and the rules and regulations of the Commission.

E. Nine Mile Point Nuclear Station, LLC shall fully implement and maintain in effect all provisions of the Commission-approved physical security, training and qualification, and safeguards contingency plans, including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The combined set of plans, which contain Safeguards Information protected under 10 CFR 73.21 is entitled "Nine Mile Point Nuclear Station, LLC Physical Security, Safeguards Contingency, and Security Training and Qualification Plan, Revision 1," and was submitted by letter dated April 26, 2006. Changes made in accordance with 10 CFR 73.55 shall be implemented in accordance with the schedule set forth therein.

F. Nine Mile Point Nuclear Station, LLC shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report for the facility through Amendment No. 27 and as described in submittals dated March 25, May 7 and 9, June 10 and 25, July 11 and 16, August 19 and 22, September 5, 12, and 23, October 10, 21, and 22, and December 9, 1986, and April 10 and May 20, 1987, and as approved in the SER dated February 1985 (and Supplements 1 through 6) subject to the following provision:

Nine Mile Point Nuclear Station, LLC may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire.

G. The licensees shall have and maintain financial protection of such type and in such amounts as the Commission shall require in accordance with Section 170 of the Atomic Energy Act of 1954, as amended, to cover public liability claims.

H. This license is effective as of the date of issuance and shall expire at midnight on October 31, 2046.

I. The UFSAR supplement, as revised, submitted pursuant to 10 CFR 54.21(d), shall be included in the next scheduled update to the USAR required by 10 CFR 50.71(e)(4) following the issuance of this renewed operating license. Until that update is complete, NMP LLC may make changes to the programs and activities described in the supplement without prior Commission approval, provided that NMP LLC evaluates such changes pursuant to the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

J. The UFSAR supplement, as revised, describes certain future activities to be completed prior to the period of extended operation. NMP LLC shall complete these activities in accordance with Appendix A of NUREG-1900, "Safety Evaluation Report Related to the License Renewal of Nine Mile Point Nuclear Station, Units 1 and 2", dated September 2006, and shall notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection.

K. For the renewed license term, all capsules in the reactor vessel that are removed and tested must meet the test procedures and reporting requirements of the most recent NRC-approved version of the Boiling Water Reactor Vessels and Internals Project (BWRVIP) Integrated Surveillance Program (ISP) appropriate for the configuration of the specimens in the capsule. All capsules placed in storage must be maintained for future insertion. Any changes to storage requirements must be approved by the NRC, as required by 10 CFR Part 50, Appendix H.

FOR THE NUCLEAR REGULATORY COMMISSION

Original Signed by

J. E. Dyer, Director
Office of Nuclear Reactor Regulation

Enclosures:
1. Appendix A – Technical Specifications (NUREG-1253)
2. Appendix B – Environmental Protection Plan

Date of Issuance: October 31, 2006

1.1 Definitions (continued)

MODE

A MODE shall correspond to any one inclusive combination of mode switch position, average reactor coolant temperature, and reactor vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.

OPERABLE – OPERABILITY

A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).

PHYSICS TESTS

PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are:

a. Described in Chapter 14, Initial Test Program of the FSAR;

b. Authorized under the provisions of 10 CFR 50.59; or

c. Otherwise approved by the Nuclear Regulatory Commission.

RATED THERMAL POWER (RTP)

RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3988 MWt.

REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME

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

(continued)

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

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

THERMAL POWER shall be ≤ 23% RTP.

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

MCPR shall be ≥ 1.07 for two recirculation loop operation or ≥ 1.09 for single recirculation loop operation.

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

2.1.2 Reactor Coolant System Pressure SL

Reactor steam dome pressure shall be ≤ 1325 psig.

2.2 SL Violations

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

2.2.1 Restore compliance with all SLs; and

2.2.2 Insert all insertable control rods.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.7.7	Verify each pump develops a flow rate $\geq$ 41.2 gpm at a discharge pressure $\geq$ 1327 psig.	In accordance with the Inservice Testing Program
SR 3.1.7.8	Verify flow through one SLC subsystem from pump into reactor pressure vessel.	24 months on a STAGGERED TEST BASIS
SR 3.1.7.9	Verify all heat traced piping between storage tank and pump suction valve is unblocked.	24 months <u>AND</u> Once within 24 hours after piping temperature is restored to $\geq$ 70°F
SR 3.1.7.10	Verify sodium pentaborate enrichment is $\geq$ 25 atom percent B-10.	Prior to addition to SLC tank

3.2 POWER DISTRIBUTION LIMITS

3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

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

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any APLHGR not within limits.	A.1 Restore APLHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.1.1	Verify all APLHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 23% RTP AND 24 hours thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

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

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any MCPR not within limits.	A.1 Restore MCPR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify all MCPRs are greater than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 23% RTP <u>AND</u> 24 hours thereafter

(continued)

3.2 POWER DISTRIBUTION LIMITS

3.2.3 LINEAR HEAT GENERATION RATE (LHGR)

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

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Any LHGR not within limits.	A.1 Restore LHGR(s) to within limits.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.3.1	Verify all LHGRs are less than or equal to the limits specified in the COLR.	Once within 12 hours after ≥ 23% RTP <u>AND</u> 24 hours thereafter

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more Functions with RPS trip capability not maintained.	C.1 Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1 Reduce THERMAL POWER to < 26% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1 Initiate alternate method to detect and suppress thermal-hydraulic instability oscillations. <u>AND</u> F.2 Restore required channel to OPERABLE status.	12 hours 120 days
G. Required Action and associated Completion Time of Condition F not met. <u>OR</u> As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1 Be in MODE 2.	6 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.3	-------------------------NOTE------------------------- Not required to be performed until 12 hours after THERMAL POWER $\geq$ 23% RTP. -- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power $\leq$ 2% RTP while operating at $\geq$ 23% RTP.	7 days
SR 3.3.1.1.4	-------------------------NOTE------------------------- For Functions 1.a and 1.b, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. -- Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.5	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to fully withdrawing SRMs
SR 3.3.1.1.6	-------------------------NOTE------------------------- Only required to be met during entry into MODE 2 from MODE 1. -- Verify the IRM and APRM channels overlap.	7days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.13	----------NOTES---------- 1. Neutron detectors are excluded. 2. For Functions 1.a and 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. 3. For Function 2.e, the CHANNEL CALIBRATION only requires a verification of ORRM-Upscale setpoints in the APRM by the review of the "Show Parameters" display. ------------------------- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.1.14	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.15	Verify Turbine Stop Valve – Closure, and Turbine Control Valve Fast Closure, Trip Oil Pressure – Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	24 months
SR 3.3.1.1.16	Verify APRM OPRM-Upscale Function is not bypassed when THERMAL POWER is ≥ 26% RTP and recirculation drive flow is < 60% of rated recirculation drive flow.	24 months

(continued)

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux — Upscale	2	3	H	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.5 SR 3.3.1.1.6 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 122/125 divisions of full scale
	5(a)	3	I	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 122/125 divisions of full scale
b. Inop	2	3	H	SR 3.3.1.1.4 SR 3.3.1.1.14	NA
	5(a)	3	I	SR 3.3.1.1.4 SR 3.3.1.1.14	NA
2. Average Power Range Monitors					
a. Neutron Flux – Upscale, Setdown	2	3 per logic channel	H	SR 3.3.1.1.2 SR 3.3.1.1.6 SR 3.3.1.1.7 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 20% RTP
b. Flow Biased Simulated Thermal Power – Upscale	1	3 per logic channel	G	SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.7 SR 3.3.1.1.10 SR 3.3.1.1.13(c),(d)	≤ .55W + 60.5% RTP and ≤ 115.5% RTP(b)
c. Fixed Neutron Flux – Upscale	1	3 per logic channel	G	SR 3.3.1.1.2 SR 3.3.1.1.3 SR 3.3.1.1.7 SR 3.3.1.1.10 SR 3.3.1.1.13	≤ 120% RTP
d. Inop	1,2	3 per logic channel	H	SR 3.3.1.1.7 SR 3.3.1.1.10	NA
e. OPRM-Upscale	1	3 per logic channel	F	SR 3.3.1.1.2 SR 3.3.1.1.7 SR 3.3.1.1.10 SR 3.3.1.1.13 SR 3.3.1.1.16	As specified in the COLR
f. 2-Out-Of-4 Voter	1,2	2	H	SR 3.3.1.1.2 SR 3.3.1.1.10 SR 3.3.1.1.14 SR 3.3.1.1.17	NA

(continued)

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

(b) Allowable Value is .50(W - 5%) + 53.5% RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating."

(c) If the As-Found channel setpoint is outside its predefined As-Found tolerances, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(d) The instrument channel setpoint shall be reset to a value within the As-Left tolerance around the nominal trip setpoint at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the nominal trip setpoint are acceptable provided that the As-Found and As-Left tolerances apply to the actual setpoint implemented in the surveillance procedures to confirm channel performance. The nominal trip setpoint and the methodologies used to determine the As-Found and the As-Left tolerances are specified in the Bases associated with the specified function.

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. Reactor Vessel Steam Dome Pressure – High	1,2	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.17	≤ 1072 psig
4. Reactor Vessel Water Level – Low, Level 3	1,2	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.17	≥ 157.8 inches
5. Main Steam Isolation Valve – Closure	1	8	G	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.17	≤ 12% closed
6. Drywell Pressure – High	1,2	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 1.88 psig
7. Scram Discharge Volume Water Level – High					
a. Transmitter/Trip Unit	1,2	2	H	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.11 SR 3.3.1.1.14	≤ 49.5 inches
	5[(a)]	2	I	SR 3.3.1.1.1 SR 3.3.1.1.8 SR 3.3.1.1.9 SR 3.3.1.1.11 SR 3.3.1.1.14	≤ 49.5 inches
b. Float Switch	1,2	2	H	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 49.5 inches
	5[(a)]	2	I	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14	≤ 49.5 inches
8. Turbine Stop Valve – Closure	≥ 26% RTP	4	E	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.17	≤ 7% closed

(continued)

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

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
9. Turbine Control Valve Fast Closure, Trip Oil Pressure – Low	≥ 26% RTP	2	E	SR 3.3.1.1.8 SR 3.3.1.1.13 SR 3.3.1.1.14 SR 3.3.1.1.15 SR 3.3.1.1.17	≥ 465 psig
10. Reactor Mode Switch – Shutdown Position	1,2	2	H	SR 3.3.1.1.12 SR 3.3.1.1.14	NA
	5(a)	2	I	SR 3.3.1.1.12 SR 3.3.1.1.14	NA
11. Manual Scram	1,2	4	H	SR 3.3.1.1.4 SR 3.3.1.1.14	NA
	5(a)	4	I	SR 3.3.1.1.4 SR 3.3.1.1.14	NA

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

3.3 INSTRUMENTATION

3.3.2.2 Feedwater System and Main Turbine High Water Level Trip Instrumentation

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

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One feedwater system and main turbine high water level trip channel inoperable.	A.1 Place channel in trip.	7 days
B. Two or more feedwater system and main turbine high water level trip channels inoperable.	B.1 Restore feedwater system and main turbine high water level trip capability.	2 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1	--------------NOTE-------------- Only applicable if inoperable channel is the result of an inoperable feedwater pump breaker. ----------------------------------	
		Remove affected feedwater pump(s) from service.	4 hours
	OR		
	C.2	Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

-- NOTE --
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided feedwater system and main turbine high water level trip capability is maintained.

SURVEILLANCE		FREQUENCY
SR 3.3.2.2.1	Perform CHANNEL CHECK.	24 hours
SR 3.3.2.2.2	Perform CHANNEL FUNCTIONAL TEST.	92 days

(continued)

3.3 INSTRUMENTATION

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

LCO 3.3.4.1

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

1. Turbine Stop Valve (TSV) – Closure; and

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

<u>OR</u>

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

APPLICABILITY: THERMAL POWER $\geq$ 26% RTP with any recirculation pump in fast speed.

ACTIONS

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

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	------------NOTE------------ Not applicable if inoperable channel is the result of an inoperable breaker. ------------------------------- Place channel in trip.	72 hours
B. One or more Functions with EOC-RPT trip capability not maintained. <u>AND</u> MCPR limit for inoperable EOC-RPT not made applicable.	B.1	Restore EOC-RPT trip capability.	2 hours
	<u>OR</u>		
	B.2	Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	2 hours
C. Required Action and associated Completion Time not met.	C.1	Remove the associated recirculation pump fast speed breaker from service.	4 hours
	<u>OR</u>		
	C.2	Reduce THERMAL POWER to < 26% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

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

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.1	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.4.1.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. TSV – Closure: ≤ 7% closed; and b. TCV Fast Closure, Trip Oil Pressure – Low: ≥ 465 psig.	24 months
SR 3.3.4.1.3	Perform LOGIC SYSTEM FUNCTIONAL TEST, including breaker actuation.	24 months
SR 3.3.4.1.4	Verify TSV – Closure and TCV Fast Closure, Trip Oil Pressure – Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	24 months
SR 3.3.4.1.5	----- NOTE ----- Breaker arc suppression time may be assumed from the most recent performance of SR 3.3.4.1.6. ----- Verify the EOC-RPT SYSTEM RESPONSE TIME is within limits.	24 months on a STAGGERED TEST BASIS

(continued)

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Main Steam Line Isolation					
a. Reactor Vessel Water Level – Low Low Low, Level 1	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.5 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ 10.8 inches
b. Main Steam Line Pressure – Low	1	2	E	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.5 SR 3.3.6.1.6 SR 3.3.6.1.7	≥ 746 psig
c. Main Steam Line Flow – High	1,2,3	2 per MSL	D	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.5 SR 3.3.6.1.6 SR 3.3.6.1.7	≤ 184.4 psid
d. Condenser Vacuum – Low	1,2(a), 3(a)	2	D	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.4 SR 3.3.6.1.5 SR 3.3.6.1.6	≥ 7.6 inches Hg vacuum
e. Main Steam Line Tunnel Temperature – High	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 170.6°F
f. Main Steam Line Tunnel Differential Temperature – High	1,2,3	2	D	SR 3.3.6.1.1 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 71.7°F
g. Main Steam Line Tunnel Lead Enclosure Temperature – High	1,2,3	2 per area	D	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5 SR 3.3.6.1.6	≤ 151.6°F(b)
h. Manual Initiation	1,2,3	4	G	SR 3.3.6.1.6	NA

(continued)

(a) With any turbine stop valve not closed.

(b) 151.6°F + (0.6)(T_{amb} - 90°F) and ≤ 175.6°F provided the absence of steam leaks in the main steam line tunnel lead enclosure area is verified by visual inspection prior to establishing the Allowable Value.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	-------------------------------NOTES--------------------------- 1. Not required to be performed until 4 hours after associated recirculation loop is in operation. 2. Not required to be performed until 24 hours after > 23% RTP. --- Verify at least two of the following criteria (a, b, and c) are satisfied for each operating recirculation loop: a. Jet pump loop flow versus flow control valve position differs by ≤ 10% from established patterns. b. Jet pump loop flow versus recirculation loop drive flow differs by ≤ 10% from established patterns. c. Each jet pump diffuser to lower plenum differential pressure differs by ≤ 20% from established patterns.	24 hours

3.7 PLANT SYSTEMS

3.7.5 Main Turbine Bypass System

LCO 3.7.5 The Main Turbine Bypass System shall be OPERABLE.

<u>OR</u>

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

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	Perform a system functional test.	24 months
SR 3.7.5.2	Verify the TURBINE BYPASS SYSTEM RESPONSE TIME is within limits.	24 months

4.0 DESIGN FEATURES (continued)

4.3 Fuel Storage

4.3.1 Criticality

4.3.1.1 The spent fuel storage racks are designed and shall be maintained with:

a. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 9.1.2 of the USAR;

b. A nominal 6.18 inch center to center distance between fuel assemblies placed in the storage racks;

c. Fuel assemblies having a maximum k-infinity of 1.32 in the normal reactor core configuration at cold conditions; and

d. Fuel assemblies having a maximum U-235 enrichment of 4.9 weight percent.

4.3.1.2 The new fuel storage racks are designed and shall be maintained with:

a. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 9.1.1 of the USAR;

b. $k_{eff} \leq 0.98$ with all but one of the non-combustible storage vaults covers in place when optimum moderation (foam, spray, fogging, or small droplets) is assumed;

c. A nominal 7.00 inch center to center distance between fuel assemblies placed within a storage rack and a nominal 12.25 inch center to center distance between fuel assemblies in adjacent racks;

d. Fuel assemblies having a maximum k-infinity of 1.34 in the normal reactor core configuration at cold conditions; and

e. Fuel assemblies having a maximum U-235 enrichment of 4.9 weight percent.

(continued)

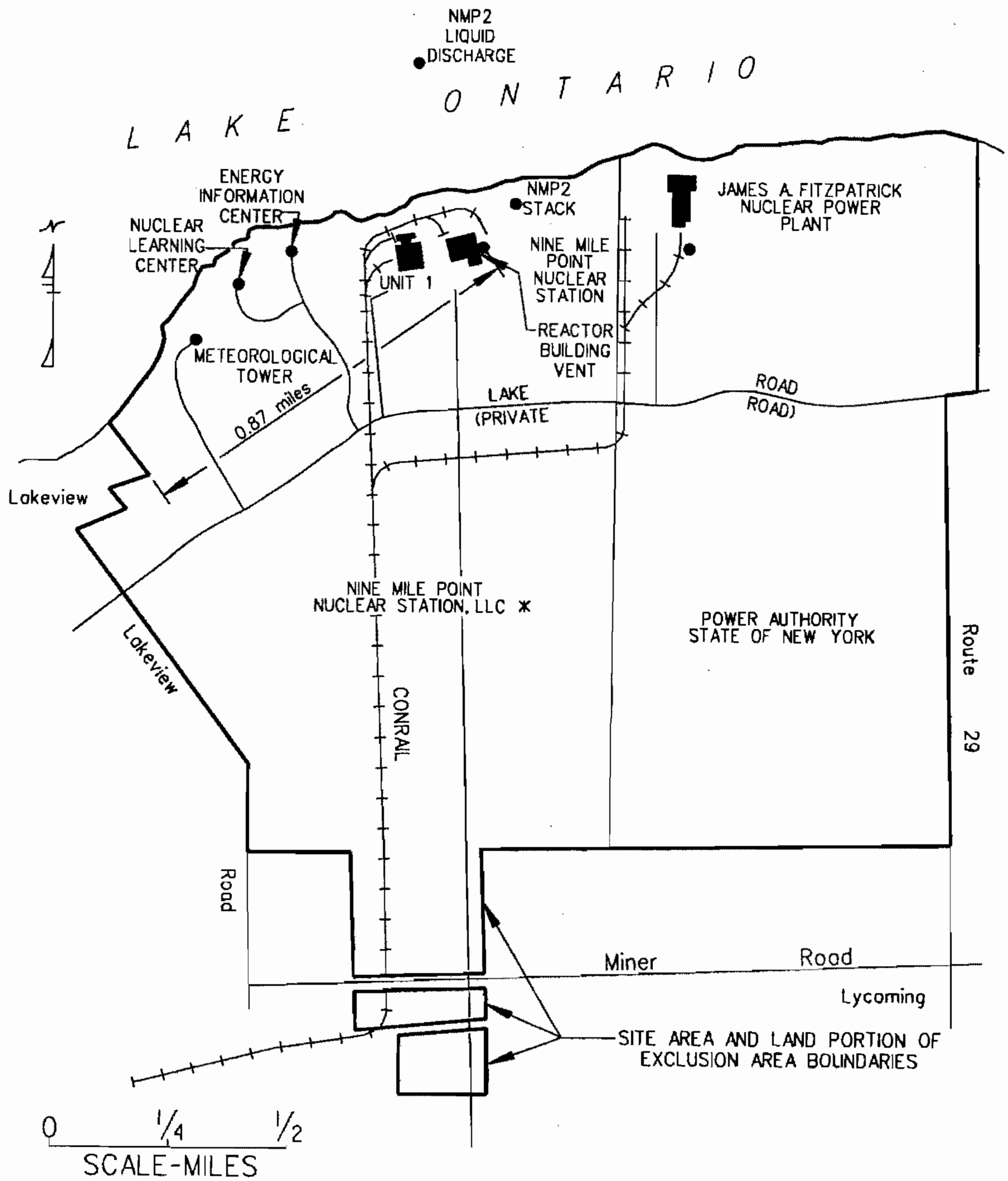
4.0 DESIGN FEATURES (continued)

4.3.2 Drainage

The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 329 ft 7 inches.

4.3.3 Capacity

The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 4049 fuel assemblies.



* Niagara Mohawk Power Corporation retains ownership in certain transmission line and switchyard facilities within the exclusion area boundary. Access and usage are controlled by Nine Mile Point Nuclear Station, LLC by Agreement.

Figure 4.1-1 (Page 1 of 1)
Site Area and Land Portion of Exclusion Area Boundaries

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR

REGULATION RELATED TO AMENDMENT NO. 140

TO FACILITY OPERATING LICENSE NO. NPF-69

NINE MILE POINT NUCLEAR STATION, LLC

NINE MILE POINT, UNIT NO. 2

DOCKET NO. 50-410

Proprietary information pursuant to
Title 10 of the *Code of Federal Regulations* Section 2.390
has been redacted from this document.
Redacted information is identified by blank space enclosed within double brackets

NINE MILE POINT NUCLEAR STATION, UNIT NO. 2
SAFETY EVALUATION FOR EXTENDED POWER UPRATE

TABLE OF CONTENTS

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO

AMENDMENT NO. 140 TO FACILITY OPERATING LICENSE NO. NPF-69

NINE MILE POINT NUCLEAR STATION, LLC

NINE MILE POINT, UNIT NO. 2

DOCKET NO. 50-410

1.0 INTRODUCTION

1.1 Application

By license amendment request (LAR) dated May 27, 2009,[1] as supplemented by additional letters,[2] Nine Mile Point Nuclear Station, LLC (NMPNS, the licensee) requested changes to the Renewed Facility Operating Licenses and Technical Specifications (TSs) for Nine Mile Point, Unit No. 2 (NMP2). The proposed amendment would increase the maximum steady-state reactor core power level from 3467 megawatts thermal (MWt) to 3988 MWt, which is an increase in thermal power of approximately 15 percent. The proposed increase in power level is considered an extended power uprate (EPU).

The supplemental letters received between December 23, 2009, and November 1, 2011, provided additional clarifying information that did not change the initial no significant hazards consideration determination noticed in the *Federal Register* on October 20, 2009 (74 FR 53778), and did not expand the scope of the original application.

1.2 Background

1.2.1 General Design Features

Nine Mile Point Nuclear Station, Unit No. 2 (NMP2) is a boiling-water reactor (BWR) plant of the BWR/5 design with a Mark-II containment. The U.S. Nuclear Regulatory Commission (NRC or the Commission) licensed NMP2 on July 2, 1987 for full-power operation at 3323 MWt. On October 31, 2006, the NRC renewed the license for NMP2.

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[1] Agencywide Documents Access and Management System (ADAMS) Accession Package No. ML091610091
[2] August 28, 2009 (ML092460610); December 23, 2009 (ML100190089); February 19, 2010 (ML100550598); April 16, 2010 (ML101120658); May 7, 2010 (ML101380306); June 3, 2010 (ML101610222); June 30, 2010 (ML101900471); July 9, 2010 (ML101950502); July 30, 2010 (ML102170191); September 16, 2010 (ML103050187); October 8, 2010 (ML102920339); October 28, 2010 (ML103080208); November 5, 2010 (ML103130515); December 10, 2010 (ML103500520); December 13, 2010 (ML103500363); January 19, 2011 (ML110250723); January 31, 2011 (ML110400373): February 4, 2011 (ML110460158); March 23, 2011 (ML110880300); May 9, 2011 (ML111370654); June 13, 2011 (ML111710135); July 15, 2011 (ML11207A069); August 5, 2011 (ML11207A069); August 19, 2011 (ML11242A044), September 23, 2011 (ML112700199); October 27, 2011 (ML113050319); and November 1, 2011 (ML113120336).

NMP2 is located on a 900-acre site owned by Nine Mile Point Nuclear Station, LLC (NMPNS or the licensee), and is situated on the southeast shore of Lake Ontario, Oswego County, New York, approximately 6.2 miles northeast of the city of Oswego. NMP2 and support facilities occupy about 45 acres, and share the site with the existing Nine Mile Point Nuclear Station, Unit No. 1 (NMP1) which has been in commercial operation since 1969. The Nine Mile Point site is adjacent to the James A. FitzPatrick Nuclear Power Plant owned by Entergy Nuclear FitzPatrick, LLC; NMP2 is located 900 ft. east of Unit 1 and about 2,350 ft. west of the James A. FitzPatrick Plant. Condenser cooling for Unit 2 is provided from a counterflow, natural-draft, hyperbolic concrete cooling tower. The ultimate heat sink for emergency core cooling is Lake Ontario. The low population zone surrounding Unit 2 encompasses an area within a 4-mile radius from the Unit 1 stack. The nearest population center with a population in excess of 25,000 is the city of Syracuse, approximately 32.8 miles southeast of the site.

1.2.2 Previous Power Uprate

NMPNS has performed a previous power uprate. This power uprate, termed a "stretch uprate," was approved on April 28, 1995, and increased the licensed thermal power from 3323 MWt to 3467 MWt, an approximate 4.3 percent increase from the original licensed thermal power.

1.2.3 Associated Technical Specification Amendments

1.2.3.1 Average Power Range Monitor/Rod Block Monitor Technical Specifications/Maximum Extended Load Line Limit Analysis

The NRC issued Amendment No. 123 to Renewed Facility Operating License No. NPF-69 for NMP2. The amendment consisted of changes to the Technical Specifications in response to the licensee's application dated March 30, 2007, as supplemented by letters dated October 16, 2007, and November 2, 2007. The amendment revised the NMP2 TSs to allow the expanded operating domain resulting from the implementation of average power range monitor/rod block monitor/technical specifications/maximum extended load line Limit Analysis (ARTS/MELLLA).

1.2.3.2 Full-Scope Implementation of Alternate Source Term

The NRC issued Amendment No. 125 to Renewed Facility Operating License No. NPF-69 for NMP2 on May 29, 2008. The amendment consisted of changes to the TSs in response to the licensee's application dated May 31, 2007, as supplemented by letter dated January 7, 2008. This amendment changed the NMP2 TSs by revising the alternate source term (AST) in the design basis radiological consequence analyses in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.67, which requires licensees who seek to revise their AST to apply for a license amendment under 10 CFR 50.90. The amendment revised the AST by replacing the methodology that is based on Technical Information Document (TID)-14844, "Calculation of Distance Factors for Power and Test Reactor Sites," with the alternative source term methodology described in Regulatory Guide (RG) 1.183, "Alternative Radiological Source Terms for Evaluating Design-Basis Accidents at Nuclear Power Reactors," with the exception that TID-14844 will continue to be used as the radiation dose basis for equipment qualification and vital area access. The amendment permitted full implementation of the alternate source term as described in RG 1.183. The licensee's AST evaluation was performed at the proposed EPU power level so that the design-basis accident (DBA) analyses could accommodate the licensee's s EPU submittal.

1.3 Licensee's Approach

The licensee's application for the proposed EPU follows the guidance in the Office of Nuclear Reactor Regulation's (NRR's) Review Standard (RS)-001, "Review Standard for Extended Power Uprates," Revision 0, December 2003, to the extent that the RS is consistent with the design basis of the plant. The guidance of RS-001 states that EPUs are characterized by power level increases of 7 percent or more and generally involve major plant modifications.

The licensee prepared its application for the proposed EPU following the guidelines contained in General Electric Nuclear Energy (GENE) Licensing TR (LTR) for Extended Power Uprate Safety Analysis, NEDC-33004P-A, "Constant Pressure Power Uprate," Revision 4, dated July 31, 2003. The NRC approved the constant pressure power uprate (CPPU) LTR, hereafter referred to as the "CLTR" in a SE dated March 31, 2003, for BWR plants containing GE fuel types and using General Electric Hitachi (GEH) accident analysis methods. NMP2 contains only GE fuel types and the licensee's proposed evaluation used only GEH accident analysis methods.

As part of its May 27, 2009, application, the licensee included as Attachment 11, the "Safety Analysis Report for Nine Mile Point Nuclear Station Unit 2, Constant Pressure Power Uprate," May 2009 (hereafter referred to as the Power Uprate Safety Analysis Report, or PUSAR). This report is an integrated summary of results of the safety analyses and evaluations performed that support the proposed increase in the maximum power level at NMP2. The PUSAR contains information that GEH considers proprietary. The report follows the generic content and format using the CPPU approach to uprating reactor power, as described in the CLTR. Attachment 3 to the NMPNS application contains a nonproprietary (i.e., publicly available) version of the PUSAR.

The licensee's method for achieving higher power is to extend the power/flow map along the maximum extended load line limit developed as part of the Maximum Extended Load Line Limit Analysis. There would be no increase in the maximum normal operating reactor vessel dome pressure or the maximum licensed core flow over their pre-EPU values. EPU operation would not involve increasing the maximum normal operating reactor vessel dome pressure, because the plant, after modifications to non-safety power generation equipment, has sufficient pressure control and turbine flow capabilities to control the inlet pressure conditions at the turbine.

1.4 Plant Modifications

The licensee's planned modifications[3] as stated in its LAR to support implementation of the NMP2 EPU analyses include the following:

[3] Modifications to several reactor recirculation system (RCS) components such as the RCS jet pump inlet mixers which will be performed during the 2012 refueling outage are not included in the aforementioned list, as these modifications are intended to optimize plant performance at EPU conditions but are not necessary prior to power increase.

Modification	Description
Replace FW Heater Drain Pumps and Motors	Replace pump internals Replace pump motors Replace 4th point heater drain level control valve trim
Replace High Pressure Turbine	Replace the high pressure turbine for increased steam flow at EPU conditions
Steam Dryer modifications	Reinforce the inner and middle hood end cover welds and the lifting rod upper brace to vane bank weld
Replace 3rd Point feedwater heaters	Replace three third point feedwater heaters (not an Extended Power Uprate (EPU) modification - the heaters require replacement before the plant operates under EPU conditions. There is strong evidence that shows excessive wear and damage to the tube supports under current operating conditions. The damage has worsened as time progressed and if operating conditions were more severe, the detrimental effects on the tubes and tube supports would be greater)
Improve Main Transformer Cooling	Install upgraded cooling system on main generator step-up transformers
Upgrade Reactor Feedwater Pumps and Gear Sets	Replace pump impellers Replace pump speed increasers Flow control valve changes Feedwater system setpoint setdown setting change Re-rate feedwater system piping/valves
Extraction Steam Expansion Joints	Replace extraction steam expansion bellows for the 'B' and 'C' 1st through 4th point feedwater heater extraction lines (not an EPU modification - being replaced due to equipment degradation, same rationale as feedwater heater replacement).
Equipment Qualification Modifications	Install shielding on the two standby gas treatment system filters
Isolate Abandoned Turbine Building Closed Loop Cooling (TBCLC) Loads	Isolate abandoned loads Rebalance the TBCLC system
Improve Turbine Building Heating, Ventilation and Air Conditioning (HVAC)	Installation of four additional area coolers located near the condensate and condensate booster pumps

Feedwater Heater Requalification	Re-rate the 5th and 6th point feedwater heaters Replace the 6th point heater shell side safety valves Replace the scavenging steam relief valves
Main Steam, Feedwater, and Balance of Plant Piping Support Replacement	Revise piping supports as necessary for EPU conditions
Replace Low Pressure Turbine Cross Around Relief Valves Replace Low Pressure Turbine Cross Around Relief Valves	Replace cross around relief valves with valves rated for EPU conditions Re-rate the cross around piping, moisture separators, drain tanks and intermediate heat exchangers
Replace Low Pressure Turbine Atmospheric Relief Diaphragms	Replace six low pressure turbine atmospheric exhaust hood diaphragms
Temporary Vibration Monitoring	Install accelerometers on Main Steam, Feedwater, Extraction Steam and balance of plant (BOP) piping for vibration monitoring (temporary)
Instrument Replacement and Modification	Replace seven instruments to meet EPU conditions Recalibrate 227 instrument loops Change various setpoints Change various computer points
Recirculation Runback Initiation and Runback Rate	Revise Reactor Recirculation System (RRS) runback logic to initiate upon a feedwater/condensate booster pump trip Increase recirculation flow control valve runback rate to 9 percent per second
Generator Isolated Phase Bus Duct Cooling	Modify the isolated phase bus duct housings to provide additional cooling
Design Basis Document Updates to Support EPU Implementation	Design basis reconciliation/configuration control. No physical work involved.
Condensate Demineralizer Bypass	Install a partial bypass line around the condensate demineralizers
Main Steam Line Vibration Monitoring Strain Gauges	Install strain gauges to record the dynamic pressure fluctuations inside the main steam piping in the drywell.

Section 2.0 of this SE provides the NRC staff's evaluation of the licensee's proposed plant modifications.

1.5 Method of NRC Staff Review

The NRC staff based its review of the NMP2 EPU application on NRC RS-001, "Review Standard for Extended Power Uprates," issued December 2003 (Reference 16). RS-001 contains guidance for evaluating each area of review in the application, including the specific General Design Criteria (GDC), given in Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," used as the NRC's acceptance criteria.

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 EPU on design-basis analyses. The staff evaluated the licensee's application and supplements. The staff also performed audits of analyses supporting the EPU and performed independent calculations, analyses, and evaluations as noted below.

In areas where the licensee and its contractors used NRC-approved methods in performing analyses related to the proposed EPU, 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 effects of the changes in plant operating conditions on the use of these methods to ensure that the methods are appropriate for use for the proposed EPU conditions. Section 2.0 of this SE provides details of the staff's review.

The NRC staff and its contractors conducted audits of the analyses supporting the proposed EPU in relation to the following topics:

- The application of the generically approved interim methods licensing TR (IMLTR, NEDC-33173P), "Applicability of GE Methods to Expanded Operating Domains" (see SE Section 2.8)

- Thermal Hydraulic Design: Long-term stability solution Option III and impact of EPU on anticipated transient without scram (ATWS)-Stability events (see SE Section 2.8)

In addition, the NRC staff performed a first-time review of the licensee's proposed methodology related to steam dryer structural integrity analyses, Acoustic Circuit Model Revision 4.1 (see SE Section 2.2)

2.0 EVALUATION

2.1 Materials and Chemical Engineering

2.1.1 Reactor Vessel Material Surveillance Program

Regulatory Evaluation

The reactor pressure vessel (RPV) material surveillance program provides a means for determining and monitoring the fracture toughness of the RPV beltline materials to support analyses for ensuring the structural integrity of the ferritic components of the RPV. The NRC staff's review primarily focused on the effects of the proposed EPU on the licensee's RPV surveillance capsule withdrawal schedule. The NRC's acceptance criteria are based on the following points:

1. GDC-14, insofar as it requires that the reactor coolant pressure boundary (RCPB) be designed and constructed so as to have an exceedingly low probability of gross rupture, significant leakage, or rapidly propagating failure;

2. GDC-31, insofar as it requires that the RCPB be capable of accommodating without rupture, and with only limited allowance for energy absorption through plastic deformation, the static and dynamic loads imposed on any boundary component as a result of any inadvertent and sudden release of energy to the coolant;

3. 10 CFR Part 50, Appendix H that provides for monitoring changes in the fracture toughness properties of materials in the RPV beltline region;

4. 10 CFR 50.60 requires compliance with the requirements of 10 CFR Part 50, Appendix H. Specific review criteria are contained in Standard Review Plan (SRP) Section 5.3.1 and other guidance provided in Matrix 1 of RS-001, Revision 0, *Review Standard for Extended Power Uprates* (December 2003).

Technical Evaluation

The NRC's regulatory requirements related to the establishment and implementation of a facility's RPV materials surveillance program and surveillance capsule withdrawal schedule are given in 10 CFR Part 50, Appendix H. Two specific alternatives are provided with regard to the design of a facility's RPV surveillance program which may be used to address the requirements of Appendix H to 10 CFR Part 50.

The first alternative is the implementation of a plant-specific RPV surveillance program consistent with the requirements of American Society for Testing and Materials (ASTM) Standard Practice E 185, "Standard Practice for Conducting Surveillance Tests for Light-Water Cooled Nuclear Power Reactor Vessels." In the design of a plant-specific RPV surveillance program, a licensee may use the edition of ASTM Standard Practice E 185 that was current on the issue date of the American Society of Mechanical Engineers Boiler and Pressure Vessel Code (ASME Code) to which the RPV was purchased, or later editions through the 1982 edition.

The second alternative provided in Appendix H to 10 CFR Part 50 is the implementation of an integrated surveillance program (ISP). An ISP is defined in Appendix H to 10 CFR Part 50 as occurring when, "the representative materials chosen for surveillance for a reactor are irradiated in one or more other reactors that have similar design and operating features."

The proposed EPU will increase the neutron flux, which increases the integrated fluence over the remainder of the license and increases the embrittlement of the beltline materials. The licensee discussed the impact of the EPU on the RPV material surveillance program in Section 2.1.1 of Attachment 3 to its letter dated May 27, 2009. This section indicates that NMP2 will participate in the Boiling Water Reactor Vessel and Internals Project (BWRVIP) ISP as the method by which the NMP2 RPV will comply with the requirements of 10 CFR Part 50, Appendix H. Under the ISP, NMP2 is not a host plant; therefore, the EPU will have no effect on the ISP as outlined in BWRVIP-116, "BWR Vessel and Internals Project Integrated Surveillance Program (ISP) Implementation for License Renewal."

Conclusion

The NRC staff has reviewed the licensee's evaluation of the changes in neutron fluence due to the proposed EPU at NMP2 and concludes that the ISP remains bounding for the NMP2 RPV. The NRC staff further concludes that the ISP is appropriate to ensure that the material surveillance program will, following implementation of the proposed EPU, 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 31. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RPV material surveillance program.

2.1.2 Upper-Shelf Energy (USE), Pressure-Temperature (P-T) Limits, and Inspection of Circumferential Welds

Regulatory Evaluation

In 10 CFR Part 50, Appendix G, Section IV (A), two fracture toughness requirements are outlined for ferritic materials (low alloy steel or carbon steel) materials in the RCPB. The first includes requirements on the Charpy USE values used for assessing the safety margins of the RPV materials against ductile tearing. The second requirement covers the P-T limits and minimum temperature requirements for the plant. The 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 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 effective full power years (EFPY) specified for the proposed EPU, considering neutron embrittlement effects, which use linear elastic fracture mechanics. The NRC's acceptance criteria for Charpy USE and P-T limits evaluations are based on:

1. GDC-14, insofar as it requires that the RCPB be designed and constructed so as to have an exceedingly low probability of gross rupture, significant leakage, or rapidly propagating failure,

2. GDC-31, insofar as it requires that the RCPB be capable of accommodating without rupture, and with only limited allowance for energy absorption through plastic

deformation, the static and dynamic loads imposed on any boundary component as a result of any inadvertent and sudden release of energy to the coolant,

3. 10 CFR Part 50, Appendix G that specifies fracture toughness requirements for ferritic components of the RCPB; and

4. 10 CFR 50.60 that 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, Revision 0, *Review Standard for Extended Power Uprates* (December 2003).

Technical Evaluation

USE Value Calculations

The criteria for acceptable levels of USE for the RPV beltline materials of operating reactors requires RPV beltline materials to have a minimum USE value of 75 ft-lb in the un-irradiated condition, and to maintain a minimum USE value above 50 ft-lb throughout the life of the facility, unless it can be demonstrated through analyses that lower values of USE would provide margins of safety against fracture equivalent to those required by Appendix G of Section XI to the 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 RPV surveillance capsule data that are reported through implementation of a plant's 10 CFR Part 50, Appendix H, RPV materials surveillance program.

The licensee discussed the impact of the EPU on the Charpy USE values for the RPV beltline materials in Section 2.1.2 of Attachment 3 to their letter dated May 27, 2009. This section references Table 2.1-1, "Upper Shelf Energy - 60 Year Life (54 EFPY)," in Attachment 3. The table indicated that the projected Charpy USE value for the limiting beltline material will be 61 ft-lbs (well above the 50 ft-lbs minimum required in Appendix G). The NRC staff notes that this data is consistent with USE value for the limiting material that was previously published in NUREG-1511, "Reactor Pressure Vessel Status Report," [4] because the neutron fluence value projected to 54 EFPY under EPU conditions is slightly less than that used in NUREG-1511.

P-T Limit Calculations

Appendix G of 10 CFR Part 50 requires that the RPV be operated within established P-T limits during heatup and cooldown. These limits specify the maximum allowable pressure as a function of reactor coolant temperature. The NMP2 TSs contain P-T limit curves for heatup, cooldown, inservice leakage testing, and hydrostatic testing, and they limit the maximum rate of change of reactor coolant temperature. The P-T limit curves are periodically revised to account for changes in fracture toughness of the RPV components due to anticipated neutron embrittlement effects for higher accumulated fluences. Calculation of P-T limit curves using the projected fluence at the end of the period of extended operation would result in unnecessarily restrictive operating curves over the near term; however, projection of the Adjusted Reference Temperature (ART), which is used in development of the curves, to the end of the period of extended operation under the EPU provides assurance that development of P-T limit curves will

[4] NUREG-1511, "Reactor Pressure Vessel Status Report", December 1994 (ML082030506).

be feasible up to the maximum predicted EFPY. There are no regulatory requirements for the maximum ART for BWRs. The need to minimize the ART is driven by operational considerations. The current P-T curves found in the TSs[5] are valid and will remain valid up to a wetted inside surface fluence of 5.71×10^{17} n/cm^2 (E > 1 MeV).

Circumferential Weld Inspection

ASME Code, Section XI, Table IWB-2500-1 requires inspection of all RPV reactor vessel welds at regular intervals. In a letter from the NRC dated November 5, 2007[6], the licensee received inspection relief for the circumferential welds until the end of the unit's extended license with an estimated fluence at the ¼ T location of 8.6×10^{17} n/cm^2 (E > 1 MeV). The basis for the relief request was the BWRVIP-05 TR[7] where the BWRVIP committee concluded that the conditional probabilities of failure for BWR RPV circumferential shell welds are orders of magnitude lower than that of the axial shell welds. The NMP2 RPV circumferential weld parameters under pre-EPU operating conditions were bounded by the parameters used in the subject TR and this allowed the NRC to grant relief from future inspections of the circumferential shell welds.

The proposed EPU for NMP2 significantly increases the neutron flux and over the course of the extended license period, the neutron fluence on the beltline materials will increase. In section 2.1.2 "Pressure-Temperature Limits and Upper-Shelf Energy," of Attachment 3 to their letter dated May 27, 2009, the licensee reevaluated the irradiation effects (including operation under EPU conditions until the end of the extended license) on the circumferential weld properties. Table 2.1-3 compared the results to the limiting values for vessels made by Chicago Bridge & Iron (CB&I). After considering the effects of the EPU, the mean value of RT_{NDT} was 88 °F lower than for the bounding value presented in BWRVIP-05 for CB&I vessels after 64 EFPY. Since the limiting NMP2 RPV circumferential weld RT_{NDT} value continues to be bounded by the analysis in the BWRVIP-05 Report, the conditional failure probability of the circumferential welds at NMP2 is bounded by the requirements of the NRC for license renewal[8] and the values specified in the SE for the BWRVIP-05[9]. The licensee must still submit an amended relief request, separate from their EPU application and in accordance with the requirements of 10 CFR 50.55a, in order to obtain relief from the subject ASME Code inspection requirements under EPU operating conditions through the expiration of the extended NMP2 license.

In a letter dated December 23, 2009, the staff asked the following question:

> (RAI-CVIB-1) The submittal refers to BWRVIP-74 on pages 2-3 and in Table 2.1-3. Is BWRVIP-74 the proper reference? This should refer to the SER for BWRVIP-05. NMP2 should commit to submitting an updated request for relief reflecting the data

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[5] May 27, 2009, License Amendment Request Pursuant to 10 CFR 50.90: Extended Power Uprate, ADAMS Accession No. ML091610103.
[6] Letter from Mark G. Kowal (NRC) to Keith J. Polson (Nine Mile Point Nuclear Station), November 5, 2007, ADAMS Accession No. ML072830047.
[7] BWRVIP-05, "BWR Vessel and Internals Project [BWRVIP], BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations", EPRI report TR-105697, September 1995.
[8] Letter from C.I. Grimes (NRC) to Carl Terry (BWRVIP), October 18, 2001, ADAMS Accession No. ML012920549.
[9] Letter from G.C. Lainas (NRC) to Carl Terry (BWRVIP), "Final SE of the BWR Vessel Internals Project BWRVIP-05 Report", July 28, 1998.

shown in Table 2.1-3, which will reflect the higher fluence at 54 EFPY for the EPU conditions.

In its RAI response dated February 19, 2010, the licensee stated that the submittal references the BWRVIP program primary document BWRVIP-74, which provides the requirements that must be satisfied for circumferential weld relief. BWRVIP-74 Section A.4.1 references the NRC SE for BWRVIP-05 as the source. The licensee concluded that the BWRVIP-74 is considered an acceptable reference source.

NMPNS also stated in its RAI response that their EPU submittal demonstrated that the weld parameters for the circumferential welds (1.58 x 10^{17} n/cm^2 (E>1MeV), a conservative projected fluence under EPU conditions) remain bounded by the values specified in BWRVIP-74. They consider their commitment to maintain a RG 1.190 fluence program as adequate evidence that the approved fluence level (8.6 x 10^{17} n/cm^2) will not be exceeded without an update to the relief request. In a separate correspondence[10], the NRC staff stated that it would be appropriate for the licensee to commit to submit a revised relief request for elimination of the circumferential reactor vessel weld inspection a full year before the currently approved fluence is reached. NMPNS agreed to make the commitment in Attachment 4 to the May 7, 2010, letter to the NRC[11].

The NRC staff finds the licensee's commitment to submit a revised relief request for elimination of the circumferential reactor vessel weld inspection a full year before the currently approved fluence is reached acceptable and considers RAI-CVIB-1 resolved.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU, and concludes that the licensee has adequately addressed changes in neutron fluence and their effects on the USE values and the P-T limits for NMP2 RPV beltline materials. The staff concludes that the NMP2 beltline materials will continue to have acceptable USE values, as mandated by 10 CFR Part 50, Appendix G, through the expiration of the current operating license for the facility. The NRC staff further concludes that the licensee has demonstrated that the proposed P-T limits and the relief from circumferential weld inspection remain valid for continued operation under the proposed EPU 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 31 in this respect following implementation of the EPU. Therefore, the NRC staff finds the EPU acceptable with respect to the Charpy USE and the P-T limits under the proposed EPU conditions.

[10] Email from R. Guzman (NRC) to T. H. Darling (NMPNS), dated April 14, 2010, ADAMS Accession No. ML1013000062.
[11] Letter from T. Lynch (NMPNS) to NRC, dated May 7, 2010, ADAMS Accession No. ML101380307.

2.1.3 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 reactor coolant system (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 and BWRVIP-26 "BWRVIP Vessel and Internals Project, BWR Top Guide Inspection and Flaw Evaluation Guidelines," and Matrix 1 of RS-001, Revision 0, *Review Standard for Extended Power Uprates* (December 2003).

Technical Evaluation

Reactor internals and core support materials are at risk of crack initiation and growth due to four distinct mechanisms:

1. stress-corrosion cracking due to intergranular stress-corrosion cracking (IGSCC) and/or irradiation assisted stress-corrosion cracking (IASCC),

2. loss of fracture toughness due to thermal aging and neutron embrittlement,

3. crack initiation and growth due to flow induced vibration, and

4. cumulative fatigue damage.

The last two mechanisms are discussed in Section 2.2 of this SE. Mechanisms 1 and 2 are managed through the inservice inspection program that conforms to the requirements of 10 CFR 50.55a and the BWRVIP, which is reviewed and approved by the NRC. The inspections that are recommended by the BWRVIP supplement the inservice inspection program required by 10 CFR 50.55a.

Section 10.7 of the NEDC-33004P-A report, "Constant Pressure Power Uprate," Rev. 4, identifies mechanism 1 (IASCC) as a degradation mechanism that may be significantly affected by the increased neutron fluence associated with the proposed EPU. The licensee also states that it has a procedurally-controlled program that is consistent with the BWRVIP documents for the augmented inspection of selected RPV internal components (core spray piping and sparger, core shroud and its support, jet pumps and associated components, top guide, lower plenum, vessel inside diameter (ID) attachment welds, instrumentation penetrations, steam dryer drain channel weld, and feedwater spargers) in order to ensure their continued structural integrity. In addition, three components are specifically noted for attention due to projected 54 EFPY fluence that exceed the BWRVIP-26[12] threshold fluence level of 5×10^{20} n/cm^2 (E > 1 MeV) for potential susceptibility to IASCC:

1. Top Guide, 4.04×10^{22} n/cm^2 (E > 1 MeV)

2. Core Shroud, 5.1×10^{21} n/cm^2 (E > 1 MeV)

3. Core Plate, 6.61×10^{20} n/cm^2 (E > 1 MeV)

The continuation of this existing program based on the BWRVIP recommendations is expected to ensure the structural integrity of each of the components for the life of the license under EPU conditions. In addition, NMP2 utilizes hydrogen water chemistry (HWC) and noble metal chemical additions (NMCA) to mitigate the potential for SCC. RPV water chemistry conditions are also maintained consistent with BWRVIP-62.

In a letter dated December 23, 2009, the staff asked the following question:

> (RAI-CVIB-2) Since the licensee stated that it is incorporating HWC and NMCA program, the staff requests that the licensee should identify the method of controlling HWC/NMCA in the RPV. Provide details on the methods for determining the effectiveness of HWC/NMCA by using the following parameters:
>
> (1) electrochemical potential (ECP),
> (2) feedwater hydrogen flow,
> (3) main steam oxygen content, and
> (4) hydrogen /oxygen molar ratio.

In a letter dated February 19, 2010, the licensee stated that NMP2 is a BWRVIP-62 Category 3b plant. NMCA application was performed on September 12, 2000. As recommended for Category 3b plants, NMP2 obtained measurements of hydrogen and oxygen, for determination of the molar ratio, from a post-NMCA hydrogen ramping test. The measurements confirmed that the plant's response was consistent with the selected hydrogen injection rate or feedwater hydrogen concentration identified by General Electric Nuclear Energy (GENE) as required to achieve mitigation based on model results. The hydrogen injection rate is continuously monitored.

Online Noble Metal Application was implemented at NMP2 in 2007. This method has applications performed during power operations on an approximately annual frequency. The effectiveness monitoring is performed by process controls and platinum feed monitoring during On Line Noble Chemistry (OLNC) application supplemented with coupons.[13] The staff considers the proposed methods as described in the licensee's letter dated February 19, 2010, to be sufficient to address RAI-CVIB-2 regarding the control of HWC/NMCA in the RPV.

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[12] BWRVIP-26-A, "BWR Vessel and Internals Project, BWR Core Plate Inspection and Flaw Evaluation Guideline", EPRI Technical Report 1009946, November 2004.

[13] NMP2 installed an ECP probe to monitor the OLNC application effectiveness. This ECP was used during the initial OLNC application to monitor the deposition and the effectiveness of the application. The ECP is not used as a method of controlling HWC/NMCA on a routine basis.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU 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 with respect to material specifications, welding controls, and inspection following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to reactor internal and core support materials.

2.1.4 Protective Coating Systems (Paints) – Organic Materials

Regulatory Evaluation

Protective coating systems (paints) protect the surfaces of facilities and equipment from corrosion and radionuclide contamination. The coatings also provide wear protection during plant operation and maintenance activities. The staff's review covered protective coating systems used inside containment, including the coating's suitability for, and stability under, design-basis loss-of-coolant accident (DBLOCA) conditions, considering radiation and chemical effects. The NRC acceptance criteria for protective coating systems are based on: (1) 10 CFR Part 50, Appendix B, "Quality Assurance Criteria For Nuclear Power Plants and Fuel Reprocessing Plants," which covers quality assurance requirements for design, fabrication, and construction of safety related SSCs, and (2) RG 1.54, Revision 1, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," July 2000, which covers application and performance monitoring of coatings in nuclear power plants.[14] Specific review criteria are contained in SRP Section 6.1.2, "Protective Coating Systems (Paints) – Organic Materials Responsibilities."

Technical Evaluation

The licensee stated that the protective systems used inside the containment were evaluated for their continued suitability for, and stability under, DBLOCA conditions. The evaluation considered radiation and chemical effects at the EPU conditions. The licensee provided information illustrating that the post loss-of-coolant accident (LOCA) containment environmental conditions, such as temperature, pressure, and radiation, do not significantly change as a result of the EPU, and the chemical constituency of the protective coatings does not change. The licensee stated that the Service Level 1 protective coatings used at NMP2 were qualified per ANSI N101.2-1972 to a radiation level of 1×10^9 Rads and a temperature of 340 °F. Under EPU conditions, the peak DBLOCA radiation level is 9.32×10^8 Rads, and the temperature of 285 °F, and therefore the coating systems for primary containment would still perform their function and remain bounded for the DBA conditions.

[14] Per the NMP2 Updated Safety Analysis Report Table 1.8-1, the NMP2 commitment to RG 1.54 is to Revision 0, dated June 1973.

The licensee also stated that the NMP2 Protective Coating Monitoring and Maintenance Program is an existing program that is described in the NMP2 response to GL 98-04, "Guidance on Developing Acceptable Inservice Testing Programs," and that this program was developed in accordance with ANSI N101.4-1972, along with ANSI/ASME NQA-1-1983. This program applies to Service Level 1 protective coatings inside the primary containment.

The NRC staff has reviewed the licensee's evaluation and has verified that the applicable regulatory guidance was followed. The staff concurs that the post LOCA containment environmental conditions do not significantly change under EPU conditions. In addition, the chemical constituency of the protective coatings does not change under EPU conditions. The licensee has demonstrated that the protective coating systems remain acceptable for EPU operation.

Conclusion

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

2.1.5 Flow-Accelerated Corrosion

Regulatory Evaluation

Flow-accelerated corrosion (FAC) is a corrosion mechanism occurring in carbon steel components exposed to single-phase or two-phase water flow. 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 flow velocity, fluid temperature, steam quality, oxygen content, and pH. During plant operation, flexibility to control these parameters to minimize FAC is limited. Loss of material by FAC will, therefore, occur.

The NRC staff has reviewed the effects of the proposed EPU on FAC and the adequacy of the licensee's FAC program. The intent of the FAC program is to predict the rate of loss so that repair or replacement of damaged components can be made before they reach critical thickness. The licensee's FAC program is based on NUREG-1344, "Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants," April 1989, NRC Generic Letter (GL) 89-08, "Erosion/Corrosion - Induced Pipe Wall Thinning," May 1989, and the guidelines in Electric Power Research Institute (EPRI) Report NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program," April 1999. It consists of predicting loss of material using the CHECWORKS™ FAC computer code, 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.

Technical Evaluation

The licensee stated that the FAC program at NMP2 monitors all FAC susceptible piping, both small and large bore, to ensure structural integrity and functionality are maintained. Selection of locations for FAC inspection and replacement or degraded piping is accomplished using CHECWORKS™, susceptibility ranking of locations not modeled by CHECWORKS™, NMP2 and industry operating experience, trending of historical inspection data, and sound engineering judgment. The CHECWORKS™ FAC model is updated after each refueling outage. The licensee stated that the EPU will affect some variables that influence FAC, such as operating temperature, steam quality, velocity and oxygen content. To account for these changes, the licensee has updated the affected parameters in the CHECWORKS™ model based on the EPU heat balance diagram.

The licensee also stated that over the next several refueling outages, there may be an increase in the number of FAC inspections performed on locations not modeled by CHECWORKS™ as well as locations that are modeled by CHECWORKS™. The increased inspections would be performed to ensure the impact of the power uprate is understood. Inspections will be selected considering the changes in predicted wear rates, actual component thicknesses, operating time since last examination, and design margin. This approach will ensure that FAC susceptible components are inspected or replaced prior to reaching code minimum wall thickness. No immediate replacements have been planned prior to EPU implementation.

In a letter dated December 23, 2009 (ADAMS Accession No. ML100190072), the licensee addressed staff concerns regarding CHECWORKS™ predicted wear rate decreases at some locations listed in Table 2.1-5 of the May 27, 2009, submittal. In their response, the licensee stated that the influence of temperature on FAC is represented by a bell curve. FAC rates increase as temperature increases up to approximately 300 °F and then decrease as the temperature continues to increase beyond 300 °F. The slopes of the bell curve are steep, which results in a relatively large decrease in wear rate based on a relatively small increase in temperature. The licensee also stated that the influence of velocity on the rate of FAC is fairly linear. The slope of the velocity curve is relatively flat indicating that larger changes in velocity will have a lesser impact on rate of FAC degradation verses temperature change influences on FAC. The components questioned in the RAI all had temperature and velocity increases as a result of EPU conditions.

The licensee stated that the negative changes in predicted FAC wear rate indicated that the increase in temperature resulted in a larger overall reduction in the predicted wear rate than the corresponding increase in FAC from velocity, thus a net reduction in the predicted wear rate for the components in question in Table 2.1-5 of the May 27, 2009, submittal.

The NRC staff finds the licensee's response to the RAI acceptable because it clearly explains the influences of temperature and velocity on the rate of FAC for the components in question. The staff concerns regarding CHECWORKS™ predicted wear rate decreases have been resolved.

The NRC staff has reviewed the licensee's evaluation and has verified that the applicable regulatory guidance was followed. The licensee has demonstrated that the FAC program is adequate for managing the potential affects on the nuclear steam supply system (NSSS), turbine generator, and BOP components. The NRC staff concurs that the FAC program is adequate in predicting the rate of material loss, and therefore repair or replacement of damaged components can be made before they reach a critical thickness.

Conclusion

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

2.1.6 Reactor Water Cleanup System

Regulatory Evaluation

The reactor water cleanup (RWCU) system provides a means for maintaining reactor water quality by filtration and ion exchange and a path for removal of reactor coolant when necessary. Portions of the RWCU comprise the RCPB. The staff's review of the RWCU included component design parameters for flow, temperature, pressure, heat removal capability, impurity removal capability, and the instrumentation and process controls for proper system operation and isolation. The review consisted of evaluating the adequacy of the plant's TSs in these areas under proposed EPU conditions. The NRC's acceptance criteria for the RWCU are based on: (1) 10 CFR Part 50 Appendix A GDC-14, "Reactor Coolant Pressure Boundary," as it requires that the RCPB be designed, fabricated, erected, and tested to have an extremely low probability of rapidly propagating fracture; (2) GDC-60, "Control of Releases of Radioactive Materials to the Environment," as it requires that the plant design include means to control the release of radioactive effluents; and (3) GDC-61, "Fuel Storage and Handling and Radioactivity Control," as it requires systems that contain radioactivity to be designed with appropriate confinement. Specific review criteria are contained in SRP Section 5.4.8, "Reactor Water Cleanup System (BWR)."

Technical Evaluation

The RWCU will operate at a slightly decreased temperature under EPU rated thermal power. The temperature decrease is less than 1 degree Fahrenheit from the temperature under the current license thermal power (CLTP). Under the lower EPU temperature, the RWCU system is capable of performing its function of removing solid and dissolved impurities from recirculated reactor coolant, thereby reducing the concentration of radioactive and corrosive species in the reactor coolant.

RWCU flow is usually between 0.8 and 1.0 percent of the feedwater system flow. The EPU analyzed flow is within the operational history range. The EPU analysis also included evaluations of water chemistry, heat exchanger performance, pump performance, flow control valve capability, and filter/demineralizer performance. The performance of each of the above mentioned parameters was found to be within the design of the RWCU system at the analyzed flow for EPU conditions. The EPU analysis concluded that:

- There is negligible heat load effect
- A small increase in filter/demineralizer backwash frequency occurs, but this is within the capacity of the Radwaste system
- The slight changes in operating system conditions result from a decrease in inlet temperature and increase in feedwater system operating pressure
- The RWCU filter/demineralizer control valve operates in a slightly more open position to compensate for the increased feedwater system pressure
- No changes to instrumentation are required; and setpoint changes are not expected due to the negligible system process parameter changes.

There is a slight increase in the calculated reactor water conductivity from 0.102 μS/cm to 0.110 μS/cm because of the increase in feedwater system flow. As a result of the EPU, the pressure in the feedwater line increases and has a slight effect on the system operating conditions. Previous operating experience has shown that the feedwater system iron input to the reactor increases for EPU as a result of the increased feedwater system flow. This change is considered insignificant and does not affect the RWCU. Also, since the feedwater system flow increases while the RWCU flow remains the same, sulfate and chloride concentrations will increase above CLTP levels. Chlorides are expected to increase from 0.70 ppb in CLTP conditions to 0.82 ppb for EPU conditions. Sulfates are expected to increase from 2.34 ppb in CLTP conditions to 2.75 ppb in EPU conditions. The administrative limit is 5.0 ppb for chlorides and 5.0 ppb for sulfates. The estimated increase in these parameters is not significant and sufficient operating margin to the conservative limits remain under the EPU conditions.

The licensee reviewed the effects of the EPU on the RWCU system functional capabilities and determined that RWCU can adequately perform at the EPU power level with the original RWCU system flow.

The NRC staff has reviewed the licensee's evaluation and has verified that the applicable regulatory guidance was followed. The staff concurs that the proposed EPU will introduce only insignificant changes in the RWCU operating parameters, which will not affect satisfactory performance of its intended function.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects the proposed EPU will have on the RWCU and concludes that the licensee has adequately addressed changes in impurity levels and pressure, and their effects on the RWCU. The NRC staff further concludes that the licensee has demonstrated that the RWCU will continue to be acceptable following implementation of the proposed EPU. Specifically, the RWCU will continue to meet the requirements of GDC-14, GDC-60 and GDC-61. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RWCU.

2.1.7 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 IGSCC is contained in Generic Letter (GL) 88-01 and NUREG-0313, as modified by BWRVIP-75-A, "Technical Basis for Revisions to Generic Letter 88-01 Inspection Schedules." Additional review guidance for thermal embrittlement of cast austenitic stainless steel components is contained in a letter from C. Grimes, NRC, to D. Walters, Nuclear Energy Institute (NEI), dated May 19, 2000.

Technical Evaluation

The RCPB piping at NMNPS that was evaluated for EPU included the following systems: reactor recirculation system (RRS), main steam (MS), reactor core isolation cooling (RCIC), high-pressure core spray (HPCS), feedwater (FW), reactor water cleanup (RWCU), core spray (CS), standby liquid control (SLC), residual heat removal (RHR), reactor pressure vessel head vent, reactor pressure vessel bottom drain, main steam relief valve discharge line (MSVDL), control rod drive hydraulic (CRDH), and primary chemistry sampling. In its proposed license amendment, the licensee stated that the reactor recirculation system was generically evaluated in accordance with the process described in NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1 or Reference 18); and NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR2 or Reference 19). The licensee's evaluation determined that the proposed EPU will not affect the RCPB piping. The staff finds the licensee's conclusion acceptable because the above evaluation was performed in accordance with the processes identified in TRs ELTR1 and ELTR2 which the staff has previously reviewed and approved. Therefore, the NRC staff agrees with the licensee's conclusion that the RCPB materials will not be significantly affected after the EPU is implemented.

Due to the history of IGSCC in BWR RCPB materials, the staff requested additional information regarding the licensee's disposition of the reactor coolant system (RCS) piping. In response to the staff's RAI, the licensee stated in its letter dated December 23, 2009 (ML100190072) that NMPNS has no IGSCC Category B, C, F, or G weldments, as defined in NUREG-0313, and has implemented an augmented IGSCC inspection program in accordance with GL 88-01 and NUREG-0313, as modified by BWRVIP-75-A (ML053070151). This technical report has been previously reviewed and approved by the NRC staff (ML060750725). The staff notes that the licensee's augmented inspection program for Category D welds, with 100 percent of the population examined every 6 years, is based on the requirements for normal water chemistry (NWC) even though NMPNS employs hydrogen water chemistry (HWC) which would allow an inspection frequency of 50 percent in the first 6 years and 100 percent in 10 years. Since the augmented inspection program for Category D welds meets the BWRVIP-75-A inspection requirements for welds with NWC, the staff finds it acceptable.

The staff requested that the licensee identify the disposition of Category E welds, whether they have been reinforced by weld overlay or mitigated by stress improvement treatment. Two Category E welds were identified, a nozzle-to-safe end weld (weld ID 2RPV-KB-20) on which a full structural weld overlay repair in accordance with ASME Code Case N-504-2 was performed, and a safe-end-to-safe end extension weld (weld ID 2PRV-KC-32) which was mitigated by the mechanical stress improvement process (MSIP). The NMPNS augmented inspection program for Category E welds mitigated by a full structural weld overlay requires 25 percent of these welds to be inspected every 10 years with 50 percent of the examinations completed within the first 6 years of the interval. In response to further staff questions, the licensee stated in its letter dated February 19, 2010 (ML100550601) that the Category E weld that was mitigated by MSIP will be examined once every 6 years. Since the examination frequencies of both of these Category E welds meet the requirements of BWRVIP-75-A, the staff finds the augmented inspection program for Category E welds acceptable.

In response to the staff's RAI information concerning monitoring of electrochemical potential for IGSCC mitigation, the licensee stated that NMNPS does not rely on HWC alone for IGSCC mitigation. NMNPS has adopted the OLNC process of noble metal injection along with HWC. While the electrochemical potential is not monitored, catalyst loading is monitored with the Mitigation Monitoring System and the measured H_2:O_2 molar ratio is monitored by means of reactor water chemical analysis. The licensee stated that the hydrogen injection rate will be increased from the present value of 15 standard cubic feet per minute (scfm) before the EPU to 17.6 scfm after the EPU. This is a 17 percent hydrogen injection rate increase to compensate for the increased radiolysis oxygen generation of the 15 percent power uprate. The licensee will monitor the H_2:O_2 molar ratio and adjust the hydrogen injection rate to maintain the H_2:O_2 molar ratio of 3 or more. The staff finds these measures are adequate to control water chemistry for IGSCC mitigation, and thus are acceptable.

In summary, the staff finds that the licensee's conclusion that the proposed EPU will not affect the RCPB piping is acceptable. Additionally, the staff has determined that the augmented IGSCC inspection program and the measures to control water chemistry for IGSCC mitigation at NMPNS are acceptable.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU 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 EPU 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 EPU acceptable with respect to RCPB materials.

2.2 Mechanical and Civil Engineering

2.2.1 Pipe Rupture Locations and Associated Dynamic Effects

Regulatory Evaluation

Structures, systems and components (SSCs) important to safety at nuclear power plants 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 at NMP2 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 inservice inspection (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 CPPU may have on items (1) through (4) above. The NRC staff'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 licensee performed plant-specific and generic evaluations for high energy line breaks (HELBs) and cracks and moderate energy line cracks (MELCs). The licensee's review of the effects of CPPU on the postulated pipe rupture locations and associated dynamic effects for NMP2 is documented in the NMP2 PUSAR, which follows the CPPU approach of the NRC approved GE CLTR. From a review of the NMP2 updated safety analysis report (USAR), the staff notes that the current licensing basis (CLB) evaluation criteria for postulating pipe break and crack locations are contained in NMP2 USAR Section 3.6 and are in accordance with the SRP Section 3.6.2, BTP MEB 3-1. In response to a staff RAI, the licensee stated that the CLB HELB criteria were also used for EPU HELB analysis.

For the postulation of HELBs, the licensee determined EPU pipe code stresses and fatigue cumulative usage factors (CUFs) using guidance provided in Appendix K of the NRC-approved ELTR1. Therefore, the NRC staff finds the licensee's methodology acceptable. Appendix K provides guidance in determining pipe stress increases by the use of scaling factors from pressure, temperature, and flow increases for CPPU. In the PUSAR and in responses to staff RAIs, the licensee showed that it evaluated high energy (HE) systems inside and outside containment for EPU. From the HE systems inside containment that the licensee evaluated, the following are affected by EPU and experience increases in pipe stresses and/or cumulative usage factors due to EPU: feedwater system (FWS), main steam system (MSS), main steam vent (MSV), main steam drain Lines (MSDL), reactor core isolation cooling (RCIC) steam line and MS safety relief valve (SRV) stand pipes (piping between MS line and each SRV). From the HE systems outside containment whose failure (per USAR Table 3.6A-73) could impact essential systems/components/equipment, the following are affected by EPU and experience increases in pipe stresses due to EPU and were evaluated by the licensee: MSS, FWS, and RWCS. The licensee also evaluated moderate energy (ME) systems. In response to a staff

RAI, the licensee stated that for ME systems, it performed evaluations where it reviewed the changes in operating/design pressure and temperature due to EPU. The licensee also stated that the following ME systems outside of containment experience increases in pipe stresses due to the proposed EPU: circulating water (CW), turbine building closed loop cooling water system (CCS) and condensate demineralizers (CND).

In the PUSAR and in the licensee's response to a staff RAI, the licensee provided evaluation summaries of the affected piping systems, identified above, which show that at EPU conditions no new break or crack locations need to be postulated. The staff reviewed the licensee's evaluations, including pipe stress summaries and fatigue CUFs, at EPU conditions. The staff found the licensee's evaluations acceptable because the evaluations follow an NRC-approved methodology and the current plant licensing and design basis without making changes to the implementation of the existing criteria for defining pipe break and crack locations.

Effects of Postulated Pipe Failures

Steam Line High Energy Line Breaks (HELB)

The NRC approved CLTR states that "CPPU has no effect on the steam pressure or enthalpy at the postulated break locations. Therefore, CPPU has no effect on the mass and energy releases from a HELB in a steam line. Therefore, no plant-specific evaluation is required for steam line breaks." The licensee stated that the steam line HELB events in the NMP2 licensing basis were evaluated and confirmed to be consistent with the generic description provided in the CLTR. In addition, the licensee's evaluations have shown that there are no new postulated break locations required for EPU. Therefore, the staff concurs with the licensee that the EPU has no effect on the mass and energy releases from an HELB in a steam line, and as such, no plant-specific evaluation is required for steam line breaks.

Liquid Line HELB

Operation at EPU conditions requires an increase in the MS and FW flows, which results in an increase in FW system pressures. The licensee noted that this increase in pressure may lead to increased break flow rates for liquid line breaks in the FW and WCS systems. The licensee re-evaluated the HELB mass and energy releases at EPU conditions for the WCS and FWS. With regard to the WCS, the licensee's EPU HELB evaluation found that the increase in system operating pressure is bounded by existing analytical conservatisms and that the EPU mass releases remain bounded by the existing (CLTP) mass releases. The licensee also stated that no changes are being made to the automatic leak detection logic or to any leak detection system settings as a result of EPU. The licensee also re-evaluated the mass and energy releases for double-ended breaks and critical cracks in the FW lines. The licensee found that the effects of a FW system line break on main steam tunnel peak pressures and temperatures are bounded by a main steam line break in the main steam tunnel and stated that for the portion of the smaller WCS piping attached to the FW piping in the main steam tunnel, mass and energy releases from breaks in the smaller WCS piping are bounded by the FW break mass and energy releases.

For further review of the evaluations of the effects of postulated pipe breaks, including that of mass and energy releases at pipe break locations, see Section 2.5, "Plant Systems" for outside containment and Section 2.6, "Containment Review Considerations."

Pipe Whip and Jet Impingement

The staff notes that pipe whip and jet impingement loads resulting from high energy pipe breaks are directly proportional to system pressure, pipe break area, and jet coefficients (for jet thrust loads) for saturated steam, saturated water, steam/water mixture and for nonflashing subcooled water. As mentioned above, the CLTR states that, "CPPU has no effect on the steam pressure or enthalpy at the postulated break locations." In addition, according to licensee's evaluations, there are no new steam pipe break locations postulated due to EPU. Therefore, pressure and break area have not changed for postulated steam breaks at EPU conditions. Hence, the NMP2 EPU has no effect on steam line breaks pipe whip and jet impingement loads. The licensee has provided its summary evaluation for pipe whip and jet impingement in its PUSAR, which is supplemented by the licensee's responses to staff RAIs. The licensee stated that inside containment, the only high energy piping that experiences an increase in operating pressure due to EPU is the FWS. Outside containment, the only high energy piping that experiences an increase in operating pressure due to EPU is the FWS and WCS. The licensee evaluated the jet impingement load increase in the WCS and FWS. As stated in its response to a staff RAI, the licensee determined that for EPU, the WCS maximum pressure increases by 2 psi and the temperature decreases by 0.3 °F, compared to the existing analyzed conditions. Therefore, the staff concurs with the licensee that the EPU impact on the WCS line break loads is negligible due to EPU.

In its response to a staff RAI, the licensee stated that the FW line break jet impingement loads inside containment increase by approximately 12 percent. For the increased FW jet impingement loads inside containment, the licensee's response included a tabulated summary evaluation of safety related (SR) jet impingement targets which indicates that, for targets affected by jet impingement loads resulting from postulated FW line breaks, either the current analysis uses a larger bounding load (F) or there is available margin in the target structural capacity. According to the licensee, current analysis stress (S) ratios (actual CLTP values over allowable values) are less than 25 percent. The staff notes that by setting the maximum existing design basis stress equal to 25 percent of the allowable and scaling it up in proportion to the loads by 12 percent, the maximum EPU predicted stress is approximately equal to 28 percent of the allowable stress:

$$S_{epu} = 1.12 \times 0.25 S_{al} = 0.28 S_{al}$$

S_{epu} = EPU stress
S_{al} = Allowable stress

As such, it is demonstrated that adequate margin exists at EPU conditions. Therefore, based on its review, the staff notes that the EPU does not adversely affect the structural integrity of safety related SSCs from pipe break generated loads.

During its review, the NRC staff noted that GEH issued Safety Communication (SC) 09-01 to address an error in their methodology that developed Annulus Pressurization (AP) loads. This SC lists NMP2 as one of the affected plants. The AP dynamic loads result from a postulated circumferential pipe break at the interface of the RPV nozzle safe-end and its connected piping that penetrates the Bioshield wall. In its response to a staff RAI by letter dated April 16, 2010 (ML101120658), the licensee has shown that the NMP2 EPU evaluations have considered the GEH SC09-01 in the evaluation of the AP loads, and that the EPU evaluations also corrected errors that were found in the original design basis calculations. The licensee noted that the results of these evaluations show that all reactor vessel and internals, and associated vessel attachments and supports, remain consistent with the plant's design basis. The staff reviewed the licensee's response and finds that there is reasonable assurance that containment SSCs important to safety will continue to be protected from dynamic effects of the AP loads resulting from the aforementioned pipe break.

The DBA LOCA dynamic loads, including the pool swell loads, vent thrust loads, condensation oscillation loads and chugging loads were originally defined and evaluated for NMP2. The evaluation of the structures attached to the containment wetwell such as piping systems, vent penetrations, and valves are based on these DBA LOCA hydrodynamic loads. For EPU conditions, the licensee re-evaluated these DBA LOCA wetwell response loads and found that they are unchanged by EPU. Therefore, there are no resulting effects on the containment wetwell attached structures. The licensee also determined that the safety relief valve (SRV) discharge loads are not affected by the proposed EPU.

On the basis of the NRC staff's review, the NRC staff finds the licensee's evaluation of postulated pipe failures, their associated dynamic effects and effects of DBA LOCA and SRV loads for EPU acceptable based on the acceptance criteria found in GDC-4 and SRP 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 EPU on them using current licensing and design basis methods and criteria. 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 CPPU. Therefore, the NRC staff finds the proposed CPPU 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 CPPU 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

2.2.2.1 Nuclear Steam Supply System Piping, Components, and Supports (Inside Containment)

The RCPB piping consists of a number of safety related piping subsystems that move fluid through the reactor and other safety systems. The RCPB piping systems the licensee evaluated for CPPU include the reactor recirculation (RRS) system, control rod drive (CRD) system, residual heat removal (RHR) low-pressure coolant injection (LPCI) lines, core spray (CS) injection lines, standby liquid control system (SLCS) injection line, reactor pressure vessel (RPV) bottom head drain line, MS piping and MS Drain, FW piping, the RPV head vent line, safety relief valve (SRV) discharge piping. In addition, the licensee in its evaluations addressed branch lines, piping supports, nozzles, penetrations, flanges, and valves. The licensee also evaluated the safety related thermowells in the MS and FW systems and the sample probe in the FW system for FIV due to increased flows in the MS and FW systems resulting from EPU implementation.

The licensee evaluated the above RCPB piping systems in accordance with the methodology documented in the GE CLTR. In response to a staff RAI, the licensee stated that the piping systems affected by EPU inside containment were evaluated for 102 percent EPU power conditions which is consistent with the plant current licensing basis. The licensee, in its response to a staff RAI, verified that all structural evaluations of SSCs, required for EPU, were performed in accordance with the DB code of record (ASME Code Section III, 1974 Edition) and the existing design basis methodology for piping and pipe supports. To determine EPU values, the licensee scaled CLTP design basis pipe stresses, fatigue usage factors and pipe support loads in proportion to pressure, temperature and flow increases for CPPU. The licensee's piping evaluation follows the methodology described in Appendix K of the NRC-approved GE ELTR1 and, therefore, the NRC staff finds the licensee's methodology acceptable.

The licensee's PUSAR indicates that loadings which would affect stresses and fatigue usage factors on piping systems and loads on pipe supports due to pressures, temperatures, flows and mechanical loads do not increase or change at EPU conditions for most of the RCPB piping systems. This assessment is consistent with the staff-approved CLTR. In addition, seismic loads are not affected by EPUs and the licensee has determined that the SRV discharge loads are also not affected by the proposed CPPU. The NRC staff finds this acceptable because the proposed EPU does not change the SRV setpoints, and is consistent with the NRC staff-approved methodology of ELTR1.

The licensee reviewed the RRS system, CRD system, RHR-LPCI, CS injection lines, SLCS injection line, and RPV bottom head drain line and [[ ]] these as acceptable for operation at the proposed EPU conditions, in accordance with the CLTR. The staff finds the licensee's disposition and justification for [[ ]], presented in Section 2.2.2 of PUSAR, acceptable as it follows the CLTR approach and because parameters affecting the structural integrity of these piping sections have shown either no change or have shown insignificant change for EPU.

Systems inside containment that are most affected by a CPPU at a BWR facility are the MS and FW systems, primarily because of the increased flows in these systems. For the NMP2 proposed CPPU, it has been estimated that the steam and feedwater flows will increase by a maximum of [[ ]], with some minor increases in system temperature and pressure. As mentioned above, to determine the applicable ASME Code equation stresses and fatigue usage factors in the affected piping systems, the licensee employed scaling factors for flow, temperature and pressure in accordance with the staff approved methodology of ELTR1.

The licensee's scaling factors for ASME class 1 MS and FW piping inside and outside containment are shown in PUSAR Table 2.2-2a. For Class 1 MS and FW piping inside and outside containment, the licensee's reported summaries show that calculated stresses are within their ASME Code allowable values and, therefore, are acceptable. The licensee also reported the calculated MS and FW DW penetrations stress summaries, which are also shown to be within ASME Code allowable values and, therefore, acceptable. In addition, the licensee's PUSAR presents MS and FW pipe support and equipment nozzle EPU load summaries (including MSRV flange load summary which shows that flange loads increased due to the TSV load case) which are also found to be within design basis allowable limits and, therefore, are acceptable for EPU conditions. It is noted that the ELTR1 Appendix K methodology of scaling factors and subsequent pipe stress and pipe support load derivation is a very conservative approach.

The licensee noted that by applying these conservative factors in the evaluation of the MS system pipe supports at EPU conditions, four of the MS pipe supports exceeded their allowable limits. According to the PUSAR, a plant-specific steam hammer analysis was performed to determine the MS loads due to the turbine stop valve fast closure (TSVC) transient. These loads were used to develop plant-specific scaling factors for the TSVC load case which were subsequently used to recalculate pipe support reaction loads. The TSVC is considered one of the most significant loads in the qualification of MS piping and supports. According to the staff approved CLTR, TSVC loads bound the MSIV closure event because the MSIVs are slow closing valves compared to the TSVs.

The licensee determined from the plant-specific steam hammer analysis that the maximum piping support load increase inside containment due to TSV closure, was 27 percent. This factor was conservatively applied to the CLTP TSV closure support load to determine the EPU loads. This evaluation resulted in all main steam pipe supports inside containment meeting the acceptance criteria. The staff agrees that this approach is conservative and finds that all supports are within their design basis allowable limits, and, therefore, are acceptable for EPU conditions. In addition, the SRV's setpoint pressures do not change for CPPU, and, therefore, SRV actuation loads remain unchanged for the proposed EPU. Based on the above, the staff finds that the licensee has considered all applicable loads for EPU and has found the class 1 piping inside containment, including the class 1 portion outside containment of FW and MS, structurally acceptable for EPU conditions.

The licensee evaluated the FIV levels associated with the MS and FW piping systems that are projected to increase for CPPU. The staff's evaluation of FIV and power ascension and testing programs for CPPU are documented in Section 2.2.6 of the staff's SE.

The licensee also determined stresses due to FIV for fatigue considerations for the three safety related thermowells in each of the MS and FW systems and the sample probe in the FW system. The staff reviewed the licensee's methodology for calculating oscillating lift and drag forces due to vortex shedding which follows the guidance of ASME Code Section III, Appendix N, Subsection N-1300. The staff finds this methodology acceptable for this application. However, the acceptance of this limited application does not infer endorsement of Appendix N. The staff notes that the tabulated stresses due to FIV at EPU conditions, shown in PUSAR, are within ASME Code fatigue allowable stress limits for steady state vibration and are derived using guidance of ASME O&M- Standards and Guidelines (S/G) Part 3, Subparagraph 3.2.1. Therefore, the six safety-related thermowells in the MS and FW systems and the sample probe in the FW system that the licensee evaluated are structurally adequate for the EPU increased MS and FW flow rates.

The licensee also evaluated the EPU effect on the AP loads. The licensee discussed its evaluations in PUSAR Section 2.2.2. The licensee has also provided responses to the staff's RAIs in reference to the GEH issued SC 09-01, which address potential issues in the methodology that developed the Annulus Pressurization (AP) loads. The staff reviewed the PUSAR evaluation summaries and the licensee's responses to the staff's RAIs. The licensee, during its review to assess the impact of the EPU on the AP loads, identified errors in the original design basis analyses. For EPU evaluations, the licensee has considered the increased AP loads resulting from SC09-01 and has also corrected the errors in the original design basis calculations. As a result of these evaluations, new AP dynamic loads for the RPV and its internals and new AP acceleration response spectra (ARS) for attached piping were developed. The new AP dynamic loads were combined with the containment hydrodynamic loads and used to reanalyze the RPV and internals. The new ARS spectra were used in the revised analysis of attached piping to assess the impact on pipe stress, nozzle loads, pipe support loads and containment penetrations. The licensee's RAI responses indicate that results of structural evaluations show that the loads on the RPV, internals, attached piping, nozzles, supports and containment penetrations remain consistent with the plant's design basis and, therefore are acceptable.

The licensee, using the plant current licensing and design basis methodology and acceptance criteria, has evaluated the structural integrity of the NSSS piping and supports, the primary equipment nozzles, and the primary equipment supports. Based on its review as summarized above, the staff agrees with the licensee that the NSSS piping, components and supports are structurally adequate for the proposed power uprate.

2.2.2.2 Balance-of-Plant Piping, Components, and Supports

The licensee evaluated the structural integrity of the BOP piping, components and supports to assess the impact of operating temperature, pressure and flow rate changes that will result due to the implementation of EPU. In response to a staff RAI, the licensee provided the following list of safety related and non-safety related piping systems outside containment for which temperature, pressure and or flow have been increased due to EPU conditions:

> Main steam, extraction steam, feedwater, condensate and condensate demineralizers, reactor water cleanup, moisture separator and, reheater vents and drains, high pressure/low pressure drains, feedwater pump recirculation and balance drum leakoff, auxiliary steam, turbine plant miscellaneous drains, circulating water system, turbine generator gland seal and exhaust steam, radwaste auxiliary steam, control rod drive hydraulics, feedwater pump seals and leakoff, condenser air removal, off gas, auxiliary condensate, feedwater heater relief vents and drains, condensate makeup/drawoff and hot reheat.

The licensee evaluated safety related piping in accordance with the current design basis code of record; ASME Code Section III, 1974 Edition. The licensee also evaluated non-safety related piping affected by the EPU utilizing the criteria found in the design basis code of record; ANSI B31.1 1973, including Addenda through C.

The licensee, in response to staff's RAIs, confirmed that the increased flow rate due to CPPU only affects the structural analysis (pipe stress and support loads) of the MS and FW piping and that the structural analyses of all other systems inside and outside of containment are not affected by flow rate. Also, the increase in MS pipe stresses and fatigue CUFs (class 1 piping) is only due to the increased TSVC transient loads, as the changes in the MS temperature and pressure are negligible. The licensee evaluated the FW piping for changes in flow, temperature and pressure. In response to a staff RAI, the licensee stated that the structural calculations of the FW lines included loads for water hammer due to control valve closure and feedwater pump trip in the evaluations of pipe stresses, pipe breaks, and pipe support loads. These loads are increased due to the higher EPU flows. The load increase is accounted for in the factors provided in PUSAR Tables 2.2-2a and 2.2-2b.

In response to a staff RAI, the licensee discussed the FW line thermal stratification inside and outside containment. The licensee identified that in reevaluating the FW line thermal stratification for EPU conditions, it found that the FW MOV21B, which is subjected to thermal stratification monitoring, satisfies the licensing basis fatigue CUF allowable value of equal to or less than 0.1 for break exclusion areas for the 40-year plant life (of 2026). However, the licensee found that FW MOV21B exceeds the 0.1 CUF allowable for the 60-year plant life extension (to 2046). The licensee indicated that if the plant fatigue monitoring program (FatiguePro) predicts that fatigue usage cannot be maintained below 0.1, then corrective actions such as re-analysis, enhanced inspection or repair/replacement will be implemented.

In Reference 54, NMPNS submitted the following regulatory commitment regarding its stress based monitoring program:

> In accordance with ASME Section III NB-3200, stress based fatigue monitoring at NMP2 shall include all six stress components.

The staff understands that if stress based fatigue monitoring is used, the licensee will include the six stress terms in accordance with ASME Section III, NB-3200. The NRC provides the following license condition in section 3.0 of this SE (License Condition 3.4.2) pertaining to the licensee's use of the stress based monitoring program.

> If stress based fatigue monitoring is used, it shall include all six stress terms in accordance with NB-3200. The condition for this requirement will be carried over and be applicable for operation under EPU conditions and in the plant life extension to 60 years.

The staff finds that the licensee's response, with the above licensing condition applied, provided reasonable assurance that measures are in place to ensure that the CUF allowable will continue to be satisfied for operation under EPU including the period of operation after 40 years.

In response to a staff RAI, the licensee submitted a table which identifies that, in addition to MS and FW piping, other systems that are mostly affected by the EPU (due to increases in their temperatures and/or pressures) are the Extraction Steam (ESS), FW Heater Vents & Drains (HDH, HDL and SVH), Moisture Separator Reheater Vents and Drains (DSR and DSM) and Auxiliary Condensate (CNA). The licensee evaluated these systems and, in its response to the staff's RAI, provided tabulated pipe stress summaries. The staff reviewed the pipe stress summaries presented in the licensee's PUSAR and in its responses to the staff's RAI and found that maximum reported pipe stresses for BOP piping affected by the EPU are all within the design basis code of record allowable values and, therefore, are acceptable.

The licensee also evaluated BOP pipe supports in accordance with the current design basis. Attachment 6 of the EPU LAR contains the modifications required for the EPU and states that MS, FW and BOP supports will be revised, as necessary. In response to a staff RAI, the licensee indicated that piping modifications due to EPU increased parameters (flow rate, pressure and temperature) are not required and that the only pipe support that needs modification is condensate support 2CNM-PSR085A4, due to a limiting weld that needs to be built up. On April 8, 2011, in response to a follow-up RAI, the licensee stated that it performed a more detailed structural evaluation of support 2CNM-PSR085A4 which determined that modification of this support is not required. The staff concludes that the licensee has shown in its PUSAR and responses to staff's RAIs that BOP pipe supports have been evaluated in accordance with the NMP2 current design basis and found to be structurally adequate for EPU conditions and, therefore, acceptable for EPU.

The licensee's PUSAR notes that the MS and FW piping have increased flow rates and flow velocities in order to accommodate CPPU. As a result, the MS and FW piping experience increased vibration levels, approximately proportional to the square of the flow velocities. Attachment 10 to the licensee's LAR submittal, "Flow Induced Vibration-Piping/Component Evaluation," provides additional information on the plant system piping and components, including MS and FW piping and components, which might be subject to increased FIV due to CPPU. The vibration acceptance criteria for the licensee's power ascension program for CPPU are documented in ASME O/M-S/G Part 3, "Requirements for Preoperational and Initial Start-Up Vibration Testing of Nuclear Power Plant Piping Systems." The licensee evaluated the FIV levels associated with the MS and FW piping systems that are projected to increase for CPPU. The staff's reviews of the licensee's FIV and power ascension and testing programs for CPPU are documented in Sections 2.2.6 and 2.12 of the staff's SE.

The licensee [[ ]] the MS line flow elements (restrictors) for structural integrity in accordance with the CLTR. The licensee's structural integrity review of the MS line flow restrictors is documented in the proprietary portion of Section 2.5.4.1, "Main Steam," of PUSAR which finds that there is no effect on the structural integrity of the MS line flow restrictors due to the EPU. The NRC staff finds the licensee's review of the MS line flow restrictors for CPPU to be acceptable.

The NRC staff finds that the licensee, using the current design basis and code of record, has adequately addressed the effects of the proposed EPU on the BOP piping, pipe components and pipe supports. Based on its review, as summarized above, the staff concludes that the proposed EPU does not adversely affect the structural integrity of the BOP piping, pipe components and pipe supports.

2.2.2.3 Reactor Vessel and Supports

The licensee evaluated the effects of the proposed EPU on the RPV structure and support components for the design, normal, upset, emergency and faulted conditions, in accordance with the plant's current design basis. In its evaluation, the licensee utilized the methodology documented in the NRC approved power uprate GEH LTRs (CLTR, ELTR1, and ELTR2). In accordance with this methodology, the licensee compared the proposed power uprate conditions (pressure, temperature and flow) against those used in the current design basis evaluations and reviewed existing OLTP component stress reports (including modifications) to identify components having a [[

]].

The licensee, in accordance with the CLTR, performed [[

]]. In the case of NMP2, the operating license of which has been extended from 40 to 60 years, the 0.5 CUF value has been scaled down by 1.5 (to reflect the 60-year plant life) which results in a CUF threshold of 0.33. The staff finds the licensee's methodology acceptable, as it is in accordance with the NRC approved power uprate GEH licensing TRs and adjustments have been made to account for the 60-year plant life due to the plant renewed license.

Maximum stress and fatigue evaluation summary results for components affected by the power uprate are presented in PUSAR Table 2.2-6 which show that the code of record allowable limits have been met for these components. The licensee noted that the feedwater nozzles meet the ASME Code fatigue CUF allowable value of 1.0 for the 40-year plant life, but they will exceed it for the 60-year plant life. The licensee indicated that if the plant fatigue monitoring program (FatiguePro) predicts that fatigue usage cannot be maintained below 1.0, then corrective actions such as re-analysis, enhanced inspection or repair/replacement will be implemented.

In Reference 54, NMPNS submitted the following regulatory commitment regarding its stress based monitoring program:

> In accordance with ASME Section III NB-3200, stress based fatigue monitoring at NMP2 shall include all six stress components.

The staff understands that if stress based fatigue monitoring is used, the licensee will include the six stress terms in accordance with ASME Section III, NB-3200. The NRC provides the following license condition in section 3.0 of this SE (License Condition 3.4.2) pertaining to the licensee's use of the stress based monitoring program:

> If stress based fatigue monitoring is used, it shall include all six stress terms in accordance with NB-3200. The condition for this requirement will be carried over and be applicable for operation under EPU conditions and in the plant life extension to 60 years.

The staff finds that the licensee's response, with the above licensing condition applied, provided reasonable assurance that measures are in place to ensure that the CUF allowable will continue to be satisfied for operation under EPU including the period of operation after 40 years.

The licensee also evaluated the effect of the AP loads at EPU conditions on SSCs important to safety and found that associated vessel attachments and supports remain consistent with the plant's design basis. The staff's review of the AP dynamic loads is contained in Sections 2.2.1 and 2.2.2.2.1.

Based on the NRC staff's review of the licensee's evaluation of the RPV structures and support components for CPPU, the NRC staff finds that maximum stresses and fatigue usage factors are within code-allowable limits. Therefore, the staff concurs with the licensee's conclusion that the RPV structures and support components will continue to maintain their structural integrity at the proposed EPU conditions.

2.2.2.4 Control Rod Drive Mechanism

The licensee's evaluation of the CRD mechanism for CPPU is documented in the proprietary portion of Sections 2.2.2 and 2.8.4.1.3 of PUSAR. The PUSAR states that the [[

]]. According to the CLTR, the reactor operating condition for a CPPU does not affect the CRD pump discharge pressure. The staff has previously accepted the CLTR's conclusion that the maximum calculated stress for the limiting CRDM component (CRD system pressure-regulating valve that applies the maximum pump discharge pressure to the CRD mechanism internal components) is not affected by the CPPU. The licensee has confirmed that the NMP2 CRD system integrity [[

]]. Based on its review as summarized above, the staff agrees that the structural integrity of the CRD mechanism is maintained for the proposed EPU conditions.

2.2.2.5 Recirculation Pumps and Supports

The staff reviewed the licensee's evaluation of the recirculation pumps and supports documented in the proprietary portion of Section 2.2.2 of the PUSAR. For the proposed NMP2 EPU operation, [[

]]. Therefore, the NRC staff finds that the licensee has provided reasonable assurance that RRS system pumps and supports will remain structurally adequate at EPU conditions.

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 EPU 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 EPU. Therefore, the NRC staff finds the proposed EPU 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 reactor vessel, including core support structures. The NRC staff reviewed the effects of the proposed CPPU 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 flow-induced vibration for safety related and non-safety related reactor internal components (steam dryer review is discussed in Section 2.2.6 of this SE) 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 anticipated operational occurrences. 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 RPV internals consist of core support structure (CSS) and non-core support structure components. The licensee notes that the RPV internals are not certified in accordance with the provisions of the ASME Code. However, the licensee's design basis analyses for the RPV internals used the ASME Code criteria as guidelines. The licensee used the same guidelines to reevaluate the RPV internals for the normal, upset, emergency and faulted conditions for CPPU (steam dryer is addressed in Section 2.2.6 of this SE). The loads considered in the evaluation were consistent with the existing design basis and include deadweight, seismic, reactor internal pressure differences (RIPDs), SRV, LOCA, AP, jet reaction (JR), acoustic and flow induced loads (AFIL), fuel lift loads, SCRAM and thermal loads. [[ ]]. The resulting stresses are compared against the design basis code allowable values.

The licensee's methodology in evaluating the RPV internals is consistent with the NRC approved BWR EPU TRs (see Section 2.2.0) and, therefore, is acceptable. The licensee performed qualitative and quantitative assessments of the RPV internals. The licensee's results of the qualitative assessments are presented in Section 2.2.3 of the PUSAR. The licensee's results of the quantitative assessments are contained in the proprietary portion of Section 2.2.3 of the PUSAR. Summary of maximum stresses and fatigue CUFs are presented on Tables 2.2-10 and 2.2-11 of the PUSAR. All stresses and CUFs are shown to be within design basis allowable limits and, therefore, are acceptable.

With respect to the effects of FIV on the RPV internal components, the licensee indicated that the steam separators and dryers in the upper elevations of the RPV are the components most affected by the increased steam flow at EPU conditions. Components in the core region are primarily affected by the core flow. Components in the annulus region, such as the jet pump, are primarily affected by the recirculation pump drive flow and core flow. The licensee indicated that the maximum core flow rate remains unchanged. The staff also notes that [[ ]]. Therefore, the changes in FIV due to EPU in the core and annulus regions are small.

Evaluations were performed to assess the effects of FIV on the RPV internals at EPU conditions. These evaluations used a reactor power of 3988 MWt and 105 percent of rated core flow. [[ ]]. For components requiring an evaluation, but not instrumented in [[ ]] and on GE Nuclear Energy BWR operating experience to the EPU power. [[ ]]. These expected EPU vibration levels were then compared with the established vibration acceptance limits. [[ ]] therefore, accumulate no fatigue usage due to FIV.

The peak stresses were calculated at critical locations and found to be within the GE design criterion acceptance peak stress limit of [[ ]]. Peak stress intensity values less than [[ ]] are within the endurance limit under which sustained operation is allowed without incurring any cumulative fatigue usage. Summaries of the licensee's structural evaluations of the RPV internals due to FIV for EPU are presented in Section 2.2.3 of the PUSAR. The licensee concluded that vibration levels of all safety related reactor internal components are within the GE established acceptance criteria. The licensee also noted that peak stress limit of [[ ]] is conservative in comparison to the ASME Code peak stress limit of 13,600 psi (for austenitic steels). The licensee's FIV evaluation methodology is described in Section 2.2.3 of the PUSAR. The staff considers the licensee's methodology to be acceptable and similar to methodologies used in previously approved BWR power uprates.

Based on the review above, the NRC staff's concurs with the licensee's conclusion that the RPV internals will continue to maintain their structural integrity at CPPU conditions. The steam dryer assembly is addressed separately in Section 2.2.6 of this SE.

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 CPPU 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 CPPU. Therefore, the NRC staff finds the proposed CPPU acceptable with respect to the structural integrity of the reactor internals and core support structures.

2.2.4 Safety-Related Valves and Pumps

Regulatory Evaluation

The NRC staff's review included safety related valves and pumps designated as Class 1, 2 or 3 under Section III of the ASME Code and within the scope of the ASME *Code for Operation and Maintenance of Nuclear Power Plants* (OM Code). The NRC staff's review focused on the effects of the proposed EPU on the required functional performance of valves and pumps at NMP2. The review also covered any impacts that the proposed EPU might have on the licensee's motor-operated valve (MOV) programs related to GL 89-10, "Safety Related Motor-Operated Valve Testing and Surveillance; GL 96-05, "Periodic Verification of Design-Basis Capability of Safety Related Motor-Operated Valves;" and GL 95-07, "Pressure Locking and Thermal Binding of Safety Related Power-Operated Gate Valves." 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 AOVs. The NRC's acceptance criteria are based on: (1) GDC-1, insofar as it requires those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed, fabricated, erected and tested to quality standards commensurate with the importance of the safety functions to be performed; (2) GDC-37, 40, 43, and 46, insofar as they require that the emergency core cooling system, the containment heat removal system, the containment atmospheric 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 Power Uprate Review Standard RS-001.

Technical Evaluation

In its submittals dated May 27 and December 23, 2009, and February 19, 2010, the licensee discussed its evaluation of safety related valves and pumps to perform their intended functions under EPU conditions. Section 2.2.4 of Attachment 3 of the EPU license amendment request addresses the impact of EPU on the performance requirements of NMP2 safety related valves and pumps in the IST, MOV and air-operated valve (AOV) programs. The NRC staff has reviewed the licensee's evaluation of the impact of EPU conditions on safety related valves and pumps. This review is summarized in the following paragraphs.

In response to GL 89-10 and GL 96-05, a testing and surveillance program was established for MOVs. The NRC acceptance of the GL 89-10 MOV program for NMP2 was documented in NRC Inspection Report 50-410/97-09 dated November 4, 1997 (Accession Number 9711120038). In a letter dated July 18, 2000 (Agencywide Documents Access and Management System Accession Number ML003729304), the NRC issued an SE for NMP2 response to GL 96-05, and stated that NMP2 had established an acceptable program to periodically verify the design-basis capability of safety related MOVs. In a letter dated May 17, 1999 (Accession Number 9905250245), the NRC attached the SE for NMP2 response to GL 95-07, and stated that NMP2 had taken appropriate corrective actions to ensure that MOVs determined to be susceptible to pressure locking or thermal binding are capable of performing their intended safety functions. In its request for the EPU license amendment, the licensee described its evaluation of the MOVs within the scope of GL 89-10 and GL 96-05 for the effects of the proposed EPU, including those related to pressure locking and thermal binding as addressed in GL 95-07. While the operating conditions for certain MOVs will change due to EPU, the licensee's review of affected systems indicates that the existing maximum operating conditions (e.g., flow rates, pressures and temperatures) remain valid for the EPU. The minor impact to normal operating and DBA temperatures due to EPU does not require a change to the temperature assumptions used in MOV voltage drop calculations. Therefore, no changes were identified to the design functional requirements for all GL 89-10 and GL 96-05 MOVs. All MOVs will perform their safety related function under EPU conditions without requiring any physical changes to the valves. The MOVs were also evaluated for pressure locking and thermal binding under EPU conditions, and no MOVs were determined to be susceptible to pressure locking or thermal binding as a result of EPU.

The licensee has a program to ensure that safety related AOVs are selected, set, tested and maintained so that AOVs will operate under normal, abnormal, or emergency operating design basis conditions. Lessons learned from the MOV program were applied to other safety related power-operated valves, such as AOVs. Elements of the MOV program applied to the AOV program include documentation of the design basis operating requirements for the valve and adequacy of the actuator to meet those requirements; establishment and control of set-up criteria; and periodic testing. The Reactor Building Closed Loop Cooling, Containment Purge, Standby Gas Treatment, Reactor Core Isolation Cooling, Control Rod Drive, Residual Heat Removal, Spent Fuel Pooling Cooling and Service Water systems contain safety related AOVs. The results of the licensee's evaluation show that the EPU does not affect the maximum differential pressures, flow rates, or fluid temperatures under normal, abnormal, or emergency operating design basis conditions. Therefore, the EPU has no impact on associated 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 EPU. As such, no changes in the pump head performance are required for the affected safety related pumps at EPU conditions. The High Pressure Core Spray, Low Pressure Core Spray, Emergency Diesel Generator (EDG) Fuel Oil, EDG Lubricating Oil, EDG Jacket Cooling Water, Control Building Heating, Ventilation, and Air Conditioning, Reactor Core Isolation Cooling, Residual Heat Removal, Spent Fuel Pool Cooling, Standby Liquid Control (SLC), and Service Water systems contain safety related pumps. The results of the evaluation show that the EPU does not affect pump performance under normal, abnormal, or emergency operating design-basis conditions.

The licensee's review indicates that existing safety and relief valve set pressures remain valid for the EPU. Reactor pressure will increase following the limiting anticipated transient without a scram (ATWS) event under EPU conditions which results in a minimal margin between the SLC pump discharge relief valve set pressure and reactor vessel pressure. By letter dated February 19, 2010 (ML100550601), the licensee responded to an NRC staff RAI (RAI G3) stating that the SLC pump discharge piping design pressure will be rerated to a higher pressure (1600 psig); and the SLC pump discharge relief valve set pressure will be increased to provide adequate margin. This modification was completed during the NMP2 2010 refueling outage (ML112450479).

In its submittal (Reference 1), the licensee described its review of the IST program for safety related pumps and valves for EPU operations. Valves in the IST program include MOVs, AOVs, check valves, pressure relief valves and thermal relief valves. The current Code of Record is the 2004 Edition of the ASME OM Code. NMP2 TS 5.5.6, "In-Service Testing Program," states that this program provides control for IST of ASME Code Class 1, 2, and 3 valves and pumps. The IST Program assesses the operational readiness of valves and pumps within the scope of the ASME OM Code. The scope of the IST Program and testing frequencies will not be affected by the EPU.

Conclusion

The NRC staff has reviewed the licensee's assessments related to the functional performance of safety related valves and pumps in support of the EPU license amendment request. The EPU has no adverse impact on valve and pump performance. The modification to rerate SLC pump discharge piping to a higher pressure and increase the relief valve set pressure ensures that the discharge relief valve for each SLC pump will not prematurely lift during an ATWS event. The staff has determined that the licensee adequately addressed the effects of the EPU on safety related valves and pumps, and that the scope IST Program will remain the same under the EPU. The staff further concludes that the licensee has adequately evaluated the effects of the EPU on its MOV programs related to GL 89-10, GL-96-05, and GL 95-07, and considered the lessons learned from those programs to other safety related AOVs. Therefore, the staff concludes that the licensee has demonstrated that safety related valves and pumps will continue to meet the requirements of GDC-1, 37, 40, 43, 46, and 54, and 10 CFR 50.55a(f) following implementation of the proposed EPU at NMP2. As a result, the NRC staff finds the EPU to be 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 CPPU on the qualification of the equipment to withstand seismic events and the dynamic effects associated with pipe-whip and jet impingement forces. The primary input motions due to the safe shutdown earthquake (SSE) are not affected by a CPPU.

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

The licensee evaluated safety related SSCs subject to CPPU conditions. Seismic loads are not affected by power uprates. The licensee has considered DBA LOCA conditions, main steam line break (MSLB) and other HELBs that could affect safety related mechanical and electrical equipment and components. In Section 2.2.1 of this SE, the staff's review of the licensee's evaluations has shown that SSCs important to safety are adequately protected from the dynamic affects of postulated pipe failures, including pipe whip and jet impingement, at EPU conditions. As shown in the staff's input in Sections 2.2.1 and 2.2.2 of this SE, containment hydrodynamic inertia loads due to DBA LOCA and SRV discharge are not affected by the proposed EPU. The licensee's evaluation of containment hydrodynamic loads, which also shows that these loads are not affected by the EPU, is presented in PUSAR Section 2.6.1.2.

The licensee's evaluation for the qualification of safety related electrical equipment subject to DBA LOCA conditions, MSLB and other HELBs is documented in PUSAR Section 2.3.1. The licensee noted that normal temperature, pressure, and humidity conditions do not change due to EPU. The licensee has also indicated that the design limits currently used for the environmental qualification evaluations of safety related electrical equipment bound those of EPU conditions. The licensee also evaluated safety related mechanical equipment subject to increased fluid-induced loads, nozzle loads and component support loads due to increased temperatures, flows or pressures for EPU. The staff's review of the licensee's evaluations finds that the mechanical components and component supports are adequately designed for the proposed EPU conditions (see Section 2.2.2 of this SE). In its responses to staff RAIs, the licensee indicated that EPU effects on safety related mechanical and electrical equipment, including their nonmetallic components, have been addressed within the NMP2 electrical and mechanical equipment environmental qualification programs, described in USAR Section 3.11, and that the dynamic qualification of safety related electrical and mechanical equipment has not been impacted by the proposed EPU.

Based on the review above, the NRC staff concludes that the original seismic and dynamic qualification of safety related mechanical and electrical equipment for NMP2 is not affected by the proposed EPU.

Conclusion

The NRC staff has reviewed the licensee's evaluations of the effects of the proposed EPU on the seismic and dynamic qualification of mechanical and electrical equipment and concludes that the licensee has (1) adequately addressed the effects of the proposed CPPU 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 EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the seismic and dynamic qualification of the mechanical and electrical equipment.

2.2.6 Evaluation of Steam Dryer Integrity

Regulatory Evaluation

Plant operation at EPU conditions can result in adverse flow effects on the main steam (MS), feedwater (FW), and condensate systems and their components (including the steam dryers in BWR plants) from increased system flow and flow-induced vibration. Some plant components, such as the steam dryer, do not perform a safety function, but must retain their structural integrity to avoid the generation of loose parts that might adversely impact the capability of other plant equipment to perform their safety functions. The NRC staff reviewed the evaluation by NMPNS of the potential adverse flow effects for the proposed EPU license amendment at NMP2, including consideration of the design input parameters and the design-basis loads and load combinations for the NMP2 steam dryer for normal operation, upset, emergency, and faulted conditions. The NRC staff's review covered the analytical methodologies, assumptions, and computer modeling used in the evaluation of the NMP2 steam dryer. The NRC staff's review also included a comparison of the resulting stresses against the applicable limits.

The NRC staff reviewed the licensee's evaluation of the MS, FW, and condensate system components at NMP2 for potential susceptibility to adverse flow effects from EPU operation. The NRC's acceptance criteria are based on the GDC in Appendix A, "General Design Criteria for Nuclear Power Plants," to Part 50 in Title 10 of the *Code of Federal Regulations* (10 CFR 50), including (1) GDC 1, insofar as it requires those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences 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 those systems and components which are essential to the prevention of accidents which could affect the public health and safety or to mitigation of their consequences be designed to withstand the effects of earthquakes combined with the effects of normal or accident conditions; and (3) GDCs 40 and 42, insofar as they require that protection be provided for engineered safety features (ESFs) against the dynamic effects and missiles that might result from plant equipment failures, as well as the effects of a LOCA. NRC SRP Sections 3.9.1, 3.9.2, 3.9.3, and 3.9.5 contain the specific review criteria.

Technical Evaluation

2.2.6.1 Steam Dryer

The original NMP2 steam dryer is similar to an upgraded BWR 4/5 curved hood design and includes perforated plates placed at the inlet and outlet sides of the vane banks in order to distribute the steam flow uniformly through the vane banks. In comparison to other nuclear power plants that have received EPU license amendments, the NMP2 main steam line (MSL) flow velocities are as much as 5 percent higher than corresponding velocities in the Vermont Yankee Nuclear Power Plant, which received an EPU license amendment in 2006. The original licensed thermal power (OLTP) steam velocity at NMP2 is 143 feet-per second (ft/sec) and the predicted EPU (120 percent OLTP) steam velocity is 177 ft/sec. For comparison, the steam flow velocity in the MSLs at EPU conditions for Susquehanna is 153 ft/sec, and for Hope Creek it is 167 ft/sec. These velocities are lower than the corresponding velocities at QC2 2 (168 ft/sec at OLTP and 202 ft/sec at EPU).

NMPNS summarized its assessment of the original NMP2 steam dryer stresses at EPU conditions in Attachment 13 –Steam Dryer Evaluation, in the letter to USNRC dated May 27, 2009 ([1] or Reference 1). Attachment 13.3 (CDI Report 08-13P) uses the analytical techniques described in Section 3 of BWRVIP-182 and Section 4 of BWRVIP-194 to assess the potential for MSL acoustic excitation at EPU [1]. The assessment results show that the onset for SRV standpipe resonance would be at greater than 45 percent above the EPU power level, which meets the BWRVIP-182 screening for exclusion of SRV standpipe resonance. This exclusion was validated by subscale testing as suggested in BWRVIP-194. Attachment 13.2 (CDI Report 08-08P, Rev. 2) follows the BWRVIP-194 guidelines and applies an earlier version of the ACM model documented in the CDI Report 07-09P, Rev. 0 for determining the pressure loads on the steam dryer at CLTP using the MSL strain gauge measurements at CLTP [1]. The scaling of the CLTP flow induced vibration (FIV) pressure loading to EPU is performed based on velocity-squared scaling for the full frequency range. NMPNS follows the methodology described in BWRVIP-194 for determining stresses in the dryer at CLTP and EPU conditions. The stress results for the NMP2 steam dryer are presented in Attachment 13.1 (CDI Report 08-24P) [1].

The stress analysis results identified four groups of areas that require reinforcement of selected welds to meet the recommendation for the minimum alternating stress ratio of 2.0. The minimum alternating stress ratio is defined as the ratio of the allowable fatigue limit to the maximum calculated alternating stress intensity in the steam dryer at EPU conditions. The maximum allowable fatigue limit is 13600 psi for stainless steel at 10^{11} cycles. NMPNS applied detailed submodeling to evaluate these reinforcements and demonstrated that the stresses at these locations also meet the minimum alternating stress criteria. These reinforcements are listed later in the report as Group 1, 2, 3, and 4 modifications.

In Attachment 13, NMPNS refers repeatedly to the BWRVIP-194 Report (BWR Vessel and Internals Project, Methodologies for Demonstrating Steam Dryer Integrity for Power Uprate) [1]. The licensee also states that the NMP2 steam dryer integrity analysis is in accordance with the guidelines outlined in the BWRVIP-194 Report. However, this report has neither been reviewed nor approved by the NRC staff. Therefore, the licensee was requested to omit references to BWRVIP-194 in its application, and to include necessary technical justification in the EPU application itself instead of referring to BWRVIP-194. The licensee has omitted any reference to BWRVIP-194 in the subsequent submittals as requested.

2.2.6.1.1 Steam Dryer Cracking

In Attachment 13.5, "Flaw Evaluation and Vibration Assessment of the Nine Mile Point Unit 2 Steam Dryer for Extended Power Uprate Operating Conditions," 2009, NMPNS states that several reportable indications were identified during the in-vessel visual inspection of the NMP2 steam dryer during the spring 2008, RF011 outage [Reference 1]. The indications were observed in the upper support ring, the drain channel to skirt weld, and in the tie bar-to-hood weld heat affected zone. The indications in the upper support ring were attributed to IGSCC driven by the residual stresses induced in the material during the cold forming process. These stresses are relieved as the crack is formed and they do not drive further growth. The evaluation concludes that the fatigue crack growth (FCG) would be negligible considering the low range of alternating stresses in the upper support ring. The flaw in the drain channel to skirt vertical weld is oriented perpendicular to the weld and the heat-affected zone and has characteristics of a fatigue crack.

The evaluation results show that the expected FCG is minimal. The evaluation results for the upper support ring cracking and the drain channel cracking is supported by the field experience from the operating fleet in which such cracking has existed for many years without exhibiting continuous growth. The indications in the tie bar-to-hood welds were attributed to intergranular stress corrosion cracking (IGSCC). These indications were observed earlier in 2004 and have been monitored without any observed crack growth. As a follow-up, all these indications will be inspected during the next refueling outage to identify any additional crack growth.

In Attachment 11, "Flaw Evaluation of Indications in the Nine Mile Point Unit 2 Steam Dryer Vertical Support Plates Considering Extended Power Uprate Flow Induced Vibration Loading," of NMPNS' letter dated July 30, 2010, NMPNS reports indications (< 2.0-in. long) in the NMP2 steam dryer vertical support plates identified during the April 2010 refueling outage steam dryer visual examination [5]. These indications were not identified during the earlier inspections of the dryer. These indications are within the weld material and they lack branching in the flaws; this suggests that the cracks are not caused by IGSCC. Since multiple load paths exist in the steam dryer structure, the evaluation assumes that the vertical plate would be subject to relatively constant displacement loading. Based on this assumption, the evaluation results show that the crack initiated at the outer hood vertical support plate at CLTP conditions is expected to grow to a length of approximately 2-3 in. at EPU conditions before being arrested. This additional growth would occur in the first few months of EPU operation. These indications will also be inspected during the next refueling outage.

2.2.6.1.2 Modifications for Existing Dryer

Per its LAR and additional supplemental letters, NMPNS will make several structural modifications to the NMP2 steam dryer so that the resulting dryer stresses satisfy the recommended EPU margin (minimum alternating stress intensity ratio > 2.0). These modifications are described in Attachment 7 – Stress Evaluation of Nine Mile Point Unit 2 Steam Dryer Using ACM Rev. 4.1 Acoustic Loads (CDI Report No. 11-04P), to the Letter from M. A. Philippon to USNRC dated June 13, 2011 [9]. These modifications are divided into four groups:

Group 1: The lifting rod bracket/side plate welds: Reinforcement plates welded to the vertical plate and the weld size increased from 1/4" to 1/2".

Group 2: The middle hood reinforcement strip: A 1/8" thick curved plate is overlaid over the portion of the middle hood outboard of the closure plate.

Group 3: The inner hood/hood support welds: A total of four 15 lb. masses are placed on the central hood panels.

Group 4: A collection of locations:

(a) Middle hood/hood support welds. A total of four 10 lb. masses are placed on the central portion of the middle hood.

(b) Bottom of the drain channel/skirt welds. These welds are reinforced by thickening the length and wrapping the weld around the junction terminus and continuing it for 1" along the interior side.

(c) Outer hood/hood support/cover plate junctions. A stress relief cut-out hole is added to the support plate.

In addition to the above modifications, stiffening strips are added to the closure plates to lower the stresses to an acceptable level.

For the NMP2 dryer stress analyses, NMPNS uses strain gauge measurements to determine acoustic pressure in the main steam lines (MSLs), employs the newly developed acoustic circuit model (ACM, Rev. 4.1) for estimating steam dryer loading and the frequency domain approach for calculating stresses, and uses embedded finite element models for determining stresses at high stress locations in the dryer. Appropriate bias errors and uncertainties are applied throughout the analyses. NMPNS has also demonstrated by analyses and scale model tests that a standpipe resonance will not be present during power ascension to EPU. Therefore, a frequency-independent bump-up factor (BUF), based on the square of the flow velocity, is applied to the hydrodynamic pressure loads on the steam dryer at CLTP to estimate the corresponding loads at EPU. These topics are summarized below.

2.2.6.1.3 Main Steam Line Instrumentation

To measure acoustic pulsations within the MSLs, NMPNS has instrumented NMP2 MSLs with strain gauges at eight locations, which includes two locations on each of the four MSLs, with eight equally spaced, circumferentially oriented strain gauges at each location. These strain gauges measure the hoop strain that is used to obtain the acoustic pressure inside the MSL. The hoop strain is also influenced by bending strains within the MSLs. In order to minimize the bending effects on the measured strains (which are unrelated to the acoustic pressures), the strain gauge pairs are connected to a Wheatstone bridge in a half bridge configuration, such that the signals from the individual strain gauges are additive, resulting in the cancellation of the bending strain and enhancement of the hoop strain sensitivity. For each MSL location, the four signals are averaged to further minimize the bending error and improve the signal to noise ratio.

The NRC staff made an observation about the NMP2 MSL instrumentation. The MSL strain gauges are located at different distances from the MSL inlet nozzle as compared to the locations in the other plants. Table 2.1 of CDI Report No. 08-08P, Rev. 3, "Acoustic and Low Frequency Hydrodynamic Loads at CLTP Power Level on Nine Mile Point Unit 2 Steam Dryer to 250 Hz," dated December 2009, indicates that the distance between the upper and lower strain gauge locations on each main steam line is about 13 ft. for line A and about 5 ft. for lines B, C & D [Attachment 14, Reference 3]. These distances are significantly shorter than those used in other plants, e.g., ~32 ft. for Quad Cities Unit 2 (QC2), 36 ft. for Hope Creek (HC1), 25 ft. for Browns Ferry Unit 1 (BFN1), and 32 ft. for Monticello. In RAI NMP2-EMCB-SD-RAI-10, the NRC staff requested that NMPS provide the (1) reasons for these shorter distances, (2) the associated location uncertainty, and (3) the effects of using a non-symmetric distribution of the strain gauges on the four main steam lines.

The licensee responded to RAI NMP2-EMCB-SD-RAI-10 in Attachment 3 of the letter to NRC dated May 7, 2010 [4], stating that the locations of the strain gauges were limited because of restricted access in the NMP2 drywell (Mark II containment design) and because of the main steam line whip restraints and snubbers. [[

]].

In addition, NMPNS discussed the location uncertainty associated with the placement of strain gauges at NMP2. Even though the strain gauge locations at NMP2 were optimized as discussed, they were not optimized for the QC2 benchmarking. Therefore, NMPNS determines the strain gauge position error so as to be consistent with the similar error previously determined for Vermont Yankee and subsequently applied to the Hope Creek submittal, as well as in the submittals for Browns Ferry and Monticello. For the strain gauge arrangement used in NMP2, the position uncertainty error is 19.52 percent, as shown in Table 5.2 of the NMP2 loads report, CDI Report No. 08-08P [Attachment 14, Reference 3]. Finally, NMPNS explained that there is no restriction on the locations where data are collected with regard to the ACM model.
[[

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The NRC staff finds the licensee's approach in optimizing the strain gauge locations reasonable and acceptable because the licensee accounted for the strain gauge position uncertainty in the dryer stress analysis.

The details of the MSL strain gauge data reduction procedure are given in SIA Calculation No. NMP-26Q-302 (Attachment 13.4, Reference 1). It is stated in this document that 14 of the 64 MSL strain gauges used to measure the CLTP data in the NMP2 plant failed during the April 2008 MSL strain gauge data collection. The licensee was, therefore, requested in an RAI to elaborate on any plans to repair those strain gauges and also to address the minimum number of strain gauges required, including their circumferential locations, for estimating the acoustic pressure loads on steam dryer during power ascension.

In Attachment 3 of the NMPNS letter dated May 7, 2010, the licensee responded by stating that the failed strain gauges were replaced in the spring of 2010 [4]. The minimum number of strain gauges is two pairs (four strain gauges) per location. However, the licensee plans to maintain the maximum number of strain gauges to the extent practical. The additional pairs of strain gauges allow for redundancy and assist in reducing the effects of bending vibration of the MSLs, such that the measured hoop strain is predominantly due to dynamic pressure changes inside the pipe. The licensee planned to install eight strain gauges at each MSL location. The strain gauge pairs are ideally located 90° apart for optimum cancellation of bending modes. The NRC staff finds this response acceptable because the licensee plans to maintain up to 8 strain gauges at each measurement location to allow for sufficient redundancy.

Further review of the data reduction procedure, as presented in SIA Calculation No. NMP-26Q-302, indicates that the Electrical Interference Check (EIC) signals were recorded for all strain gauges. The licensee was requested to clarify whether or not the EIC signals were filtered out from the strain gauge data as given in Figures 1 to 10, and the subsequent spectra and waterfall plots of the same report.

In Attachment 3 of the NMPNS letter dated May 7, 2010, the licensee responded to the NRC staff's RAI stating that the EIC signals were used to identify the frequencies that are purely electrical in nature [4]. The licensee further stated that these frequencies were filtered out from the strain gauge data provided in Figures 1 through 10 and the subsequent spectra and waterfall plots. The licensee further noted that the frequencies listed in Table 4 of the calculation document, plus 60 Hz and its multiples, were filtered out from the data presented in SI Calculation No. NMP-26Q-302 [Attachment 13.4, Reference 1]. Based on a review of the licensee's response, the NRC staff finds the response acceptable because the licensee adequately addressed that the signals were filtered out from the strain gauge data. The NRC staff's question about filtering the strain gauge signals and using them to estimate the dryer load from the ACM code is addressed in SE Section 2.2.6.1.5.

2.2.6.1.4 <u>Exclusion of Standpipe Resonance</u>

Attachment 13.3 (CDI Report 08-13P) discusses the analytical techniques and Scale Model Tests (SMT) to assess the potential for MSL acoustic excitation at EPU [1]. The licensee tested a nominal one eighth scale model of the complete four main steam lines at NMP2, including a model of the steam dome and a simplified dryer model. As in previous EPU applications, the objectives were to identify the Mach numbers at which the acoustic resonances in the SRV standpipes are initiated and to develop a BUF for use in estimating the dynamic loading on the steam dryer at EPU conditions from in-plant measurements at CLTP conditions. The scale model did not include the branch pipes of RCIC because in-plant measurements of previously reviewed BWR plants indicated that long, small-diameter pipes did not generate any acoustic resonance in the steam piping.

The NRC staff noted that the pressure vessel used to simulate the reactor dome is the same vessel used in previous SMT of other BWR plants. However, the piping system is dimensioned specifically for NMP2. Since it was not clear how the new pipes are fitted into the exit nozzles of the existing pressure vessel, the licensee was requested in NMP2-EMCB-SD-RAI-15, to explain whether or not the scale model geometry at the main steam line inlet is identical to that for NMP2. In particular, the licensee was requested to clarify if the scale model has any pipe reducers or expansions fitted at the RPV steam outlet nozzles or MSL pipe inlets and to discuss the effect of any differences from the plant geometry on the results.

The licensee provided its response in Attachment 3 of its letter from dated May 7, 2010, and confirmed that the same pressure vessel is used in all previous SMTs of other plants [Ref. 4]. However, the diameter of the subscale steam lines is selected to match the investigated plant geometry. For NMP2, the main steam lines were represented by 3-inch PVC piping, while the QC2 main steam lines were represented by 2½-inch PVC piping. To accommodate this difference in PVC pipe diameter, a second set of main steam line nozzles was fabricated on the subscale steam dome, one set to accommodate the 2½-inch PVC piping and the other to accommodate the 3-inch PVC piping. The unused nozzles were capped and each space was filled with a solid piece of PVC. Therefore, the scale model geometry is similar to the plant geometry of NMP2 and does not include reducer or expansion sections fitted at the MSL inlets of the SMT. Thus, the licensee's response confirmed that the scale model design at the MSL inlets is similar in geometry to NMP2, and therefore, the NRC staff's question regarding the scale model geometry is satisfactorily addressed.

The NRC staff also noted that the standpipes in the scale model were made shorter than those of NMP2. This difference resulted in an increase of only a few percent in the resonance frequency (4.5 percent). It was not clear, however, whether all the standpipes have the same length or not, and whether the standpipes of the scale model represent an accurate geometrical replica of the full scale standpipes at NMP2. In a NRC staff's RAI, the licensee was requested to provide a comparison between the standpipe geometries in the scale model and the full size plant, and explain the effect of any geometrical differences on the SMT results, including the BUF used to scale up or project the CLTP results for EPU conditions.

The licensee responded to the NRC staff's request in Attachment 3 of its letter dated May 7, 2010, stating that the standpipes in NMP2 do not have the same length (it varies from [[ ]) [4]. In the SMT, all standpipes were made of the same length, corresponding to the shortest one in NMP2 [[ ]]. Although the subscale standpipe lengths are not identical to those of NMP2, this deviation in the SMT geometry is acceptable because all the subscale standpipes have the same acoustic resonance frequency and, therefore, if acoustic resonance is an issue, it would be stronger in the SMT rather than at NMP2, whose standpipes have different lengths. Since the deviation in the subscale standpipe length is only 4.5 percent and its effect on the resonance intensity is conservative, the NRC staff's RAI regarding this deviation is satisfactorily addressed.

At the CLTP and EPU conditions, the steam flow Mach number in the MSLs is 0.0933 and 0.1099, respectively. The scale model tests were performed up to a Mach number of approximately [[ ]], which is [[ ]] higher than the EPU Mach number. In total, 14 pressure transducers were used to measure the pressure fluctuation in the MSLs and the SRV standpipes. During the tests, acoustic resonance in the SRV standpipes was not initiated up to the highest tested Mach number. Therefore, the Mach number at EPU conditions (M=0.1099) is substantially lower than that corresponding to the onset of the SRV resonance [[ ]]. Power spectral densities (PSDs) of the acoustic pressure are given in the appendix of CDI Report 08-13P, Rev. 1 (Attachment 13.3, Reference 1) for all measurement locations and all test conditions.

A frequency-dependent BUF was developed by the licensee for each strain gauge location. This BUF is obtained by dividing the EPU PSD at each frequency by the CLTP PSD at that frequency, and then taking the square root. The resulting BUFs for the 8 strain gauges, given in Fig. 9.1 of CDI Report No. 08-13P, Rev. 1, show fluctuations between [[ ]] and therefore the mean value was not readily apparent [Reference 1]. The licensee was requested to superimpose onto Fig. 9.1, the mean value of the BUF, as a function of frequency. For frequencies where the BUFs are not larger than the square of the velocity ratio, the licensee was requested to ensure that the steam dryer stress analysis utilizes a minimum BUF based on velocity-square ratio. For frequencies with the BUF larger than the square of the velocity ratio, the licensee was requested to ensure that the steam dryer stress analysis utilizes the corresponding BUFs.

The licensee responded to NRC staff's request in Attachment 3 of its letter dated May 7, 2010 [Reference 4]. In its response, Fig. 9.1 of CDI Report No. 08-13P, Rev 1, was reproduced. The figure included a mean value of [[ ]] for the measured BUF, which is larger than the velocity-squared factor of [[ ]] used by CDI in the dryer stress analysis at EPU. The licensee rationalized that since the acoustic resonance of the SRV standpipes is not expected to occur at EPU, and therefore it is appropriate to use the velocity-squared factor as the BUF. To substantiate this position, the licensee referred to TR BWRVIP-182, which includes a flow chart that provides guidance with regards to screening for acoustic resonance conditions and for pressure measurements in the literature taken on surfaces exposed to turbulent boundary layers. The flow in the reactor dome, however, includes turbulent free jets issuing from the dryer vanes, separated flow over the dryer sides, and swirl flow at the steam lines inlets. These flow types are much more complex than turbulent flow along a plate. In addition, the measured mean value of the BUF is consistently higher than the velocity-squared factor over the whole frequency range of interest (0-250 Hz). The licensee was requested by the NRC staff to use the measured mean value of the BUF [[ ]] in the dryer stress analysis at EPU conditions.

The licensee responded in Attachment 4 of its letter dated November 5, 2010, stating that the computed BUF from the SMT data was based on a Mach number in the MSL of [[ ]], whereas the EPU Mach number at NMP2 is 0.1099 [Reference 7]. This explained the reason that the BUF obtained from SMT [[ ]] is higher than the velocity-squared ratio [[ ]]. The licensee further substantiated that the most representative BUF should be based on interpolated subscale test data so that the CLTP and EPU Mach numbers correspond with those expected at full scale for NPMP2. A linear interpolation of the SMT data results in an average BUF of

[[ ]] compared to the velocity-squared ratio of [[ ]] used in the EPU analysis. The NRC staff also finds the use of BUF based on a velocity-square relationship, acceptable for plants that do not experience standpipe resonances up to EPU, because the scale model test results as well as measurements during power ascension to EPU for two plants that recently implemented EPU has confirmed such relationship. In addition, the measurements at NMP2 from 75% to 100% CLTP have verified the appropriateness of the velocity-square relationship [Reference 56]. As further assurance, the NRC staff is placing a license condition to confirm the velocity-square relationship at various power plateaus above CLTP and up to EPU during power ascension.

The NRC staff finds the licensee's rationale and justification acceptable and agrees that the use of a BUF of [[ ]] is reasonable.

2.2.6.1.5 Acoustic Circuit Model (ACM) Revision 4.1

To estimate the loading on the steam dryer, the licensee applies the MSL strain gauge data to the acoustic models of the NMP2 MSLs and RPV steam space using CDI's Acoustic Circuit Model (ACM). Several versions of the ACM have been documented, and the latest version, Rev. 4.1 (CDI Report No. 10-09P, "ACM Rev. 4.1: Methodology to predict full-scale steam dryer loads from in-plant measurements," Rev. 2), was used to compute the loads on the NMP dryer. These loads include [[

]] on each MSL. Those amplitudes are then used to determine the fluctuating acoustic pressure distribution within the RPV and on the dryer surfaces. For the low-frequency hydrodynamic components, [[

]].

These pressure time histories, as discussed in Section 2.2.6.1.7, are modified by considering the appropriate bias errors and uncertainties, and then applied to the structural Finite Element (FE) models of the dryer to compute alternating stresses. The ACM bias errors and uncertainties are based on benchmarking against data acquired from the QC2 plant with the instrumented steam dryer, prior to the installation of the Acoustic Side Branch (ASB) devices that eliminated strong tonal loads in the steam valve standoff pipes, which damaged the QC2 steam dryer.

NMPNS' original submission used an earlier version of the ACM, as documented in CDI Report 07-09P Rev. 0, to estimate their dryer loads [Enclosure 3, Reference 10]. Later, as part of a project with the Boiling Water Reactor Vessel and Internals Project (BWRVIP), CDI developed a new version of the ACM, Version 4.0, which adjusted the modeling parameters to improve agreement with instrumented dryer benchmarking data from the QC2 BWR. However, the ACM 4.0 procedure, when applied to other BWR plants, performed two subtractions which reduced the amplitudes of the MSL strain gauge signals prior to computing dryer loads: subtraction of the electrical interference (EIC) signals measured at low input voltage conditions, and subtraction of the signals acquired at low MSL flow rates.

Since the dryer loading bias errors and uncertainties were computed based on the QC2 benchmark, where the MSL signals were not reduced to account for EIC or low flow background noise, the NRC staff determined that it is unacceptable and non-conservative to use the signal reduction techniques on the NMP2 dryer. By using bias errors and uncertainties based on higher, non-filtered MSL signals from the QC2 benchmark on dryer loads computed using lower, filtered NMP2 MSL signals, the dryer stresses are underestimated. Therefore, the NRC staff requested additional information from NMPNS to address these inconsistencies between the benchmarking and the application to the NMP2 dryer.

In response to these RAIs, the licensee modified the ACM, to Version 4.1 [Attachment 7, Reference 8]. The MSL data from the QC2 and NMP2 plants are now processed identically, so that the ACM bias errors and uncertainties derived from the QC2 benchmark are applicable to the NMP2 dryer loads. Specifically, in-plant MSL measurements are filtered to remove signals at discrete electrical frequencies, vane passing frequencies from recirculation pump(s) are removed, and the MSL strain gauge signals are [[

]].

[[

]] thus, addressing the NRC staff's RAI, [Attachment 8, Reference 5], or low power data from the CLTP MSL measurements. The NRC staff finds that this is now consistent with the benchmarking of ACM Version 4.1, and acceptable.

The final filtered NMP2 MSL data, while slightly lower than the raw data, does not appear to be unrealistically reduced by the filtering process. It is noted that the NMP2 dryer loads are also much lower than those which caused dryer failures in the QC plants prior to the installation of the ASBs. Because the updated NMP2 dryer data has been computed in a manner consistent with that used to benchmark the ACM 4.1, the NRC staff finds the alternating loads applied to the NMP2 dryer to be acceptable [Attachment 8, Reference 8].

2.2.6.1.6 <u>Bias and Uncertainties in Hydrodynamic Loads</u>

In the ACM Rev. 4.1 report, the licensee cites updated frequency-dependent bias errors and uncertainties based on their new MSL data processing procedure described in the preceding section. These bias errors and uncertainties are applied to dryer loads, increasing or decreasing the loads based on the benchmarking (see Table 8.2 of the report for a final list of increases to be applied to the NMP2 dryer loads). The licensee has updated the algorithm used to determine the bias errors and uncertainties based on the QC2 instrumented dryer data. Previously, CDI computed bias errors and uncertainties over six groups of dryer sensors, and then averaged the group results to compute single values for the entire dryer. Currently, CDI simply averages bias errors and uncertainties over all 16 dryer sensors, which produces more conservative values than the old grouping approach. The NRC staff finds this new approach acceptable because the updated values are more conservative.

CDI provided a comparison of old and updated (ACM Rev. 4.0) bias errors and uncertainties in Section 7 of the ACM Rev. 4.1 Report [Attachment 7, Reference 8]. The uncertainties change slightly, and are higher or lower over different frequency ranges. Since the ACM 4.1 dryer loads are generally slightly lower, the bias errors increase over several frequency bands (leading to increased dryer loads when applied to the NMP2 data). The only important exception is for tonal loads induced by resonances in MSL valve standoff pipes, such as those which occurred in the QC plants prior to the installation of the ASBs. Here, the licensee claims that the bias errors for tonal loads due to valve [[

]]. The NRC staff did not agree with this change in bias error for tonal loads caused by valve resonance. Because no valve resonances are expected at NMP2 at EPU conditions, this issue does not affect NMP2. Therefore, for the application of the NMP2 steam dryer, only, the NRC staff accepts the updated bias errors and uncertainties for ACM 4.1 over all other frequency ranges.

2.2.6.1.7 Dryer Stress Analysis

NMPNS employs a computationally efficient stress analysis approach for calculating the transient stress response of the NMP2 steam dryer to pressure fluctuations in the steam dome. This approach was previously used by PSEG in the stress analysis of the Hope Creek steam dryer stress analysis under EPU conditions, and found to be acceptable. The traditional direct time-history analysis requires long computation times and includes the transient solution associated with inaccurate initial conditions (typically, zero displacement and velocity), while the approach based on harmonic analysis conducted in the frequency domain allows for applying specified damping (one percent of the critical modal damping) for the whole range of the natural frequencies of the steam dryer. This approach introduces an average bias error of [[

]], and is considered in the NMP2 evaluations.

Prior to performing the stress analysis of the dryer, NMPNS modifies the hydrodynamic loads as calculated by the use of ACM 4.1 and discussed in Section 2.2.6.1.5, by applying the following bias errors and uncertainties [Attachment 5, Reference 13]:

(1) frequency-dependent bias errors and uncertainties associated with Rev. 4.1 of the ACM,

(2) uncertainties associated with the MSL pressure measurements and strain gauge locations, and with the pressure measurements on the QC2 steam dryer,

(3) [[ ]],

(4) bias error and uncertainties introduced by the finite element analysis, which include:

(i) [[

]]

(ii) [[

]].

NMPNS applies a weld factor of 1.8 to all fillet weld locations and 1.4 to all full penetration welds in calculating the alternating stress intensities to the results of the finite element stress analysis.

2.2.6.1.7.1 [[ ]] – Hydrodynamic Damping

The hydrodynamic damping methodology, due to energy losses associated with the steam flow [[ ]], was initially proposed for use in TVA's Browns Ferry Nuclear (BFN), Units 1, 2, and 3 EPU application (ML072130456). By NMPNS' letter dated May 27, 2009 [Reference 1], the licensee proposed the same [[ ]] damping methodology that was used for TVA's steam dryer analyses. It is noted that the NMP2 steam dryer design is similar to that of BFN and includes perforated plates that are placed at the inlet and outlet sides of the vane banks in order to distribute the steam flow uniformly through the vane banks. Details of the NRC staff's assessment are provided below.

The NMP2 steam dryer design includes perforated plates placed at the inlet and outlet sides of the vane banks in order to distribute the steam flow uniformly through the vane banks. The perforated plates have varying amounts of open areas at different elevations, [[

]]. The experimental and analytical work for determining the damping ratio was performed by TVA while the NRC staff was reviewing the EPU application for the BFN1 steam dryer. The NRC staff's assessment of this is summarized below.

[[

]].

[[

]].

The NRC staff requested additional information about the tests performed by TVA for estimating the damping [[ ]]. In response to the NRC staff's RAIs, TVA presented the analysis of bias and uncertainty errors in the alternating stress ratio resulting from the errors in measuring the loss coefficient in the tests as shown in Enclosure 1 attached to the letter dated March 6, 2008 [Reference 11]. [[

]].

[[

]].

In its response to the RAI, TVA also informed the NRC staff that only 50 percent of the previously used value for [[ ]] will be credited in subsequent analysis in order to lessen the reliance of the stress margin on [[ ]].

[[

]].

The NRC staff sought additional information about the location and amplitude level of [[

]]. In response to the NRC staff's RAI (as noted in Enclosure 1 attached to the letter dated June 16, 2008 [Reference 12]), TVA stated that [[

]].

NMPNS uses the same approach, which was discussed above, to account for the [[

]]. It was also noted that in the stress analysis of the NMP2 steam dryer reported in Attachment 7 [Reference 9], NMPNS uses [[

]]. Since the flow [[

]], the NRC staff finds the proposed methodology acceptable for NMP2.

2.2.6.1.7.2 <u>Use of Submodels [[ ]]</u>

The dryer analyzed in Section 5 of C.D.I. Report No. 10-11P identified several locations with alternating stress ratios below the recommended EPU target value of 2.0, when subjected to the ACM Rev. 4.1 acoustic loads [Attachment 11, Reference 5]. These locations are divided into four separate groups (Group 1 to 4) as listed in Sections 2.2.6.1.2, along with the proposed modifications to achieve the desired EPU stress margins. These modifications were evaluated in the same report using a combination of sub-modeling techniques and finite element analyses conducted over limited frequency ranges.

The NRC staff had several requests for additional information regarding the use of submodeling, mainly about the assumption of [[

]]. In response, NMPNS determined not to use the submodeling approach. Instead, it decided to use [[

]].

The use of [[

]]. Therefore, the NRC staff has reviewed only a portion of the report that relates to [[
]].

[[

]].

[[

]].

2.2.6.1.7.3 <u>Steam Dryer Stress Ratios – CLTP and EPU</u>

[[ ]], though for only two locations the global analyses results gave minimum alternating stress intensity ratio less than 2.76 at CLTP: (1) the lower-most lifting rod restraint brace with an increased weld size, which is one of the Group 1 locations and (2) the outer hood/hood support/cover plate junction with a stress relief cutout, which is the Group 4(c) location [Attachment 7, Reference 9]. NMPNS used the [[ ]] for three other locations in Group 1-4 to establish additional margins.

For Group 1 locations, lifting rod bracket/side plate welds, the dominant frequency range is 128-145 Hz; the reinforcement of the vertical plate reduces the maximum alternating stress intensity at the middle and upper lifting rod support brackets by a factor of 0.18. The increased weld size from ¼" to ½" reduces the maximum alternating stress intensity at the lower lifting rod support bracket weld by a factor of 0.64. The resulting minimum alternating stress intensity ratio for Group 1 locations is at the lower lifting rod support bracket weld and is equal to 3.56 at CLTP at 10 percent frequency shift. Similarly, for the Group 4(c) location, the outer hood/hood support/cover plate junction with a stress relief cutout, the [[ ]] reduces the maximum alternating stress intensity by a factor of 0.8. The resulting minimum alternating stress intensity ratio at the Group 4(c) location is 2.83 at CLTP occurring with the -10 percent frequency shift. This is the minimum alternating stress intensity ratio at CLTP for the post-reinforced NMP2 steam dryer.

Because the flow-induced acoustic resonances are not anticipated in the NMP2 steam dryer, the alternating stress ratios at EPU operation can be obtained by scaling the CLTP values by the steam flow velocity-squared, $(U_{EPU}/U_{CLTP})^2=(1.17562)^2=1.382$. The minimum alternating stress intensity ratio at EPU for the post-reinforced NMP2 steam dryer is (2.83)/ (1.382) = 2.048, which is above the recommended target level of 2.0, and therefore is acceptable to the NRC staff.

2.2.6.1.8 Limit Curves

The NRC staff requested via e-mail dated July 14, 2011, that the NMP2 limit curves be prepared and submitted based upon the NMP2 stress analysis results with revised bias and uncertainty frequency intervals utilized. In the response to this request, NMPNS provides the MSL pressure power spectral density (PSD) limit curves for NMP2 EPU power ascension in Attachment 5 – CDI Technical Note No. 11-17P, "Limit Curve Analysis with ACM Rev. 4.1 for Power Ascension at NMP2, Revision 1," attached to the letter dated August 5, 2011 [Reference 13]. The limit curves are used for monitoring the signals at strain gauge arrays installed on each of the MSLs. NMPNS uses an approach similar to the one used in previous EPU application for developing the limit curves, and the curves are similar to those developed for Vermont Yankee (much lower than actual MSL PSDs measured in the Quad Cities plants prior to the installation of Acoustic Side Branches (ASBs) to mitigate valve singing tones in those plants).

[[

]]. Two sets of curves are generated – Level 1 based on the ASME Code limit of 13,600 psi, and Level 2 based on 80 percent of the ASME Code limit.

The limit curves are based on the highest alternating stress computed for the NMPNS steam dryer at CLTP, including the consideration for frequency shift and are reported in Attachment 7, "Stress Evaluation of NMP2 Steam Dryer Using ACM Rev. 4.1 Acoustic Loads," Revision 0 [9]. The acoustic pressure loads used to perform the stress analysis were first modified by applying several bias errors and uncertainties before performing the analysis:
(1) frequency-dependent bias errors and uncertainties associated with Rev. 4.1 of the ACM, (2) uncertainties associated with the MSL pressure measurements, (3) bias error and uncertainties introduced by the finite element analysis, which include [[

]].

The highest alternating stress as reported in Attachment 7 [Reference 9] is used to compute a minimum (most conservative) alternating stress ratio of 2.83 at CLTP. The square of this stress ratio [8.01 = $(2.83)^2$] is multiplied by the existing MSL power spectra at CLTP conditions to generate limit curves for each MSL measurement location. The limit curves are provided in Attachment 5 to Reference 13.

The development of the limit curves for use in monitoring during the power ascension phase is based on the minimum allowable alternating stress ratio of 1.0. It should be noted that the recommended minimum alternating stress ratio for the steam dryer at EPU is 2.0 during the steam dryer stress analyses phase. This is acceptable because it is extremely unlikely that the dryer stress ratio will reach close to 1.0 or even decrease below 2.0 without significantly violating the limit curves. There are two reasons for this assessment: (1) MSL strain gauge measurements at all eight strain gauge locations would need to approach the corresponding limit curves over the entire frequency range (0 to 250 Hz) for stress ratios to approach 1.0. This is extremely unlikely because the BUF for the entire frequency range is [[ ]], which is much smaller than the square of the minimum alternating stress ratio [[ ]] as discussed in the preceding paragraph, (2) as discussed before, the minimum alternating stress ratio at EPU is 2.048, which takes into account all the bias errors, uncertainties and BUFs. Therefore, the stress ratio at EPU is not expected to fall below 2.0 unless there is a significant unexpected increase in the strain gauge measurements at certain frequencies, which may be due to acoustic resonance. The main purpose of the limit curves is to monitor for such unanticipated increases in the strain gauge measurements during power ascension.

As a further precaution, if any peak from the MSL strain gauge data at any frequency exceeds the corresponding Level 1 limit curve during power ascension, the licensing conditions discussed in Section 3.4 require that NMPNS return the facility to a lower power level at which the limit curve is not exceeded. NMPNS will resolve the uncertainties in the steam dryer analysis, evaluate the continued structural integrity of the steam dryer ensuring that the minimum alternating stress ratio is greater than 2.0, and provide that evaluation to the NRC staff. In the event that acoustic signals are identified that challenge the limit curves during power ascension, NMPNS will perform a frequency-specific assessment [[

]]. Therefore, even though selected limit curves based on an assumed dryer alternating stress margin of 1.0 may be exceeded, the actual stress margins are not expected to fall below 2.0.

2.2.6.2 <u>Steam, Feedwater, and Condensate Systems and Components</u>

The NRC staff's review of steam, feedwater, and condensate system and components is covered under Section 2.2.2.2 of this SE. As stated in that section, the NRC staff finds that the licensee, using the current design basis and code of record, has adequately addressed the effects of the proposed EPU on the BOP piping, pipe components and pipe supports. Based on its review, as summarized above, the NRC staff concludes that the proposed EPU does not adversely affect the structural integrity of the steam, feedwater, and condensate system and components.

2.2.6.3 <u>Power Ascension Test Plan</u>

Attachment 7 [Reference 1] of May 27, 2009 NMP2 submittal describes the EPU Test Plan. For implementation of EPU at NMP2, the comprehensive startup testing that NMP2 will conduct is included in the plan. EPU power increases will be made in predetermined increments of ≤ 5 percent power starting at 90 percent CLTP. Steam dryer performance will be confirmed to be within limits by determination of steam moisture content during power ascension testing. Vibration monitoring of main steam, feedwater, and other balance of piping will be performed to assess the effect of EPU on piping. Section 6 of Attachment 2 to the NMPNS letter dated December 23, 2009 [Reference 3] provides a discussion regarding power ascension monitoring and data evaluation to confirm that the steam dryer stresses are within acceptable limits during power ascension.

NMPNS provided an overview of the NMP Unit 2 EPU Power Ascension Test Plan or Program (PATP) in Attachment 11 [Reference 1] of May 27, 2009 submittal The purpose of EPU test program is to demonstrate that SSCs will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with the design criteria at EPU conditions. The program describes plans for the initial approach to verify plant performance at EPU, needed transient testing, and the test program's conformance to 10 CFR Part 50, Appendix B, Criterion XI related to the establishment of test program to demonstrate the satisfactory performance of the SSCs in service. The three main elements of the PATP are: (1) a slow and deliberate power ascension with defined hold points and plateaus allowing time for monitoring and analysis; (2) a detailed power ascension monitoring and analysis program to trend steam dryer and piping system performance; and (3) a long term inspection program to verify steam dryer and piping system performance at EPU conditions. Relevant data and evaluations will be transmitted to the NRC staff during the power ascension.

In preparation for EPU power ascension, NMPNS will prepare a Startup Test Plan to include: (a) stress limit curves to be applied for evaluating steam dryer performance; (b) specific hold points and their duration during EPU power ascension; (c) activities to be accomplished during hold points; (d) plant parameters to be monitored; (e) inspections and walkdowns to be conducted for steam, FW, and condensate systems and components during the hold points; (f) methods to be used to trend plant parameters; (g) acceptance criteria for monitoring and trending plant parameters, and conducting the walkdowns and inspections; (h) actions to be taken if acceptance criteria are not satisfied; and (i) verification of the completion of commitments and planned actions specified in its application and all supplements to the application in support of the EPU license amendment request pertaining to the steam dryer prior to power increase above 3467 MWt. NMPNS will submit the flow-induced vibration related portions of the EPU startup test procedure to the NRC, including the methodology for updating the limit curves, prior to initial power ascension above 3467 MWt [Attachment 2, Reference 13].

The NMP2 PATP will provide for power ascension monitoring and analysis to trend steam dryer and critical piping system performance. Under the PATP, power will be increased at a rate of no more than 1 percent CLTP per hour. Steam line strain gauge and accelerometer vibration data will be collected hourly during power ascension. At every 2.5 percent CLTP step, MSL strain gauge and accelerometer data, and moisture carryover data, will be evaluated against acceptance criteria. At every 5 percent CLTP plateau, the data will be evaluated against the acceptance criteria, plant walkdowns will be conducted, and information will be forwarded to the NRC. The stress and moisture carryover criteria will have two threshold action levels, where exceedance of Level 1 criteria requires that power be reduced to a previous acceptable level and exceedance of Level 2 criteria requires that power be held at that level with a re-evaluation of the data [Attachment 2, Reference 13].

Upon completion of the power ascension to EPU, NMPNS will prepare a report on the performance of the steam dryer and plant systems during the EPU power ascension. The report will include evaluations or corrective actions that were required to obtain satisfactory steam dryer performance. The report will also include relevant data collected at each power step, comparisons to performance criteria (design predictions), and evaluations performed in conjunction with steam dryer structural integrity monitoring. NMPNS will forward this report to the NRC.

NMPNS will prepare a specific NMP2 EPU Implementation and Power Ascension Test Plan. Phase I includes preparation of the Test Plan and procedures. Phase II includes instrument setpoint changes, pre-outage activities, and implementation of major modifications. Phase III consists of two major phases: startup to CLTP (3,467 MWt), and power ascension from CLTP to the final Target Uprate Power (TPU) of 3,988 MWt (115 percent CLTP). Phase IV includes periodic monitoring of moisture carryover, on-going system monitoring activities, and steam dryer and other reactor internals inspections. In addition to monitoring routine operating performance parameters, NMPNS will conduct detailed monitoring and analyses to trend the performance of the steam dryer and system piping through MSL strain gauges, piping accelerometers, and moisture carryover evaluations [Attachment 11, Reference. 1].

In response to NRC staff's RAI, NMPNS submitted CDI Technical Note No. 11-17P, "Limit Curve Analysis with ACM Rev. 4.1 for Power Ascension at NMP2, Revision 1," as Attachment 5 to letter dated August 5, 2011 [Reference 13]. The limit curves are for use in monitoring the MSL strain gauge data during the NMP2 power ascension. CDI Technical Note 11-17P discusses the development of Level 1 and Level 2 limit curves for the NMP2 power ascension. The Level 1 limit curves are based on maintaining the ASME allowable alternating stress value for the maximum alternating stress in the steam dryer. The Level 2 limit curves are based on maintaining 80 percent of the allowable alternating stress value for the dryer alternating stress. The NRC staff review of this information reveals that the limit curves do not allow significant resonance peaks in the NMP2 MSLs to occur before reaching the limit curve values.

In Attachment 2 [Reference 13] to letter dated August 5, 2011, NMPNS provided proposed regulatory commitments regarding potential adverse flow effects for power ascension. The NRC proposed license conditions pertaining to steam dryer are included in section 3.4 of this SE and would provide monitoring of plant performance, evaluating plant data, and taking prompt action in response to potential adverse flow effects from EPU operation on plant structures, systems, and components.

As license conditions during EPU power ascension of NMP2, NMPNS will monitor hourly the MSL strain gauge data during power ascension above 3467 MWt for increasing pressure fluctuations in the steam lines. NMPNS will hold the facility for 24 hours at 105 percent and 110 percent of 3467 MWt to collect data from the MSL strain gauges, conduct plant inspections and walkdowns, and evaluate steam dryer performance based on these data. NMPNS will provide the evaluation to the NRC staff upon completion of the evaluation; and will not increase power above each hold point until 96 hours after the NRC confirms receipt of the evaluation.

If any frequency peak from the MSL strain gauge data exceeds a Level 1 limit curve, NMPNS will return the facility to a lower power level at which the limit curve is not exceeded. NMPNS will resolve the uncertainties in the steam dryer analysis; evaluate the continued structural integrity of the steam dryer ensuring that the minimum alternating stress ratio is greater than

2.0; and provide that evaluation to the NRC staff. NMPNS will obtain NRC approval of that evaluation prior to further increases in reactor power. In the event that acoustic signals are identified that challenge the limit curves during power ascension, NMPNS will [[ ]], and perform a frequency-specific assessment [[ ]].

NMPNS will monitor RPV water level instrumentation and MSL piping accelerometers on an hourly basis during power ascension above 3467 MWt. If resonance frequencies are identified as increasing above nominal levels in proportion to strain gauge instrumentation data, NMPNS will stop power ascension, evaluate the continued structural integrity of the steam dryer, and provide that evaluation to the NRC staff.

After reaching 105 percent, 110 percent and 115 percent of 3467 MWt, respectively NMPNS will obtain measurements from the MSL strain gauges and establish the steam dryer flow-induced vibration load fatigue margin for the facility, update the dryer stress report, and re-establish the limit curves with the updated ACM load definition, which will be provided to the NRC staff. If an engineering evaluation is required because a Level 1 acceptance criterion is exceeded, NMPNS will perform the structural analysis to address frequency uncertainties up to ±10 percent and assure that peak responses that fall within this uncertainty band are addressed.

NMPNS will submit a report with the results of the NMP2 PATP following completion of the power ascension. As part of the post EPU monitoring program, NMPNS will monitor plant parameters indicative of degradation of the steam dryer or plant systems during EPU operation. For example, moisture carryover will be monitored with the results reviewed and evaluated. As MSL strain gauges and accelerometers remain operable, data collection may be performed during the remainder of the operating cycle following EPU implementation. Steam dryer inspections and monitoring of plant parameters potentially indicative of steam dryer failure will be conducted as recommended in General Electric Service Information Letter (GE SIL 644), "BWR Steam Dryer Integrity," and Electric Power Research Institute (EPRI) Technical Report 1011463, "BWR Vessel and Internals Project, Steam Dryer Inspection and Flaw Evaluation Guidelines (BWRVIP-139)." The results of the visual inspections of the steam dryer will be reported to the NRC staff within 90 days following startup from the respective refueling outage.

The NRC staff has reviewed the NMP2 PATP for its ability to provide a slow and deliberate power ascension that allows for monitoring of plant data, evaluating steam dryer and system performance, and taking corrective action in the event that plant data reveal such action is appropriate. Further, the NRC staff compared the proposed license conditions for NMP2 with those applied at Hope Creek and the Vermont Yankee power ascension. The NRC staff finds that the NMP2 PATP and the applicable license conditions provide an acceptable power ascension process that is consistent with the successful approach employed at Hope Creek, and Vermont Yankee. The NRC staff has included the license conditions proposed by NMP2 with minor adjustments (Section 3.4 of this SE).

Conclusion

The NRC staff has reviewed the licensee's evaluations of potential adverse flow effects on the MS, FW, and condensate systems and their components (including the steam dryer) for the operation of NMP2 at EPU conditions. The NRC staff concludes that the licensee has provided reasonable assurance that the flow-induced effects on the steam dryer (strengthened by several structural modifications to reduce stresses at EPU conditions) and other plant equipment are within the structural limits at CLTP conditions and extrapolated EPU conditions. The NRC staff further concludes that the licensee has demonstrated that the MS, FW, and condensate systems and their components (including the steam dryer) will continue to meet the requirements of GDCs 1, 2, 40, and 42 following implementation of the proposed EPU at Nine Mile Unit 2, subject to the license conditions in this SE. Therefore, the NRC staff concludes that the proposed license amendment to operate Nine Mile Unit 2 at the proposed EPU conditions is acceptable with respect to potential adverse flow effects.

2.3 Electrical Engineering

2.3.1 Environmental Qualification of Electrical Equipment

Regulatory Evaluation

Environmental qualification (EQ) of electrical equipment demonstrates that the equipment is capable of performing its safety function under significant environmental stresses which could result from design-basis accidents (DBAs). The NRC staff's review focused on the effects of the proposed EPU on the environmental conditions that the electrical equipment will be exposed to during normal operation, anticipated operational occurrences, and accidents. The NRC staff's review was conducted to ensure that the electrical equipment (existing and added to 50.49 program as applicable) will continue to be capable of performing its safety functions following implementation of the proposed EPU. 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

Inside Containment

EQ for safety related electrical equipment located inside containment is based on main steam line break (MSLB), DBA, and loss-of-coolant accident (LOCA) conditions and their resultant temperature, pressure, humidity, and radiation consequences. The EQ also includes the environment expected to exist during normal plant operation. The NRC staff reviewed the licensee's EPU application. Based on its review, the NRC staff verified that the normal operating temperatures will continue to be bounded by the temperatures used in the licensee's EQ analyses. Furthermore, the NRC staff verified that the post-accident peak temperature and pressure will continue to be bounded by the peak temperature and pressure conditions used in the licensee's EQ analyses.

The radiation EQ for safety related electrical equipment inside containment is based on the radiation environment expected to exist during normal operations, post-LOCA conditions, and the resultant cumulative radiation doses. The licensee noted that the radiation levels would increase above the levels used in their current EQ program. The NRC staff reviewed the licensee's EQ evaluation and confirmed that the increase would not affect the qualification of the EQ equipment located inside containment. The staff reviewed the licensee's EQ evaluation which confirmed that the increase in integrated dose will cause some components in containment to reach EQ dose limits prior to the end of plant life. These components will be replaced as required prior to end of qualified life in accordance with the EQ program. The remaining components will still have qualified lives beyond the end of plant life. Based on its review of the licensee's application and supplemental responses, the NRC staff finds that the total integrated radiation doses (normal plus accident) for EPU conditions would not adversely affect the qualification of equipment inside containment.

Outside Containment

The licensee stated that accident temperature, pressure, and humidity environments used for qualification of equipment outside containment result from MSLB or other high-energy line breaks (HELBs), whichever is limiting for each plant area. The licensee evaluated the temperature, pressure, and humidity profiles that were not bounded by current licensed thermal power conditions to ensure that the new profiles do not adversely affect the qualification of safety related electrical equipment.

The staff reviewed the licensee's EQ evaluation and confirmed that the increase in integrated dose will cause some components outside containment to reach EQ dose limits prior to the end of plant life. These components will be replaced as required prior to end of qualified life in accordance with the EQ program. In addition, 17 components will require shielding to be installed to reduce post accident dose to meet EQ program requirements.

The NRC staff also verified that the long-term post-accident temperatures would not adversely affect the qualification of safety related electrical equipment. The licensee stated that the normal temperature, pressure, and humidity conditions do not change significantly as a result of EPU. Based on its review of the licensee's application and supplemental responses, the NRC staff verified that the change of the normal operating temperature, pressure, and humidity conditions will not adversely affect the qualification of safety related electrical equipment.

The licensee noted that the radiation levels would increase above the levels used in their current EQ program and that for components in the area of Standby Gas Treatment filters 1A and 1B, existing qualification would be challenged. These filters will be shielded to reduce the post-accident dose to the components in these zones enough to maintain qualification and extend qualified life. The NRC staff reviewed the licensee's EQ evaluation and supplemental responses and confirmed that with the shielding modification to reduce exposure to components in the area around the Standby Gas Treatment Filters, the increase would not affect the qualification of the EQ equipment located outside of containment. Based on its review of the application and supplemental responses, the NRC staff finds that the total integrated radiation doses (normal plus accident) for EPU conditions would not adversely affect the qualification of the EQ equipment located outside containment.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the EQ of electrical equipment and concludes that with the specified shielding modification outside of the containment, the licensee has adequately addressed the effects of the proposed EPU on the environmental conditions inside and outside containment 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 EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the EQ of electrical equipment.

2.3.2 <u>Offsite Power System</u>

<u>Regulatory Evaluation</u>

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 EPU.

The NRC's acceptance criteria for offsite power systems are based on General Design Criteria (GDC)-17. Based on a review of the NMP2's USAR, the NRC staff identified that the offsite power system is designed in accordance with GDC-17.

The specific review criteria are contained in SRP Sections 8.1 and 8.2, Appendix A to SRP Section 8.2, and Branch Technical Positions (BTPs) PSB-1 and ICSB-11.

<u>Technical Evaluation</u>

The NMP2 offsite power system is designed to provide adequate power to site loads given that the 345 kilo-volt (kV) and 115 kV grid voltages are within the ranges specified by plant procedures.

The NMP2 main generator is connected to the 345 kV switchyard via main generator step-up transformers (GSUs). The 115kV offsite sources originate from 345/115kV transformers, circuit breakers, disconnect switches, reserve station service transformers and transmission lines. The existing off-site electrical equipment was determined to be adequate for operation with the uprated electrical output and increased electrical loading.

The GSU transformer cooling system and the isolated phase bus (IPB) duct will be modified to provide additional transformer and isolated phase bus thermal margin prior to operation at EPU conditions.

The existing protective relay settings for the offsite circuit equipment were determined to be adequate for operation with the EPU electrical output since they were developed and validated based on equipment ratings, which are not being changed for EPU.

Grid studies were performed, considering the increase in electrical output, to demonstrate conformance to GDC 17. The analysis determined that the power uprate will not adversely impact grid stability in accordance with grid reliability standards. The summary grid study demonstrates that the NMP2 electrical output can be increased to 1368.9 mega-watts (MW) electric gross without compromising the offsite power grid or its capability to supply in-plant loads. Since the proposed increase is within the limit identified in the grid load study, the NRC staff finds that the proposed power uprate should not adversely affect the stability of the electric power grid.

Conformance to the NMP2 licensing bases is controlled by required load studies for changes to the site alternating current (AC) electrical system. The AC load study is described in the NMP2 USAR. The AC load studies include minimum and maximum equipment voltages for steady state operation and motor starting. It also includes, by reference, the degraded voltage setpoints.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the offsite power system and concludes that the offsite power system will continue to meet the NMP2 USAR principal design criteria and GDC-17 following implementation of the proposed EPU.

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 EPU on grid stability is negligible. Therefore, the NRC staff finds the proposed EPU 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 anticipated operational occurrences and accident conditions.

The NRC's acceptance criteria for offsite power systems are based on GDC-17. Based on a review of the NMP2's USAR, the NRC staff identified that the onsite power system is designed in accordance with GDC-17.

Specific review criteria are contained in SRP Sections 8.1 and 8.3.1.

Technical Evaluation

The NRC staff reviewed the licensee's submittal to determine whether the emergency diesel generators (EDGs) would remain capable of performing their intended function at EPU conditions. The NMP2 EDGs provide power to essential AC loads including adequate distribution, protections, and control for design basis events with a simultaneous loss of offsite power (LOOP). The essential AC system provides power distribution and control of loads during these events.

There are no changes to the ratings of safety related loads and no new safety related loads normally powered from the EDG as a result of EPU. The EPU also does not involve any changes to load shedding circuits or essential bus transfers. The EDG load analysis is based on the nameplate equipment rating or brake horsepower of the loads in both normal and emergency operating scenarios.

The EDG continuous load rating of 4400 kW envelopes the initial and steady-state loading. In addition, EDG transient voltage and frequency performance is not affected. Based on this information, the NRC staff finds that the EDG design basis loading should not be affected by EPU.

The most significant changes in plant electrical load were related to main power generation system loads such as Feedwater, Condensate, and Heater Drain pumps and a small change (<1 percent) for the Reactor Recirculation pump load. The new loading was evaluated in both normal and emergency conditions with equipment operating at or below the nameplate ratings. Load flow, voltage drop and short circuit current calculations were performed to verify the adequacy of the on-site AC system for the proposed changes. In addition, protective relay settings were evaluated as adequate for loading, coordination and protection.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the AC onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's functional design. The NRC staff further concludes that the AC onsite power system will continue to meet the NMP2 USAR principal design criteria and GDC-17 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU 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 is based on GDC-17, insofar as it requires the system to have the capacity and capability to perform its intended functions during anticipated operational occurrences and accident conditions.

The NRC's acceptance criteria for onsite power systems (which include DC power systems) are based on GDC-17. Based on a review of the NMP2's USAR, the staff identified that the DC power system is designed in accordance with GDC-17.

Specific review criteria are contained in SRP Sections 8.1 and 8.3.2.

Technical Evaluation

The NRC staff reviewed the licensee's submittal (including necessary modifications) and the USAR to determine whether the DC system and its components would remain capable of performing their intended design function at EPU conditions. The licensee stated that at EPU conditions the integrated safety related and station blackout (SBO) DC loads remain bounded by the existing battery capacity.

Conclusion

The NRC staff has reviewed the USAR and the licensee's assessment of the effects of the proposed EPU on the DC onsite power system and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system's functional design. The NRC staff further concludes that the DC onsite power system will continue to meet the NMP2 USAR principal design criteria and GDC-17 following implementation of the proposed EPU. 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 EPU acceptable with respect to the DC onsite power system.

2.3.5 Station Blackout

Regulatory Evaluation

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 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 EPU 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

The licensee re-evaluated SBO using the guidelines of NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors." The licensee stated that NMP2's response to and coping capabilities for an SBO event would be affected slightly by operation at EPU due to the increase in the initial power level and decay heat. However, the licensee indicated that no changes are necessary to the systems and equipment used to respond to an SBO and that the SBO coping duration does not change under EPU conditions.

The licensee stated that areas containing equipment necessary to cope with an SBO event were evaluated for the effect of loss-of-ventilation due to an SBO. The licensee's evaluation showed that equipment operability is bounded due to conservatism in the existing design and qualification bases. The battery capacity remains adequate to support the plant's high pressure injection function (via RCIC operation) at EPU conditions. In addition, adequate compressed gas capability exists to support main steam SRV relief valve actuations.

Having adequate condensate inventory ensures that adequate water volume is available to remove decay heat and maintain reactor vessel level above the top of active fuel. The licensee calculated the required condensate inventory for decay heat removal (105,000 gallons) using the method described in NUMARC 87-00. The NRC staff confirmed that this quantity is within the available condensate storage tank inventory (135,000 gallons).

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU 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 EPU on SBO and demonstrated that the plant will continue to meet the requirements of 10 CFR 50.63 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to SBO.

2.4 Instrumentation and Controls

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 engineered safety features (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, engineered safety feature actuation system (ESFAS), safe shutdown systems, control systems, and diverse instrumentation and control systems for the proposed EPU to ensure that the systems and any changes necessary for the proposed EPU 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 related to the quality of design of protection and control systems are based on 10 CFR 50.55a(a)(1), 10 CFR 50.55a(h), and GDCs 1, 4, 13, 19, 20, 21, 22, 23, and 24. Specific review criteria are contained in SRP Sections 7.0, 7.2, 7.3, 7.4, 7.7, and 7.8.

Technical Evaluation

2.4.1 Suitability of Existing Instruments

For the proposed power uprate, the licensee evaluated each existing instrument of the affected nuclear steam supply systems (NSSS) and balance-of-plant (BOP) systems to determine its suitability for the revised operating range of the affected process parameters. Where operation at the power uprate condition impacted safety analysis limits, the licensee verified that the acceptable safety margin continued to exist under all conditions of the power uprate. Where necessary, the licensee revised the setpoint and uncertainty calculations for the affected instruments. Apart from a few devices that needed change, the licensee's evaluations found most of the existing instrumentation acceptable for proposed power uprate operation. The licensee's evaluation resulted in the following changes:

Parameter	Change
MSL High Flow	Revise setpoints[15]
1st Stage Turbine Pressure	Respan transmitters, indicators and associated loop instruments Revise setpoints
APRM flow biased STP scram	Revise APRM setpoints
APRM flow biased STP rod block	Revise APRM setpoints
RWM LPSP	Revise setpoints
Crossaround Steam Pressure	Respan transmitters, indicators and associated loop instruments Adjust EHC power to load comparator
High Pressure Turbine (HPT) Exhaust Pressure	Respan transmitters, indicators and associated loop instruments
MS Drain Receiver Outlet Temperature	Respan indicators and associated loop instruments
Inlet Press to Low Pressure Turbine (LPT)	Respan transmitters, recalibrate instrument loop
MSR Outlet Pressures	Respan associated loop instruments and revise alarm setpoints[16]
Main Steam Temperature	Respan indicators and associated loop instruments
Condensate Polisher Flow Low Alarm	No change required[17]
Condensate Polisher and Strainer delta P	No change required[18]

[15] Table 2.4-2 of the PUSAR originally indicated that for the MSL High Flow parameter, respan of the transmitters and associated loop components and revised setpoints were required to support operation at EPU conditions. As indicated in Reference 55, the licensee subsequently determined that respan of the transmitters and associated loop components is not necessary.

[16] Table 2.4-2 of the PUSAR originally indicated that for the MSR Outlet Pressure parameter, replacement of transmitters, respan of the associated loop instruments, and revised alarm setpoints were required to support operation at EPU conditions. As indicated in Reference 55, the licensee subsequently determined that transmitter replacement is not necessary.

[17] Table 2.4-2 of the PUSAR originally indicated that for the Condensate Polisher Low Flow Alarm parameter, revised setpoints were required to support operation at EPU conditions. As indicated in Reference 55, the licensee subsequently determined that a setpoint revision is not required.

[18] Table 2.4-2 of the PUSAR originally indicated that for the Condensate Polisher and Strainer delta P parameter, revised setpoints were required to support operation at EPU conditions. As indicated in Reference 55, the licensee subsequently determined that a setpoint revision is not required.

Condensate, Condensate Booster Pump and FW Pump Pressures, Temperatures, & Flows	Respan indicators and associated loop instruments Revise alarm setpoint
SRV Discharge Temperature	Respan indicators Revise alarm setpoint
Turbine Steam Bypass Outlet Temperature	Respan indicators Revise alarm setpoint
Turbine Condenser Vacuum (Alarm Low)	Revise low vacuum alarm setpoint
MSR Outlet Temperatures	Respan indicators Revise alarm setpoint
Main Steam Inlet Header Pressure	No changes required[19]
MSL Flow	Replace transmitters and respan associated loop components Revise alarm setpoint
FWH Temperatures	Respan indicators and computer points Revise alarm setpoints
RMS/CMS/MSS/Various Radiation Monitors	Setpoints are based on background radiation input which will be revised as required during EPU power ascension
Feedwater Pump Motors	Replace ammeters and revise protective relay settings
Feedwater Flow to Reactor	Respan transmitters, indicators and associated loop instruments
Final Feedwater Pressure to Reactor	Respan transmitters, indicators and associated loop instruments
Feedwater Flow Differential Pressure	Respan transmitters, indicators and associated loop instruments
Feedwater to Reactor Temperatures	Respan indicators and revise alarm setpoints
RFP Recirculation Temperatures	Respan indicators and revise alarm setpoints
Reheater Drain Temperatures	Respan indicators and revise alarm setpoints
FWH Extraction Steam Pressures	Respan indicators and revise alarm setpoints
FWH 4 HDP 1A/B/C Suction Pressure	Revise setpoints

[19] Table 2.4-2 of the PUSAR originally indicated that for the Main Steam Inlet Header Pressure parameter, replacement of transmitters, respan of the associated loop instruments, and a revised alarm setpoints were required to support operation at EPU conditions. As indicated in Reference 55, the licensee subsequently determined that these changes are not necessary.

HDP Recirculation Control	Respan instrument loop
Scavenging Steam Line Pressure and Temperatures	Respan transmitters, indicators and associated loop instruments Revise alarm setpoint
Reheater Shell Pressures	Respan instrument loop Revise computer points
Off Gas Recombiner Outlet Temperature	Revise high alarm and trip setpoints
Main Turbine Load and Load Set Meters	Respan indicator scales

These changes will be made to accommodate the revised process parameters. Section 2.4.2 of this SE discusses instrumentation changes covered by TSs. These changes are based on the system review and analysis, which the NRC staff reviewed and documented in Sections 2.5 and 2.8 of this SE. In addition, the licensee will confirm the acceptability of these changes during power ascension testing. Therefore, the NRC staff agrees with the licensee's conclusion that when the above modifications and changes are implemented, NMP2 instrumentation and control systems will accommodate the proposed power uprate without compromising safety.

2.4.2 Instrument Setpoint Methodology

APRM Flow-Biased Simulated Thermal Power - Upscale Scram

The setpoints for this function were changed for the implementation of the ARTS/MELLLA amendment in accordance with NRC approved GEH methodology in NEDC-31336P-A,"General Electric Instrument Setpoint Methodology." The instrument uncertainties related to this EPU were sufficiently small to apply a simplified process to change the instrument Allowable Value and nominal trip setpoint. Following NRC approved GEH methodology in NEDC-33004P-A, "Constant Pressure Power Uprate", the licensee changed the Allowable Value and nominal trip setpoint by the same difference as the change in the Analytical Limit. The nominal trip setpoint (NTSP) is 0.55 W + 57.5 percent RTP for two loop operation and 0.50 (W-5 percent) + 50.5 percent RTP for single loop operation, where W = Recirculation Drive Flow in percent of Rated Flow. The Analytical Limit for this function is 0.55 W + 63.5 percent RTP for two loop operation and 0.50 (W-5 percent) + 56.5 percent RTP for single loop operation.

Main Steam Line High Steam Flow Main Steam Isolation Valve (MSIV) Isolation

The Analytical Limit for EPU conditions was maintained at 140 percent of the rated steam flow and the Allowable Value and NTSP both increase in units of psid due to the higher absolute mass flowrate. The Allowable Value and NTSP were re-calculated using NRC approved GEH methodology in NEDC-31336P-A, "General Electric Instrument Setpoint Methodology" and NEDC-32889P, "General Electric Methodology for Instrumentation TS and Setpoint Analysis." A sample calculation demonstrating the application of this methodology was provided by the licensee in Section 2.4.2 of the power uprate safety analysis report. The NTSP is 183 psid. The Analytical Limit for this function corresponding to 140 percent rated steam flow is 194.4 psid. The methodology is acceptable based on the application of the previously approved methodology.

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

APRM Flow-Biased Simulated Thermal Power - Upscale Scram

The NRC staff previously concluded in Amendment No. 123 dated February 27, 2008 (ML080230230), SE section 3.13.2 that the APRM Flow-Biased Simulated Thermal Power - Upscale Scram is not a SL-Related LSSS. Regarding the current amendment, the TS Bases for Specification 3.3.1.1 states no specific safety analyses take direct credit for the APRM Flow Biased Simulated Thermal Power - Upscale Function. This function does not provide an automatic trip setpoint that protects against violating the Reactor Core Safety Limit or Reactor Coolant System Pressure Safety Limit during an anticipated operational occurrence. Based on the clarifications provided by the licensee and the NRC staff's review documented in Section 2.8, APRM Flow-Biased Simulated Thermal Power - Upscale Scram is not a SL-Related LSSS.

Main Steam Line High Steam Flow MSIV Isolation

The Main Steam Line Flow-High Function is directly assumed in the analysis of the main steam line break accident. The MSL Flow-High Function is credited only in a design-basis accident and does not provide an automatic trip setpoint that protects against violating the Reactor Core Safety Limit or Reactor Coolant System Pressure Safety Limit during AOOs. Based on the clarifications provided by the licensee and the NRC staff's review documented in Section 2.8, Main Steam Line High Steam Flow MSIV Isolation is not a SL-Related LSSS.

Instrument Setpoint Controls

The NRC staff agrees that changes to Main Steam Line High Steam Flow MSIV Isolation and APRM Flow-Biased Simulated Thermal Power - Upscale Scram meet with requirements of 10 CFR 50.36 as provided in RIS 2006-17 (ML0518100771) and further clarified by TSTF-493, Revision 4, and TSTF letter to NRC dated February 23, 2009 (ML090540849), for non-SL-Related LSSS functions.

Based on the above, the NRC staff concludes that there is reasonable assurance that the plant will operate in accordance with the safety analysis and that the operability of the instrumentation is assured. Therefore, the NRC staff finds the proposed changes meet the requirements of 10 CFR 50.36 and the guidance in RG 1.105, "Setpoints for Safety-Related Instrumentation."

2.4.3 Operating License and Technical Specifications Changes

The following RPS Instrumentation Actions and Surveillance Requirements contained in TS Section 3.3.1.1, including Table 3.3.1.1-1, are dependent on a percentage of RTP and will be revised as shown:

1. Required Action E.1, which requires that Thermal Power be reduced to < 30 percent RTP, will be revised to require that Thermal Power be reduced to < 26 percent RTP.

2. The threshold for performing SR 3.3.1.1.3 (and associated Note) will be revised from ≥ 25 percent RTP to ≥ 23 percent RTP.

3. The threshold for performing SR 3.3.1.1.15, Turbine Stop Valve-Closure and Turbine

Control Valve Fast Closure, Trip Oil Pressure-Low Functions, will be revised from ≥ 30 percent RTP to ≥ 26 percent RTP.

4. The threshold for performing SR 3.3.1.1.16, Average Power Range Monitor (APRM) Oscillation Power Range Monitor (OPRM)-Upscale Function, will be revised from ≥ 30 percent RTP to ≥ 26 percent RTP.

5. Table 3.3.1.1-1, Function 8, Turbine Stop Valve-Closure and Function 9, Turbine Control Valve Fast Closure, Trip Oil Pressure-Low, both specify an applicable mode or other specified conditions of ≥ 30 percent RTP. The ≥ 30 percent RTP value will be revised to ≥ 26 percent RTP.

6. TS Section 3.3.2.2, Feedwater System and Main Turbine High Water Level Trip Instrumentation Applicability and Required Action C.2 are dependent on a percentage of RTP (i.e., 25 percent RTP). The stated RTP percentage will be changed from 25 percent RTP to 23 percent RTP.

The NRC staff notes that the licensee's PUSAR indicates that because the high pressure turbine was replaced, a new setpoint was calculated. The turbine steam path is also being modified for the uprated steam flow. The NRC staff has reviewed the changes and find they follow previously approved GE Nuclear Energy Licensing TR NEDC-33004P-A, Licensing TR Constant Pressure Power Uprate, Revision 4, [[ ]].

Items 2 and 6 above are associated with reactor core safety limit and related settings and are not changed by a ratio of current licensed thermal power to proposed EPU. They are changed according to an alternate method used when power exceeds 4.8 MWt/bundle. The proposed value of 23 percent is acceptable to the NRC staff.

The following RPS Instrumentation Actions and Surveillance Requirements contained in TS Section 3.3.1.1, including Table 3.3.1.1-1, have new setpoints and are revised as follows:

Table 3.3.1.1-1, Function 2.b, Flow Biased Simulated Thermal Power-Upscale, contains both a flow-biased Allowable Value (AV) (≤ 0.64W + 63.8 percent RTP) and a fixed AV clamped at 115.5 percent RTP. The flow-biased AV will be changed to (≤ 0.55W + 60.5 percent RTP). Note (b) modifies the Function 2.b AV when reset for single loop operation per Limiting Condition for Operation (LCO) 3.4.1, Recirculation Loops Operating. Note (b) will be revised to a value of 0.50(W - 5 percent) + 53.5 percent RTP, where W = Recirculation Drive Flow in percent of Rated Flow.

Table 3.3.6.1-1, Primary Containment Isolation Instrumentation, Function l.c, Main Steam Line (MSL) Flow - High, specifies an AV of ≤ 122.8 psid. The stated AV of ≤ 122.8 psid will be changed to ≤ 184.4 psid.

Based on RAI response E1 and E2 in Attachment 12 of Reference 3 which provided clarification of the methodology, the Flow Biased Simulated Thermal Power-Upscale allowable value calculation is acceptable to the NRC staff.

Conclusion

The NRC staff has reviewed the licensee's application related to the effects of the proposed EPU on the functional design of the reactor trip system, ESFAS, safe shutdown system, and control systems. The NRC staff concludes that the licensee has adequately addressed the effects of the proposed EPU on these systems and that the changes that are necessary to achieve the proposed EPU are consistent with the plant's design basis. The NRC staff further concludes that the systems will continue to meet the requirements of 10 CFR 50.55a(a)(1), 10 CFR 50.55(a)(h), and GDCs 1, 4, 13, 19, 20, 21, 22, 23, and 24. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to instrumentation and controls.

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 reviews flood protection measures to ensure that structures, systems, and components (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.

Technical Evaluation

The licensee's evaluation of NMP2 flood protection and moderate line breaks under EPU conditions was based on Section 10.2 of the General Electric (GE) TR, "Constant Pressure Power Uprate, Revision 4," which will be referred to as CLTR. The licensee's evaluation concluded that [[ ]]. The licensee also concluded that the current flood protection analysis for moderate line breaks would remain unchanged for EPU conditions. Since the licensee's analysis of flood protection shows that GDC-2 will continue to be met for EPU conditions, the NRC staff finds the licensee's review acceptable and does not require further evaluation.

Conclusion

The NRC staff has reviewed the flood protection analysis for NMP2 and found that no changes are being made to the fluid volumes in tanks and vessels for the proposed EPU. 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 EPU. Therefore, the NRC staff finds the proposed EPU 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 leak-offs, and tank drains are directed to the proper area for processing or disposal while preventing a backflow of water that might result from maximum flood levels to areas of the plant containing equipment that is important to safety. The EFDS also protects 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 outside containment. The NRC staff's review focused on any changes in fluid volumes or pump capacities that are necessary for the proposed EPU and are not consistent with previous assumptions with respect to floor drainage considerations. The NRC's acceptance criteria for the EFDS are based on GDC-2 and GDC-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).

Technical Evaluation

The licensee evaluation of NMP2 plant equipment and floor drains was based on Section 8.1 of the CLTR. The licensee's evaluation concluded that the EFDS operation and equipment performance will not be affected by the EPU and that there will be no significant increase in total liquid or solid volume at EPU conditions. The licensee also found that the EFDS will maintain the capability to handle expected liquid increases resulting from EPU operation and infiltration of radioactive water into non-radioactive water drains will not occur during EPU operation. The licensee further found that the current design of the drainage systems will maintain both backflow at maximum flood levels and its capability to withstand the effects of earthquakes and environmental conditions at EPU conditions. The NRC staff finds the licensee's assessment acceptable due to EDFS continuing to meet GDC-2 and GDC-4 during EPU conditions and does not require any further evaluation of the EDFS.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU 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 will be no significant increase in total liquid or solid volume at EPU conditions and the EFDS has sufficient capacity to (1) handle the additional expected leakage resulting from the plant changes; (2) prevent the backflow of water to areas with safety related equipment; and (3) ensure that contaminated fluids are not transferred to non-contaminated drainage systems. Based on the above items, the NRC staff concludes that the EFDS will continue to meet the requirements of GDC-2 and GDC-4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU 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 to remove the heat rejected by the turbine cycle and auxiliary systems. The NRC staff's review of the CWS focused on changes in existing flooding analyses that are necessary due to increases in fluid volumes or installation of larger capacity pumps or piping needed to accommodate the proposed EPU. 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.

Technical Evaluation

The licensee indicated that the CWS did not have any physical or design modifications needed for EPU operation. The licensee evaluated the CWS for EPU performance by comparing the design capability to the actual range of circulating water inlet temperatures and found that the CWS will be able to continue its current operation during EPU conditions. The licensee also stated that the CWS will continue to have the capacity during EPU conditions to maintain adequate condenser backpressure while meeting existing environmental permit conditions related to the ultimate heat sink (UHS) and the plant cooling tower.

The NRC staff evaluated the licensee's assessment of the CWS according to GDC-4 and found that the CWS would have the capability to perform its existing functions during EPU conditions. The NRC staff did not find any changes being made to the CWS components and the existing analyses regarding the CWS during normal operations and flooding scenarios would not be impacted by EPU conditions. The NRC staff finds the licensee's assessment acceptable and does not require any further evaluation of the CWS.

Conclusion

The NRC staff has reviewed the licensee's assessment of the CWS and concludes that the CWS would be able to perform its existing functions during EPU conditions. The NRC staff concludes that, consistent with the requirements of GDC-4, the CWS will continue to meet its current design capabilities related to flooding and normal operations for the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CWS.

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, anticipated operational occurrences, or changes in existing system configurations such that missile barrier considerations could be affected. The NRC's acceptance criteria for the protection of SSCs important to safety against the effects of internally generated missiles that may result from equipment failures are based on GDC-4.

Technical Evaluation

The licensee used Section 7.1 of the CLTR to evaluate the effect of the proposed EPU on the turbine generator, as related to the internal turbine missiles. As stated in the LAR, the high-pressure and low-pressure turbine rotors at NMP2 currently have integral, non-shrunk on wheels, which will be unchanged for EPU conditions. [[

]]. The licensee concluded that the proposed EPU will not result in any condition (system pressure increase or equipment overspeed) that could result in an increase in the generation of internally generated missiles at NMP2. In addition, the LAR does not include any additional equipment modifications that could change the effect of internally generated missiles on SSCs or non-safety related equipment.

The NRC staff reviewed the licensee's assessment and references for internally generated missiles and concluded that NMP2 will continue to meet GDC-4, in which the effects of internally generated missiles will not impact the SSCs important to safety after EPU implementation. The NRC staff did not find any alterations to the licensee's current analysis for internal missiles generation that would be affected for EPU conditions. The NRC staff finds the licensee's evaluation of internally generated missiles acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of internally generated missiles and concludes that the NMP2 will continue to meet GDC-4, in which SSCs important to safety will continue to be protected from internally generated missiles following implementation of the proposed EPU. The NRC staff has noted that the licensee's evaluation of system pressures and equipment speed changes due to EPU will remain within the current licensing basis for internally generated missiles. Therefore, the NRC staff finds the proposed EPU acceptable with respect to internally generated missiles.

2.5.1.2.2 Turbine Generator

Regulatory Evaluation

The large steam turbines of the main turbine generator (TG) sets have the potential for producing large high-energy missiles, especially if the turbines should exceed their rated speed. The NRC staff's review of the TG sets focuses on the effects of the proposed EPU on the turbine overspeed protection features to confirm that adequate turbine overspeed protection will continue to be maintained. 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.

Technical Evaluation

The licensee used Section 7.1 of the CLTR to evaluate the effect of the proposed EPU on the turbine generator for NMP2. The licensee stated that the turbine and generator were originally designed with a flow margin of 4.8 percent, which is the difference in the steam-passing capability between the design condition of the turbine and the rated condition. The current rated throttle steam flow is 13.58 Mlbm/hr at a throttle pressure of 1003 psia. For EPU conditions, the rated throttle steam flow will increase to 16.12 Mlbm/hr and at a throttle pressure of 991 psia. The licensee will use a flow margin of 5 percent to design the new high pressure turbine section. The licensee stated that this new flow margin will ensure that the turbine will be able to pass the rated throttle and allow for sufficient margin for reactor pressure control. The high pressure turbine has been redesigned with new diaphragms and buckets to increase the flow passing capacity at EPU operations. The current NMP2 low pressure rotors are monoblock and the replacement high pressure rotor will be monoblock as well. The licensee also stated that the generator will support the steam turbine uprate to 120 percent OLTP for EPU operation.

The licensee discussed the effect of the overspeed calculation for EPU conditions in the LAR and determined that the entrapped steam energy will be increased. The hardware modification design to the turbine and its implementation process establishes the overspeed trip settings to provide turbine trip protection. The licensee concluded that the modification to the turbine for EPU operation will not result in increases in system pressures, configurations, or equipment overspeed that would impact the current analyses of internally generated missiles on safety related or non-safety related equipment.

The NRC staff reviewed the licensee's evaluation of the TG according to GDC-4 and also its impact on the current overspeed protection for the turbine. The NRC staff provided an RAI regarding more clarification of how the increased entrapped energy in the modified turbine will impact the licensee's ability to maintain turbine speed in an acceptable range as well as the overspeed trip settings during EPU conditions. The licensee responded in the February 19, 2010, letter that the high pressure turbine rotor modification will increase the rotor inertia, which will slow the acceleration rate of the turbine should a load rejection event occur. However, the increased entrapped steam energy contained within the turbine and its piping after the valves close will counteractively increase the acceleration rate of the turbine. The licensee will use the overspeed calculation to compare the entrapped steam energy contained within the turbine and the associated piping, after the stop valves trip, and the sensitivity of the rotor train for the capability of overspeeding. This method allows for the licensee to establish the overspeed trip setting for NMP2 for EPU conditions, such that the resulting peak speed will not exceed the 120 percent emergency overspeed limit due to overshoot for any condition. The licensee concludes that the calculation and limit will ensure that the turbine is protected in an overspeed event.

In addition, the licensee also stated that the revised overspeed calculation shows that the mechanical overspeed trip setting will require an adjustment to maintain the turbine overspeed within the 120 percent limit. For EPU conditions, the overspeed trip setting is reduced from the original value of 1966-1984 RPM (109.2-110.2 percent) to 1960-1978 RPM (108.9-109.9 percent). The revised overspeed trip setting will result in an emergency overspeed peak speed limit of less than or equal to 120.0 percent, which would meet the current GE emergency overspeed peak speed limit requirement. The licensee indicated that in addition to this overspeed trip setting, a backup electronic overspeed protection system is available to send a trip signal to the master trip solenoid valve on a detected overspeed condition from independent speed sensors. The licensee reduced the backup electronic overspeed setpoint from 111 percent to 110.5 percent to maintain the design relationship between the mechanical and backup overspeed trip settings.

With the additional information provided by the licensee in the RAI response and assessing the changes to the TG as described in the LAR, the NRC staff finds the TG will continue to meet GDC-4 in regards to maintaining its ability to minimize the probability of generating internal missiles that could impact SSCs important to safety by having adequate overspeed protection in place for EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the TG 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 EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the TG.

2.5.1.3 Pipe Failures

Regulatory Evaluation

The NRC staff conducted a review of the plant design for protection from piping failures outside containment 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, control room 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.

Technical Evaluation

The licensee evaluated the impact of the proposed EPU in four areas regarding pipe failures: (1) high energy piping outside containment; (2) moderate energy piping outside containment; (3) environment conditions; and (4) radiological consequences.

In the analysis of high energy piping outside containment, the licensee assessed that the EPU conditions would not cause any new high energy line break (HELB) locations using the existing NMP2 line break criteria. The licensee also found that the post-HELB control room habitability and areas important to safe control of post-accident operations would not be adversely affected by EPU post-HELB mass release and temperatures and pressures. The licensee also found during its assessment of the minimal effects of the feedwater (FW) line breaks in the main steam tunnel during EPU conditions would continue to be bounded by a main steam line break in the main steam tunnel.

The licensee's additional analyses for moderate energy piping outside containment, environmental conditions, and radiological consequences were shown to continue to meet current design criteria during EPU conditions. In the case for environmental conditions, the HELB pressures and temperatures continue to be bounded by current licensing conditions.

The NRC staff reviewed the licensee's assessment of pipe failures according to GDC-4 and found that the EPU would not affect the protection of SSCs important to safety due to postulated pipe failures. Therefore, the NRC staff finds the area of pipe failures acceptable for EPU conditions and a further evaluation is not required.

Conclusion

The NRC staff has reviewed the licensee's assessment of pipe failures under EPU conditions 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 outside containment and will continue to meet the requirements of GDC-4 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to protection against postulated piping failures in fluid systems outside containment.

2.5.1.4 Fire Protection

Regulatory Evaluation

The purpose of the fire protection program (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; and (2) GDC-3, insofar as it requires that SSCs important to safety be designed and located to minimize the probability and effect of fires, non-combustible and heat resistant materials be used, and 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 of Appendix A to 10 CFR Part 50, 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 Appendix D of NUREG-0800, Revision 5, "Standard Review Plan," Section 9.5.1, as supplemented by the guidance provided in Attachment 2 to Matrix 5 of Section 2.1 of RS-001, Revision 0, "Review Standard for Extended Power Uprates."

The NMP2 fire protection program describes the fire protection features of the plant necessary to comply with Branch Technical Position (BTP) Chemical and Mechanical Engineering Branch (CMEB) 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants." SE report NUREG-1047, dated February, 1985 (Supplements 1 through 6), describe the approved fire protection program for NMP2. These SE reports are listed in the NMP2 Operating License Condition 2.F. In addition to the evaluations described in the NUREG-1047 and Supplements, the NMP2 fire protection program was evaluated for plant license renewal. The evaluation is documented in NUREG-1900, "SE Report Related to the License Renewal of Nine Mile Nuclear Station, Units 1 and 2, dated September 2006.

Technical Evaluation

In Nuclear Reactor Regulation (NRR) RS-001, Revision 0, Attachment 1 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 ... [W]here licensees rely on less than full capability systems for fire events ..., the licensee should provide specific analyses for fire events that demonstrate that: (1) fuel integrity is maintained by demonstrating that the fuel design limits are not exceeded; and (2) there are no adverse consequences on the RPV integrity or the attached piping. Plants that rely on alternative/dedicated or backup shutdown capability for post-fire safe shutdown should analyze the impact of the power uprate on the alternative/dedicated or backup shutdown capability ... The licensee should identify the impact of the power uprate on the plant's post-fire safe-shutdown procedures."

NMPNS developed the LAR utilizing the guidelines in RS-001. In the LAR, the licensee evaluated the applicable SSCs and safety analyses at the proposed EPU core power level of 3988 MWt. The NRC staff's review of the May 27, 2009, LAR, Section 2.5.1.4, of the NEDC-33351P, Revision 0, Attachment 11, identified areas in which additional information was necessary to complete the review of the proposed EPU LAR. By letters dated December 23, 2009, and February 19, 2010, NMPNS responded to the NRC staff RAI as discussed below.

In RAI # D1, the NRC staff noted that Attachment 11 to NEDC-3335 IP, Revision 0, Section 2.5.1.4, "Fire Protection," states that "...Any changes in physical plant configuration or combustible loading as a result of modifications to implement the EPU will be evaluated in accordance with plant modification and fire protection programs...." The NRC staff requested the licensee to clarify whether this request involves plant modifications or physical changes to the fire protection program. If any, the NRC staff requested the licensee to identify proposed modifications and discuss impact of these modifications on the plant's compliance with the fire protection program licensing basis, 10 CFR 50.48, or applicable portions of 10 CFR Part 50, Appendix R.

In its response, the licensee stated that none of the plant modifications listed in Attachment 6, Modifications to Support EPU, represents physical changes to plant fire protection equipment or systems to support EPU conditions. However, this request does involve a modification to the fire protection program. The plant fire protection program licensing basis will be modified as described in Section 2.5.1.4 to change the acceptance criteria for reactor vessel fuel cladding integrity in response to a postulated 10 CFR Part 50 Appendix R fire event at EPU conditions. Currently, Updated Safety Analysis Report (USAR) vessel water level performance criteria for Appendix R safe shutdown requires water level to remain above top of active fuel (TAF). The criteria will be changed from vessel water level remaining above TAF to assuring that peak clad temperature (PCT) remains below 1500 °F in accordance with GE Boiling Water Reactor Owner's Group (BWROG) report, "BWROG Position on the Use of Safety Relief Valves and Low Pressure Systems as Redundant Safe Shutdown Paths," which has been accepted by the NRC in a letter to the BWROG dated December 12, 2000 (ADAMS Accession No. ML003776828).

In the event of a Control Room evacuation the Special Operating Procedure requires the disconnection of Reactor Core Isolation Cooling (RCIC) auto isolation and initiation signals from the Control Room prior to going to the Remote Shutdown Panel (RSP). At the RSP, RCIC is initiated and operated maintaining reactor water level above TAF. If RCIC fails to operate as expected then the low pressure "pseudo" Low-Pressure Coolant Injection (LPCI) mode of the Residual Heat Removal (RHR) system and the four Safety Relief Valves (SRVs) are operated at the RSP to depressurize and inject water into the vessel. The 1500 °F peak cladding temperature criteria in lieu of water level remaining above TAF will apply when using the low pressure "pseudo" LPCI mode of the RHR system and the four SRVs.

The licensee's response satisfactorily addresses the NRC staff's concerns, and this RAI issue is considered resolved as follows:

The licensee indicated that for the proposed EPU condition there is no physical changes to plant fire protection equipment or systems. However, the proposed EPU would revise the fire protection program as discussed in LAR, Section 2.5.1.4, of the NEDC-33351P, Revision 0, Attachment 11, regarding acceptance criteria for reactor vessel fuel cladding integrity in response to a postulated 10 CFR Part 50 Appendix R fire event at EPU conditions. The criteria will be changed from reactor vessel water level remaining above TAF to assuring that PCT remains below 1500 °F. The 1500 °F peak cladding temperature criterion in lieu of water level remaining above TAF will apply when using the low pressure "pseudo" LPCI mode of the RHR system and the four SRVs in accordance with GE BWROG report, "BWROG Position on the Use of Safety Relief Valves and Low Pressure Systems as Redundant Safe Shutdown Paths." The NRC staff approved the GE BWROG report by a SE Report on the use of SRVs and low pressure (LPS) as a "redundant" post-fire safe-shutdown system under 10 CFR Part 50, Appendix R in a letter to BWROG dated December 12, 2000 (ADAMS Accession No. ML003776828).

By letter dated September 23, 2011, the licensee stated that subsequent installation scoping activities for two EPU modifications identified the need for ancillary changes to fire protection systems. These changes are: (1) extending an existing sprinkler system to cover a new cable tray associated with the feedwater pump motor cable replacement modification; and (2) a minor relocation of existing sprinkler system piping to accommodate interferences associated with installation of the main transformer cooling upgrade modification. The NRC staff finds that these changes will not affect the plant's safe shutdown analysis to ensure that SSCs required for the safe shutdown are protected from the effects of a fire and will continue to be able to achieve and maintain safe shutdown following a fire.

In RAI # D2, the NRC staff noted that Attachment 11 to NEDC-3335 IP Revision 0, Section 2.5.1.4, "Fire Protection," states that "...the safe shutdown systems and equipment used to achieve and maintain cold shutdown conditions do not change, and are adequate for EPU conditions. The operator actions required to maintain the consequences of a fire are defined...." The NRC staff requested the licensee to verify that additional heat in the plant environment from the EPU will not (1) interfere with required operator manual actions being performed at their designated time, or (2) require any new operator actions to maintain hot shutdown and then place the reactor in a cold shutdown condition.

In its response, the licensee stated that the effect of EPU process temperature and electrical heat load changes were evaluated for impact on normal area temperatures. Areas of the plant where operator manual actions are being performed for safe-shutdown following a fire were reviewed to determine if additional heat due to EPU conditions could adversely impact those defined operator actions. Areas requiring operator entry include various locations in the electric tunnels and in the control, turbine, reactor, and normal switchgear buildings. EPU conditions only impact the areas of the reactor building exposed to Residual Heat Removal (RHR) system process piping. The RHR process piping temperature increase is small and the maximum process piping temperature is bounded by the heat loss analysis assumption of 212 °F in the suppression pool; therefore, EPU does not impact operator actions.

The licensee's response satisfactorily addresses the NRC staff's concerns, and this RAI issue is considered resolved based on the following. For the EPU condition, the licensee reviewed plant areas where operator manual actions are being performed for safe-shutdown following a fire to determine if additional heat due to EPU conditions could adversely impact those defined operator actions. The licensee identified that the proposed EPU conditions only impact the areas of the reactor building exposed to RHR system process piping. The RHR process piping temperature increase is small and the maximum process piping temperature is bounded by the heat loss analysis assumption of 212 °F in the suppression pool. Based on its review, the NRC staff concludes that the proposed EPU does not impact current operator manual actions that will remain unchanged after EPU.

In RAI # D3, the NRC staff noted that Attachment 11 to NEDC-3335 IP Revision 0, Section 2.5.1.4, "Fire Protection," states that "...the results show that the peak fuel cladding temperature, reactor pressure and containment pressures and temperatures are below the acceptance limits and demonstrate that there is sufficient time for the operator to perform the necessary actions to achieve and maintain cold shutdown conditions...." The NRC staff requested the licensee to discuss the operator action response time, including any assumptions that may have been made in determining that the operator manual actions are feasible and reliable and can be accomplished to achieve and maintain hot and then cold shutdown conditions.

In its response, the licensee referred to the response to RAI#4, for hot shutdown which addresses operator action response time to achieve and maintain hot shutdown, including any assumptions made in determining that the operator manual actions are feasible and reliable. The response to this RAI # D3 only addresses the operator actions needed to achieve and maintain cold shutdown.

The licensee stated that after the plant is stabilized with adequate core cooling assured by using RCIC or pseudo LPCI, operator action is needed to bring the plant to cold shutdown using either normal shutdown cooling or alternate shutdown cooling. The licensee's Appendix R analysis makes the assumption that shutdown cooling is established at greater than 120 minutes from initiation of the fire. This assumption remains unchanged due to EPU. The actions needed to bring the plant to cold shutdown using the shutdown cooling mode of the RHR system are similar to those required under normal plant conditions from the control room. However, some of the actions require local operation instead of remote operation from the control room. These actions include:

If normal shutdown cooling is used:

- Local operation of Reactor Recirculation pump breakers: These actions are performed inside the north and south auxiliary bays of the reactor building on Elevation 240, and the east and west normal switchgear building on Elevation 261.
- Local power operation of Reactor Recirculation pump discharge valve 2RCS*MOV18B(A): This action is performed in the reactor building on Elevation 261.
- Local power operation of the LPCI injection valve 2RHS*MOV24A(B): This action is performed in the Division 1(2) switchgear rooms.
- Local manual verification that 2RHS*MOV24A(B) is closed: This action is performed on reactor building Elevation 289.

If alternate shutdown cooling is used:

- Local manual operation of 2RHS*MOV24A(B): This action is performed on reactor building Elevation 289.
- Local monitoring of SRV tail pipe temperatures: This action is performed in the control building, Elevation 261 west cable chase.

The licensee stated that while there are manual operator actions at various locations in the plant, these actions are feasible and reliable in terms of accessibility during an Appendix R fire event. The actions do not add significant operator action response time to reach cold shutdown from the hot shutdown condition. Analysis of Alternate Shutdown Cooling under EPU conditions concluded the system is capable of bringing the reactor from hot shutdown to cold shutdown conditions within approximately 50 hours which represents an approximately 16-hour increase in the time needed to reach cold shutdown and is within the Appendix R 72-hour cold shutdown requirement. The additional time is due to the increased decay heat load associated with EPU conditions. Since there are no changes to the operator actions for achieving cold shutdown, there is no difference in expected operator action response time.

The licensee's response satisfactorily addresses the NRC staff's concerns. The licensee indicated that manual operator actions at various locations in the plant are feasible and reliable in terms of accessibility during an Appendix R fire event. The actions do not add significant operator action response time to reach cold shutdown from the hot shutdown condition. The licensee identified that the analysis of alternate shutdown cooling under EPU conditions concluded the system is capable of bringing the reactor from hot shutdown to cold shutdown conditions within approximately 50 hours which represents an approximately 16-hour increase in the time needed to reach cold shutdown and is within the Appendix R 72-hour cold shutdown requirement.

In RAI # D4, the NRC staff noted that Attachment 11 to NEDC-3335 IP, Revision 0, Section 2.5.1.4.1, "10 CFR 50 Appendix R Fire Event," states that "...the results of Appendix R evaluation for current license thermal power (CLTP) and EPU provided in Table 2.5-1 and Figures 2.5-1 through 2.5-4 demonstrate that the fuel cladding integrity, reactor vessel integrity, and containment integrity are maintained and that sufficient time is available for the operator to perform the necessary actions...." The NRC staff requested the licensee to provide actual times for the operator to perform the necessary actions, including the anticipated "time margin" between when the actions are completed and when any thermal-hydraulic constraints are likely to be reached.

The licensee stated that in preparation for submittal of the LAR for EPU, NMPNS evaluated operator actions and response times needed to mitigate an Appendix R fire event. The performance objective is to achieve hot shutdown and then to achieve and maintain a cold shutdown condition. The licensee stated that their evaluation determined that no additional operator actions are required to meet the performance objective. For CLTP conditions, operators have demonstrated that the actions for the control room evacuation to achieve hot shutdown can be performed in 9 minutes, which is the time needed to initiate a reactor vessel blowdown from the Remote Shutdown panel and enable injection by operation of the LPCI system. The operator action time assumed by the licensee under EPU conditions is 10 minutes, which provides a 3.4 minute margin to the calculated time to reach the Minimum Steam Cooling Water Level (MSCWL) of -39 inches actual reactor water level. Fuel clad temperature remains well below 1500 °F with reactor water level at the MSCWL.

In the analysis for EPU, the basis for operator action time was changed from core submergence to steam cooling as the acceptance criteria for core cooling. Core submergence is defined as water level at TAF (-14 inches actual water level). MSCWL is defined as -39 inches actual water level. The change in acceptance criteria explains why the allowable operator action time is increased from 9 minutes to 13.4 minutes with no change in operator actions at EPU conditions.

In June 2006, the NRC independently observed a demonstration, by licensed operators, of a simulated transfer of plant control from the main control room to alternate safe shutdown panels, and a simulated plant shutdown to hot standby conditions from the remote shutdown panel. The team primarily focused on the portion of the procedures associated with achieving stable hot shutdown conditions within the time frames assumed in the safe shutdown thermal hydraulic analysis. The NRC team evaluated the approximate time to perform critical steps, such as establishing makeup flow to the reactor vessel, to assess the ability of operators to maintain plant parameters within the required limits. As documented in Nine Mile Point Nuclear Station Units 1 and 2 NRC Triennial Fire Protection Inspection Reports 05000220/2006006 and 05000410/2006006, dated July 6, 2006, no findings of significance were identified by the NRC during this inspection.

In June 2009, the NRC independently confirmed that NMP2 operators are able to meet the assumed action times to maintain effective reactivity control, reactor coolant makeup, reactor decay heat removal, process monitoring instrumentation, and support systems functions during a shutdown from outside the control room with and without the availability of offsite power. This is documented in Nine Mile Point Nuclear Station Units 1 and 2 NRC Triennial Fire Protection Inspection Reports 05000220/2009006 and 05000410/2009006 and Exercise of Enforcement Discretion, dated August 3, 2009.

The following is an excerpt from the 2009 inspection report:

> The [NRC] team verified that the training program for licensed and non-licensed operators included alternative shutdown capability. The team also verified that personnel required for safe shutdown using the normal or alternative shutdown systems and procedures are trained and available onsite at all times, and were exclusive of those assigned as fire brigade members.
>
> The [NRC] team reviewed the adequacy of procedures utilized for post-fire safe shutdown and performed an independent walk through of procedure steps to ensure the implementation and human factors adequacy of the procedures. The team also verified that the operators could be reasonably expected to perform specific actions within the time required to maintain plant parameters within specified limits. Time critical actions, which were verified, included the restoration of alternating current (AC) electrical power, establishing the remote shutdown and local shutdown panels, establishing reactor coolant makeup, and establishing decay heat removal.

While the referenced NRC inspection reports are based on current licensed power conditions, the assessment remains valid since there are no changes to required operator actions and the operator action time is longer at EPU conditions.

The licensee's response satisfactorily addresses the NRC staff's concerns, and this RAI issue is considered resolved based on the following: The licensee stated that in preparation for submittal of the LAR for EPU, they evaluated operator actions and response times needed to mitigate an Appendix R fire event. The performance objective is to achieve hot shutdown and then to achieve and maintain a cold shutdown condition. This includes changing the acceptance criterion from TAF to MSCWL which is a change in acceptance criteria from water level never going below TAF to assurance that no fuel perforation occur. This criterion has been approved by the NRC staff in a memo dated December 3, 1982, for the Boiling Water Reactor licensees (ADAMS Accession No. ML100770395).

The licensee has calculated thermal-hydraulic time when thermal-hydraulic constraint is reached under TAF (9 minutes) versus the time when thermal-hydraulic constraint is reached under MSCWL (13.4 minutes). The results of the calculation show that time to reach the thermal-hydraulic constraint is increased from 9 minutes (under TAF criterion) to 13.4 minutes (under MSCWL criterion) with no change in operator manual actions. The evaluation determined that any changes to existing operator actions that will remain under EPU are minimal and that no additional operator actions are required to meet the performance objective. Based on its review, the NRC staff concludes that the proposed EPU does not impact operator manual actions.

In RAI # D5, the NRC staff noted that the results of the Appendix R evaluation for CLTP and EPU are provided in Table 2.5-1 and Figures 2.5-1 through 2.5-4. The NRC staff noted in Table 2.5-1 that at EPU condition, there is an increase in the suppression pool bulk temperature to 198.1 °F, 9.5 °F above the current suppression pool bulk temperature of 188.6 °F. The NRC staff requested the licensee to identify whether NMP2 safe shutdown instructions credit any operator manual action in the secondary containment. If any, the NRC staff requested the licensee to discuss how this operator manual action can be accomplished within the available time at higher suppression pool bulk temperature (e.g., manually opening the main steam relief valves). In addition, the NRC staff requested that the licensee verify if a LPCI pump is used for safe shutdown, and if so, how does NMP2 ensure adequate net positive suction head (NPSH) available to the LPCI pump throughout the Appendix R event.

The licensee stated that the NMP2 safe shutdown instructions do credit operator manual actions in the secondary containment (i.e., reactor building). The effects of EPU process temperature and electrical heat load changes, including the increase in suppression pool bulk temperature, were evaluated for impact on secondary containment area temperatures. The electrical heat load is the dominant heat load and is unchanged by EPU. The heat load from the process pipe temperatures represents 17 percent of the total for the RHR pump rooms. The EPU decay heat increases the maximum suppression pool temperature by 9.5 °F; however the design analysis bounds the 9.5 °F increase because it assumed a design temperature of 212 °F in the suppression pool. Therefore, operator manual actions in the secondary containment credited for safe shutdown are not impacted by the increase in suppression pool bulk temperature.

The licensee stated that low-pressure coolant injection (LPCI) is used for safe shutdown for NMP2. Adequate NPSH is ensured for the increase in suppression pool bulk temperature under EPU conditions since the NPSH calculations use a suppression pool bulk temperature of 212 °F, at atmospheric pressure, which bounds the EPU suppression pool bulk temperature.

The licensee's response satisfactorily addresses the NRC staff's concerns, and this RAI issue is considered resolved based on the following: The licensee stated that safe shutdown instructions credit operator manual actions in the secondary containment, i.e., reactor building. Further, the licensee indicated that in secondary containment the dominant heat load is due to the electrical heat load and is unchanged at EPU conditions. Further, the licensee identified at EPU conditions decay heat increases the maximum suppression pool temperature by 9.5 °F and their design analysis bounds the 9.5 °F increase because it assumed a design temperature of 212 °F in the suppression pool. Therefore, manual actions credited for safe shutdown are not impacted by the increase in suppression pool bulk temperature.

The licensee concluded that the adequate NPSH available to the LPCI pump, based on the bounding analysis, i.e., suppression pool bulk temperature of 212 °F (at atmospheric pressure) bounds the EPU suppression pool bulk temperature 198.1 °F. Therefore, NPSH to the LPCI pump throughout the Appendix R event will not be affected by the EPU.

In RAI # D6, the NRC staff stated that some plants credit aspects of their fire protection system for other than fire protection activities, e.g., utilizing the fire water pumps and water supply as backup cooling or inventory for non-primary reactor systems. If the NMP2 credits its fire protection system in this way, the NRC staff requested that EPU LAR identify the specific situations and discuss to what extent, if any, the EPU affects these "non-fire-protection" aspects of the plant fire protection system. If the NMP2 does not take such credit, the NRC staff requested that the licensee verify this as well.

The licensee stated that NMPNS does not credit the fire protection system to support the design basis for non-fire protection functions at NMP2.

The licensee's response satisfactorily addresses the NRC staff's concerns, and this RAI issue is considered resolved based on the following: the licensee indicated that the fire protection system is not credited for any non-fire protection function to support a design basis event.

The information provided in the LAR, as supplemented by the response to NRC staff RAIs, satisfactorily demonstrates that compliance with the fire protection and safe shutdown program will not be affected. Furthermore, the licensee's EPU evaluation did not identify changes to design or operating conditions that will impact the post-fire safe shutdown capability. The EPU does not change the credited equipment necessary for post-fire safe shutdown nor does it require reroute of essential cables or relocation of essential components/equipment credited for post-fire safe shutdown. The licensee has made no changes to the plant configuration or combustible loading as a result of modifications necessary to implement the EPU that affect the NMP2 fire protection program.

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 15 percent increase in decay heat on the ability of the required systems to achieve and maintain safe-shutdown conditions. The NRC staff finds this aspect of the capability of the associated SSCs to perform their design basis functions at an increased core power level of 3988 MWt acceptable with respect to fire protection.

2.5.2 Fission Product Control

2.5.2.1 Fission Product Control Systems and Structures

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 EPU conditions. Consequently, the NRC staff's review focuses primarily on any adverse effects that the proposed EPU might have on the assumptions that were used in analyses that were previously completed. Because the impact of EPU on plant systems and structures identified by the licensee as making up the fission product control system are addressed in Section 2.6, "Containment Review Considerations," Section 2.7, "Habitability, Filtration, and Ventilation," and Section 2.9, "Source Terms and Radiological Consequences," a separate evaluation in this section is not required.

2.5.2.2 Main Condenser Evacuation System

Regulatory Evaluation

The main condenser evacuation system (MCES) generally consists of two subsystems: (1) the startup system which initially establishes main condenser 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: (1) GDC-60, insofar as it requires that the plant design include means to control the release of radioactive effluents; and (2) 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 anticipated operational occurrences and postulated accidents.

Technical Evaluation

The licensee indicated during its review of the MCES that the design of the condenser air removal system will not be adversely affected by EPU and no modification to the MCES will be required. The licensee evaluated three areas of the condenser air removal system to make its assessment:

- Non-condensable gas flow capacity of the steam jet air ejectors (SJAEs) system;
- Capability of the SJAEs to operate satisfactorily with available dilution/motive steam flow;
- Mechanical vacuum pump capability to remove required non-condensable gases from the condenser at EPU start-up conditions.

The licensee indicated that the physical size of the primary condenser and evacuation time remain unchanged in establishing the capabilities of the vacuum pumps under EPU conditions. Also, the licensee indicated the holdup time in the pump discharge line does not change and the SJAEs are capable for handling operational flows at EPU conditions.

The NRC staff reviewed the licensee's assessment for the MCES according to GDC-60 and GDC-64 and initially found that the system appeared to be capable of handling EPU operation without any prescribed changes. However, in the licensee's conclusion for the MCES assessment in the LAR, the licensee mentioned that there were required changes to the MCES that were evaluated. The NRC staff issued an RAI, dated December 23, 2009, on what type of changes that the licensee was referring to for the MCES. The licensee responded in its RAI response, dated February 19, 2010, that the changes were in reference to the operational parameters for the SJAEs during EPU conditions and not hardware modifications. The licensee stated that these changes would allow the SJAEs to continue to function in the manner that would allow the MCES to continue to meet GDC-60 during EPU operation. The NRC staff is satisfied with the licensee's clarification and found its assessment of the MCES to be acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the MCES and concludes that the licensee has adequately evaluated these changes. The NRC staff concludes that the MCES will continue to maintain its ability to control and provide monitoring for releases of radioactive materials to the environment following implementation of the proposed EPU. The NRC also concludes that the MCES will continue meet the requirements of GDC-60 and GDC-64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MCES.

2.5.2.3 Turbine Gland Sealing System

Regulatory Evaluation

The turbine gland sealing system (TGSS) is provided to control the release of radioactive material from steam in the turbine to the environment. The NRC staff reviewed changes to the TGSS with respect to factors that may affect gaseous radioactive material handling (e.g., source of sealing steam, system interfaces, and potential leakage paths). The NRC's acceptance criteria for the TGSS 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-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 anticipated operational occurrences and postulated accidents.

Technical Evaluation

The licensee evaluated the TGSS and initially found that no modifications are needed to support EPU conditions. By letter dated September 23, 2011, the licensee stated that a later evaluation determined that the calibrated span of the normal gland seal supply pressure indication instrument loop will need to be increased and the alarm setpoint revised. The NRC staff did not find any concerns with the licensee's assessment with the TGSS and that the functionality of the TGSS during EPU operations should continue to meet the criteria of GDC-60 and GDC-64. Therefore, the NRC staff finds the TGSS acceptable for EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment 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 ability to control and provide monitoring for releases of radioactive materials to the environment consistent with GDC-60 and GDC-64. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the turbine gland sealing system.

2.5.3 Component Cooling and Decay Heat Removal

2.5.3.1 Spent Fuel Pool Cooling and Cleanup System

Regulatory Evaluation

The spent fuel pool (SFP) provides wet storage of spent fuel assemblies. The safety function of the SFP cooling and cleanup system 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 EPU focused on the effects of the proposed EPU 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 SFP cooling and cleanup system 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.

Technical Evaluation

The licensee used Section 6.3 of the CLTR to address the effect of EPU on the SFP. The licensee indicated that the NMP2 spent fuel pool cooling and cleanup system (SFPCCS) and the supporting systems are not interconnected with NMP1 and will continue to remain that way for EPU operation. The spent fuel cooling section of the SFPCCS is classified as nuclear safety related and is redundant. Cooling water to the SFPCCS heat exchangers is provided by the reactor building closed loop cooling water (RBCCW) or service water systems (SWS). Additional SFPCCS cooling is available from the RHR system. The SWS is redundant and classified as nuclear safety related. The licensee stated that EPU conditions will not affect the alignments, availability or safety related designations of these systems, nor change the trains of cooling used to evaluate the effects of core offload.

The current thermal licensing basis for the NMP2 SFP is to maintain the SFP bulk water temperature at or below 125 °F under normal operating conditions, below 140 °F for a normal full-core offload, and below 150 °F for emergency core offload. In addition, the SFPCCS is designed to maintain an average reactor coolant exit temperature below 150 °F during plant refueling outages. The licensee stated that the proposed EPU will increase the heat load on the SFPCCS during and after refueling outages because of the increase in decay heat. The increased decay heat was evaluated for batch and full core offloads. For the months December through April, when refueling outages are expected to take place, the maximum expected service water temperature is approximately 50 °F, while the heat removal by the SFPCCS heat exchanger is based on a temperature of 52 °F. The emergency full-core offload was also evaluated by the licensee with the maximum service water temperature of 84 °F.

The licensee concluded from its assessment of the SFPCCS that the additional heat load due to EPU is within the SFPCCS design basis capability, and does not adversely affect system components or functions. The licensee will use existing administrative and procedural limitations to maintain the increased decay heat within SFPCCS design limits for the full-core offload during a normal refueling outage. The NRC staff requested additional clarification in the December 23, 2009, letter to the licensee regarding what these administrative and procedural limitations are and how they will be used to maintain the SFPCCS within design limits for full-core offload during EPU operation. The licensee responded in the February 19, 2010, letter to the NRC that the heat load to the SFP is controlled by delaying the initiation of core offload to reduce the decay heat in the fuel and by controlling the rate of core offload. The capability of the SFP to reject the required heat load is controlled by the licensee scheduling refueling outages during specific times of the year to ensure that SWS temperatures from Lake Ontario, used as the UHS for NMP2, are below calculated limits and by specifying minimum SFP equipment functionality requirements.

The licensee also referenced peak SFP temperature values in the LAR for post-EPU full-core offloads and core shuffles. The temperatures provided assume core offload delays of 48 or 80 hours. Current operating and fuel-handling procedures control the required delay time in commencing offload, as well as the allowed offload rate (number of bundles per hour). The analysis supporting these values listed in the LAR is contained in an engineering calculation, which also includes consideration of maximum expected SWS temperatures. The licensee will revise both this calculation for the higher EPU core thermal power and the associated procedures, as necessary, in maintaining control of SFP decay heat load to ensure SFP temperatures remain within design basis requirements of the SFPCCS for EPU operation.

The licensee stated in the LAR that no changes will be required to the SFP to accommodate the emergency full-core offload. NMP2 USAR Section 9.1.3 describes the SFPCCS operation during normal refueling, normal full-core offload, and full-core emergency offload conditions. This section states that due to the time available for required operator actions following a faulted (i.e., line break) condition and the redundancy of the SFPCCS system, SFPCCS is assured for any single active or passive failure. The licensee also stated in the LAR that the maximum temperatures with available cooling will remain within the limits described in the NMP2 USAR. The heating rate is sufficiently slow to allow operator actions to initiate a redundant cooling system. In the event of a complete loss of cooling to the pool, the boil-off rates remain within the make-up capability. The licensee indicated that the radiation levels around the SFP could increase to about 20 percent due to EPU, but it will have a very minimal effect on plant operation. The current NMP2 radiation procedures and radiation monitoring program would detect any changes in radiation levels and initiate appropriate actions. The licensee concludes in its overall assessment of the SFP that the SFPCCS system remains capable of performing its required safety functions after EPU implementation.

The NRC staff has reviewed the licensee's assessment of the SFP for EPU operation according to GDC-5, GDC-44, and GDC-61. The NRC staff is satisfied with the licensee's assessment, in which: (1) the SFP for NMP2 will continue to be used for NMP2 only after EPU implementation; (2) the SFP will continue to have the capability to transfer heat loads from safety related SSCs to the UHS; and (3) the SFP will continue to handle decay heat removal for EPU conditions. Therefore, the NRC staff finds the licensee's assessment of the SFP acceptable for EPU operation.

Conclusion

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

2.5.3.2 Station Service Water System

Regulatory Evaluation

The 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

EPU. 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.

Technical Evaluation

The licensee used Section 6.4 of the CLTR to address the effect of the EPU on the SWS. The LAR describes the SWS as providing once through cooling water from Lake Ontario to various safety related and non-safety related plant systems and components in NMP2. The SWS is designed to operate during normal, transient and post accident conditions. The safety related portion of the SWS includes the pumps and (safety related to non-safety related) isolation valves along with the Division I and Division II headers in the Reactor and Control Buildings, divisional supplies to the emergency diesel generator (EDG) building, service water pump bays in the screenwell building and the UHS. The non-safety related portions of SWS include the turbine building supply and return, RBCCW heat exchangers and reactor building normal HVAC supply air cooling coil. The licensee provided a list of essential components and systems, indicated as safety related loads in the LAR, that utilize the safety-portions of the SWS for cooling water during and following a design-basis accident (DBA). The licensee indicated that these components and systems are not impacted by the reactor thermal power (RTP); therefore EPU will not affect their capabilities to perform their current safety functions as designed.

The licensee evaluated the effect of the EPU operation on the residual heat removal system (RHR) and SFP cooling water heat exchangers by performing the containment cooling analysis of the increased RHS heat load in the suppression pool following a loss-of-coolant accident (LOCA). In Section 2.6, "Containment Review Considerations," the licensee's assessment of the containment cooling is addressed in more detail. The licensee concluded in its assessment of the containment cooling under EPU operation that the cooling capability of the SWS is adequate to maintain the suppression pool temperature within acceptable design limits following a LOCA. The licensee also determined that the SWS is capable of providing adequate cooling and makeup for the SFP and its cooling water heat exchangers and that the SWS has sufficient capacity for long-term core and containment cooling at EPU conditions. In addition to the analysis for the safety related portion of the SWS, the licensee also indicated four unit coolers are being added in the turbine building for the condensate and condensate booster pumps that will support increased heat loads from EPU operation. The unit coolers will increase SWS flow by approximately 1 percent, but will have a minimal impact on the overall SWS flow distribution and heat removal capability.

The NRC staff reviewed the licensee's assessment of the SWS according to GDC-4, GDC-5, and GDC-44 and finds that the impact of EPU operation on the systems and components that utilize the SWS will not affect their capabilities to perform their safety functions, especially in the event of accident scenarios such as a LOCA. The current design features of the SWS have been evaluated by the licensee to show that the increased decay heat can be maintained within limits without any modifications to the SWS, particularly with the RHS and SFP cooling water heat exchangers. The NRC staff finds the licensee's assessment acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the SWS and concludes that the licensee has adequately accounted for the increased heat loads on system performance that would result from the proposed EPU. The NRC staff concludes that the SWS 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 EPU. Therefore, the NRC staff has determined that the station SWS will continue to meet the requirements of GDC-4, GDC-5, and GDC-44. Based on the above, the NRC staff finds the proposed EPU acceptable with respect to the station SWS.

2.5.3.3 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, anticipated operational occurrences, 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 emergency core cooling system (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 EPU. 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.

Technical Evaluation

The licensee used Section 6.4 of the CLTR to addresses the effect of the EPU on the reactor auxiliary cooling water systems. The two systems evaluated in the LAR for EPU operation are the RBCCW system and the turbine building closed loop cooling water system (TBCCW).

The RBCCW heat loads are mainly dependent on the reactor vessel temperature and/or flow rates in the systems cooled by the RBCCW. However, neither of these items is affected by the proposed EPU. The licensee described in the LAR that the only significant increase in heat load due to EPU is an increase in SFP cooling heat load. The safety related cooling for the SFP is provided by the SWS and not the RBCCW system. The normal heat load from the SFP is 16 MBTU/hr. This load would increase by less than 20 percent, which is a small fraction of the RBCCW system design heat load of 73.6 MBTU/hr. The SFP cooling heat load occurs during refueling when other RBCCW loads are offline or significantly reduced. Therefore, the licensee concluded that the increase in SFP cooling heat load will not increase the RBCCW system heat loads beyond system design. The licensee's assessment of the RBCCW system contains redundancy in pumps and heat exchangers to ensure that adequate heat removal capability is available during normal operation and available to accommodate the small increase in heat load due to EPU.

For the TBCCW system, the supply temperature is dependent on the heat rejected to the TBCCW system through the components cooled by the system, as removed by the TBCCW heat exchangers and controlled by the system temperature control valve(s). Some heat loads on the TBCCW system are power-dependent and are increased by the EPU, such as those related to the power train pumps (condensate pumps, condensate booster pumps, heater drain pumps, reactor feed pumps) and turbine auxiliaries (generator hydrogen coolers, generator stator water coolers, generator leads coolers (bus duct cooling), and exciter alternator coolers). The licensee's analysis in the LAR provided a value of the heat load for the total TBCCW system, which is 109.6 MBTU/hr, for EPU conditions. The normal capacity for the TBCCW system is 129 MBTU/hr, which will not be impacted by EPU operation. The licensee concluded that the increase in heat load of the TBCCW system can be accommodated by the margin in the system heat exchangers.

The NRC staff reviewed the licensee's assessment of both subsystems for the reactor auxiliary cooling water system according to GDC-4, GDC-5, and GDC-44 and found that the effects on the water subsystems will not impact their current ability to perform their functions and not affect the SSCs from performing their safety functions during EPU conditions. The NRC staff finds the licensee's assessment acceptable since no physical modifications are required for both subsystems to support EPU operation and the overall reactor auxiliary cooling water system design is capable to handle the minimal increased heat load.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the reactor auxiliary cooling water systems and concludes that the licensee has adequately accounted for the increased heat loads from the proposed EPU 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 EPU. Therefore, the NRC staff has determined that the reactor auxiliary cooling water systems will continue to meet the requirements of GDC-4, GDC-5, and GDC-44. Based on the above, the NRC staff finds the proposed EPU acceptable with respect to the reactor auxiliary cooling water systems.

2.5.3.4 Ultimate Heat Sink

Regulatory Evaluation

The 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 EPU 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.

Technical Evaluation

The licensee used Section 6.4 of the CLTR to address the effect of the proposed EPU on the UHS. The UHS for NMP2 is designated as Lake Ontario. The UHS is designed to supply water at 84 °F from the lake and to return water to the lake at a temperature less than the State Pollutant Discharge Elimination System (SPDES) limit of 110 °F. The SPDES permit also limits the temperature differential between the discharge and suction to less than 30°F. As a result of operation at the EPU RTP level, the licensee's analysis shows that the discharge temperature and temperature differential will increase due to higher heat loads. The normal operation discharge temperature is 98 °F for CLTP and 100 °F for EPU, a differential of plus 2 °F. For the LOCA scenarios, the discharge temperature for CLTP and EPU is 126 °F, which indicates no change for EPU operation. The licensee conducted a review to evaluate the increased UHS heat load for the EPU. The licensee concluded that the temperature of the discharge water and the differential temperature between the intake and discharge are within the limit set by the State of New York for normal and shutdown conditions. For LOCA conditions, the temperatures will exceed the SPDES limit, but the permit allows the limits to be exceeded under emergency conditions.

The NRC staff has reviewed the licensee's assessment of the UHS according to GDC-5 and GDC-44 and does not see any major implications that would impact the UHS from performing its safety functions during EPU operation. No modifications are needed for the UHS to support normal and accident conditions during EPU operation; therefore, the NRC staff finds the licensee's assessment acceptable and no further evaluation of the UHS is needed.

Conclusion

The NRC staff has reviewed the information that was provided by the licensee for addressing the effects that the proposed EPU 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 EPU will not compromise the design-basis safety function of the UHS, and that the UHS will continue to satisfy the requirements of GDC-5 and GDC-44 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the UHS.

2.5.4 Balance-of-Plant Systems

2.5.4.1. Main Steam

Regulatory Evaluation

The main steam supply system (MSSS) transports steam from the reactor 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 EPU 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 protected against dynamic effects, including the effects missiles, pipe whip, and jet impingement forces associated with pipe breaks; and (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.

Technical Evaluation

The licensee used Sections 3.4.1 and 3.7 of the CLTR to address the effect of proposed EPU on flow induced vibration in the main steam line and main steam line flow restrictors. The licensee indicated that the main steam (MS) piping pressures and temperatures are not affected by EPU. The licensee also indicated that seismic inertia loads, seismic building displacement loads, and SRV discharge loads are not affected by EPU. The increase in MS flow results in increased forces from the turbine stop valve closure transient. However, the turbine stop valve closure loads bound the MSIV closure loads because the MSIV closure time is significantly longer than the turbine stop valve closure time.

The licensee stated in the LAR that NMP2 has a monitoring program for safety relief valve (SRV) leakage. A monthly procedure is performed to trend SRV tail pipe temperatures. The licensee has performed analyses and testing for NMP2, which investigated and addressed the potential for acoustic resonance due to the increased steam flow past the SRV standpipes, as well as other branch connections. The licensee concluded that the onset of SRV standpipe vortex shedding acoustic resonance could be expected at MS flow rates approximately 40 percent above the proposed EPU 100 percent power steam flow rates. Therefore, the licensee concluded that SRV vibration resulting from acoustic resonance is not expected at the EPU operating conditions. The licensee also stated that the existing SRV leakage monitoring instrumentation should be capable to detect any increased SRV leakage during EPU conditions.

The licensee also assessed the MSSS for increased main steam line (MSL) flow, which may affect vibration of the piping during normal operation. The vibration frequency, extent, and magnitude depend upon plant-specific parameters, valve locations, the valve design, and piping support arrangements. The flow-induced vibration (FIV) of the piping will be addressed by vibration testing during initial plant operation at the higher steam flow rates for EPU operation. The licensee included in Attachment 10 of the LAR details of the vibration monitoring program. The licensee concluded that [[

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The NRC staff reviewed the licensee's assessment of the MSSS according to GDC-4 and GDC-5 and did not find any implications that would allow the MS system to negatively impact the SSCs important to safety at EPU conditions. The current analysis for normal and accident scenarios remain unchanged for EPU conditions and no modifications to the MS system is needed to support EPU operation. Therefore, the NRC staff finds the licensee assessment of the MS acceptable for EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU 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 GDC-4 and GDC-5. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MSSS.

2.5.4.2 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). For plants without an MSIV leakage control system, the MC system may also serve an accident mitigation function to act as a holdup volume for the plateout of fission products leaking through the MSIVs following core damage. The NRC staff's review focused on the effects of the proposed EPU 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 turbine steam bypass system (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.

Technical Evaluation

The licensee used Section 7.2 of the CLTR to address the effect of the proposed EPU on the MC. EPU operation increases the heat and pressure rejected to the MC from the TBS and, therefore, reduces the difference between the operating pressure and the recommended maximum MC pressure. If the MC pressures approach the main turbine backpressure limitation, then RTP reduction would be required to reduce the heat rejected to the condenser and maintain MC pressure within the main turbine requirements. The licensee stated that the MC, circulating water, and cooling tower systems are not being modified for EPU operation. The licensee evaluated the performance of these systems for EPU operation based on a design duty over the actual range of circulating water inlet temperatures. The licensee concluded that the MC, circulating water system, cooling tower are adequate for EPU operation. The licensee also stated that EPU operation decreases the margin for the MC storage capacity from 7.75 minutes at CLTP to 6.55 minutes at EPU. MC storage capacity remains greater than the required 5 minute holdup time for the decay of short-lived radioactive isotopes. The absolute value in lbm/hr of the steam bypassed to the main condenser during a load rejection event is not increased for EPU.

The NRC staff evaluated the licensee's assessment of the MC system according to GDC-60 and found that the MC will continue to perform its function in controlling the release of radioactive effluents within the system's design capability. No changes are being made to the MC to support EPU operation and the MC ability to handle increased heat due to EPU operation remains within system design capability. Therefore, the NRC staff finds the licensee's assessment of the MC system acceptable for EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU 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 with respect to controlling releases of radioactive effluents. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the MC system.

2.5.4.3 Turbine Steam Bypass System

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 reactor pressure. For a plant without an MSIV leakage control system, the TBS could also provide an accident mitigation function. A TBS, along with the MSSS and MC system, may be credited for mitigating the effects of MSIV leakage during a LOCA by the holdup and plateout of fission products. The NRC staff's review for the TBS focused on the effects that the proposed EPU have on load rejection capability, analysis of postulated system piping failures, and 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 designed to accommodate the effects of and to be compatible with the environmental conditions associated with normal operation, maintenance, testing, and postulated accidents (including pipe breaks or malfunctions of the TBS), and (2) GDC-34, insofar as it requires that a RHR system be provided to transfer fission product decay heat and other residual heat from the reactor core at a rate such that specified acceptable fuel design limits (SAFDL) and the design conditions of the RCPB are not exceeded.

Technical Evaluation

The licensee used Section 7.3 of the CLTR to address the effect of proposed EPU on the TBS. The licensee described the TBS as a means of accommodating excess steam generated during normal plant maneuvers and transients. The credited bypass capacity of 3,260,000 lbm/hr (unchanged from CLTP) is used as an input to the reload analysis process for the evaluation of limiting events that credit the TBS. Each of five bypass valves is designed to pass a steam flow of 836,000 lbm/hr (4,180,000 lbm/hr total). The bypass capacity at NMP2 remains adequate for normal operational flexibility at EPU rated thermal power.

The NRC staff evaluated the licensee's assessment of the TBS according to GDC-4 and GDC-34 and did not find any system modifications or changes to the operation of the TBS that would be impacted by EPU implementation. The TBS capability to handle steam bypass from the turbine remains unchanged for EPU conditions. The NRC staff finds the licensee's assessment of the TBS acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU 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 TBS. The NRC staff concludes that the TBS failures will not adversely affect essential SSCs. Based on this, the NRC staff concludes that the TBS will continue to meet GDC-4 and GDC-34. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the TBS.

2.5.4.4 Condensate and Feedwater System

Regulatory Evaluation

The condensate and feedwater system (CFS) provides feedwater at a particular temperature, pressure, and flow rate to the reactor. The only part of the CFS classified as safety related is the feedwater piping from the reactor up to and including the outermost containment isolation valve. The NRC staff's review focused on how the proposed EPU affects previous analyses and considerations with respect to the capability of the CFS to supply adequate feedwater during plant operation and shutdown, and isolate components, subsystems, and piping in order to preserve the system's safety function. 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 including possible fluid flow instabilities (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, and that the system be provided with suitable isolation capabilities to assure the safety function can be accomplished with electric power available from only the onsite system or only the offsite system, assuming a single failure.

Technical Evaluation

The licensee described the CFS in the LAR as being able to provide a reliable supply of FW at the temperature, pressure, quality, and flow rate as required by the reactor. The performance of the CFS has a major effect on plant availability and capability to operate at EPU conditions. In the LAR, the licensee listed non-safety related equipment that will be modified to support EPU operation, which include:

- Feedwater Heater 6 Shell Side Safety Valve Replacement
- Feedwater Heater 5 Shell Side Design Pressure Re-Rating
- Feedwater Heater 6 Shell and Tube Side Design Pressure Re-Rating
- Heater Drain Pump and Motor Replacement
- Heater Drain Level Control Valve Replacement
- Reactor Feedwater Pump Impeller Replacement and Modification
- Reactor Feedwater Pump Motor Cable Replacement
- Reactor Feedwater Pump Speed Increaser Replacement
- Reactor Feedwater Pump Flow Control Valve Modifications
- Feedwater System Design Pressure Re-Rating
- Revise Recirculation Runback Logic to initiate on a Feedwater/Condensate Booster Pump Trip and increase Runback Rate to 9 percent per second
- Feedwater System Setpoint Setdown
- Moisture Separator Reheater Shell Side Design Pressure Re-Rating
- Moisture Separator Reheater Drain Receiver Design Pressure Re-Rating
- Building Heating Intermediate Heat Exchanger Design Pressure Re-Rating
- Scavenging Steam Relief Valve Replacement
- Cross Around Relief Valve Replacement
- Cross Around Piping Re-Rating

The licensee also listed the following equipment being modified due to current material condition, but also prior to EPU implementation:

- Replacement of Extraction Steam Expansion Bellows for the 1st through 4th Point Feedwater Heater Extraction Steam Lines on the 'B' and 'C' Lines
- Replacement of the 3rd Point Feedwater Heaters

The licensee evaluated the CFS for normal operation and transient operation at EPU conditions. At normal operation, the licensee projected that the CFS will produce operating flows at approximately 118 percent of rated flow at the CLTP for EPU conditions. The modifications listed above are being made to the CFS to ensure that the system can perform its current functions provided that three condensate pumps, three condensate booster pumps, three heater drain pumps, and two reactor feedwater pumps are in operation. The licensee also reviewed and verified that the current FW heater design can withstand higher FW heater flows, temperatures, and pressures for EPU operation. The licensee will monitor the performance of the FW heaters during the EPU power ascension program.

For transient operation, the licensee evaluated the FW system and determined the FW system to have approximately 7 percent margin at EPU FW flow. For system operation with all CFS system pumps available, the licensee projected that the operating parameters were acceptable and within the component capabilities to support transients at EPU conditions. The licensee also evaluated the condensate pumps, condensate booster pumps, and feed pump trip system capacity and found that with the modifications listed above, the equipment will be capable to supply transient flow requirements. However, the licensee found in its evaluation of the modifications to the CFS that the condensate booster pumps trip system capacity will have insufficient capacity to maintain the required suction pressure on the reactor feed pump. Consequently, a condensate booster pump trip will require a reduction in plant power level. Therefore, the licensee plans to modify the reactor recirculation runback (RRRB) logic for EPU operation to initiate not only on a reactor feedwater pump trip, but also on a condensate booster pump trip. The licensee stated that this modification to the RRRB logic will provide additional protection against multiple FW pumps tripping from a single or common initiating event at EPU conditions. In conjunction with the RRRB logic changes, the licensee stated that the low suction pressure FW and condensate booster pump trips will be staggered to allow one FW pump to continue to operate, regain suction pressure and clear any low alarm signals which would otherwise trip the operating pump. The licensee stated that these additional changes to the CFS trip logic provide equipment protection while reducing the likelihood of a single or common initiating event resulting in the loss of multiple pieces of equipment from service. The post-heater drain pump trip system capacity was also evaluated by the licensee using the modifications listed above and found to be sufficient to meet the transient flow requirement. Additionally, the licensee evaluated the effect of the EPU on the condensate filter demineralizers (CFDs) and found that the CFD is capable of performing its functions during EPU conditions.

The NRC staff evaluated the licensee's assessment of the CFS according to GDC-4, GDC-5, and GDC-44 and found that the EPU operation will not prevent the CFS from performing its normal and transient functions, provided that the licensee makes the evaluated changes to the CFS equipment prior to EPU implementation. The modifications to the CFS do not prevent the system from withstanding a water hammer or lead to the failure of SSCs important to safety. NMP2 also will maintain its isolation capacity to preserve the system safety function. The NRC staff finds the licensee's assessment of the CFS acceptable for EPU operation.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU 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 GDC-4, GDC-5, and GDC-44. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the CFS.

2.5.5 Waste Management Systems

2.5.5.1 Gaseous Waste Management Systems

Regulatory Evaluation

The 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 gland seal exhaust and the mechanical vacuum pump operation exhaust; and the building ventilation system exhausts. The NRC staff's review focused on the effects that the proposed EPU may have on (1) the design criteria of the GWMS; (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 exists. The NRC's acceptance criteria for gaseous 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-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 to meet the "as low as is reasonably achievable" (ALARA) criterion.

Technical Evaluation

The licensee used Section 8.2 of the CLTR to address the effects of proposed EPU on the GWMS. The licensee described in the LAR that the primary function of the GWMS is to process and control the release of gaseous radioactive effluents to the site environs so that the total radiation exposure of persons in offsite areas is within the guideline values of 10 CFR Part 50, Appendix I. The GWMS involves the management of the condenser air removal system, gland seal exhaust and mechanical vacuum pump operation exhaust. The licensee has plant procedures in place at NMP2 to test for air infiltration and repair as needed to maintain the offgas system as functional.

The CLTP design basis off-gas flow rate is 0.067 cfm/MWt. The normal operation off-gas flow rate is expected to increase by approximately 15 percent due to EPU. The licensee determined that the CLTP design basis will be maintained for EPU operation and that all structures, systems, and components of the offgas system were acceptable for EPU operation.

The licensee stated in the LAR that the GWMS also have methods of treatment for radiological releases consisting of holdup and filtration to reduce the gaseous radioactivity that could be potentially released to offsite areas. These methods of treatment are applied to the condenser offgas system and TGSS. The condenser offgas system radiological release rate is a function of fuel cladding performance, main condenser air in leakage, charcoal absorber inlet dew point, and charcoal absorber temperature, all of which are unaffected by the proposed EPU. The licensee determined that both the condenser offgas system and the TGSS (as described in Section 2.5.2.3 of this SE) will maintain their capability to perform their design functions for EPU operation. The current NMP2 TS requirements to limit fission gas releases to the environment are represented in plant procedures for reducing power; identifying and suppressing power near leaking fuel, and repairing condenser air in leakage to maintain the offgas limits. These plant procedures are not affected by EPU.

The licensee also stated that the GWMS design criteria will ensure that it will meet the plant licensing basis for controlling gaseous waste such that the total radiation exposure of persons in offsite areas will be within the applicable guideline values of 10 CFR 20.1302; 10 CFR Part 50, Appendix I; and 40 CFR Part 190. The licensee's plant gaseous waste licensing basis and the

GWMS design criteria that support the licensing basis for NMP2 are unchanged by the EPU, and the plant will continue to satisfy this licensing basis under EPU operating conditions. The licensee also addressed the combustible gas control component design requirements, which are determined by the quantity of radiolytic hydrogen and oxygen, which are expected to increase in proportion to the EPU power increase. However, the licensee's evaluation concluded that the offgas system has sufficient margin to handle the increase of the radiolytic hydrogen and oxygen for EPU operation and ensure that the GWMS will continue to satisfy the current plant licensing basis.

The NRC staff has reviewed the licensee's assessment of the GWMS according to the requirements of 10 CFR 20.1302; GDC-3, GDC-60, and GDC-61; and 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D. The NRC staff finds that the GWMS will continue to perform its design safety functions during EPU operations and the current design capability of the GWMS are capable of handling the effects of the EPU. Therefore, the NRC staff finds the licensee assessment of the GWMS acceptable for EPU operation.

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 EPU. The NRC staff further concludes that the licensee has demonstrated that the GWMS will continue to meet the requirements of 10 CFR 20.1302; GDC-3, GDC-60, and GDC-61; and 10 CFR Part 50, Appendix I, Sections II.B, II.C, and II.D. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the GWMS.

2.5.5.2 Liquid Waste Management Systems

Regulatory Evaluation

The NRC staff's review for liquid waste management systems (LWMS) focused on the effects that the proposed EPU 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 limiting conditions for operation to meet the ALARA criterion.

Technical Evaluation

The licensee used Section 8.1 of the CLTR to address the effect of proposed EPU on the LWMS. The licensee described in the LAR that the primary effect of EPU on the LWMS is a result of the increased load on the reactor water cleanup system and condensate demineralizers. The licensee stated that the increased condensate demineralizer loads are expected to increase the volume of liquid waste processed by the LWMS due to EPU by less than 10 percent, which will not impact the capacity of the LWMS. The licensee also evaluated the radiological effects of EPU on the LWMS, which is projected to be increased up to 20 percent relative to OLTP at NMP2. The licensee determined that the LWMS has sufficient margin between actual operation and design basis to withstand the 20 percent increase for EPU operation. The licensee concluded in its assessment of the LWMS that the current design and operation along with existing equipment and procedures for LWMS will be able to handle the effects of the proposed EPU in regards to controlling releases to the environment and remain within the guidelines of 10 CFR 20.1302; 10 CFR Part 50, Appendix I; and 40 CFR Part 190.

The NRC staff has reviewed the licensee's assessment of the LWMS according to requirements of 10 CFR 20.1302; GDC-60 and GDC-61; and 10 CFR Part 50, Appendix I, Sections II.A and II.D. The NRC staff finds that the LWMS will continue to perform its safety functions during EPU operation and that the system design is capable to withstand the effects of the EPU. The licensee's conclusion that existing equipment and procedures are unchanged to control releases using the LWMS appears adequate for EPU operation. Therefore, the NRC staff finds the licensee's assessment for the LWMS acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the LWMS. 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 LWMS to control releases of radioactive materials. The NRC staff finds that the LWMS will continue to meet their design functions following implementation of the proposed EPU. 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; GDC-60 and GDC-61; and 10 CFR Part 50, Appendix I, Sections II.A and II.D. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the LWMS.

2.5.5.3 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 EPU 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.

Technical Evaluation

The licensee used Section 8.1 of the CLTR to address the effect of proposed EPU on the SWMS. The licensee described in the LAR that the waste streams for the SWMS are (1) dry active waste; (2) spent ion exchange resin and filter sludge; and (3) evaporator concentrates. The licensee stated that the proposed EPU will not affect dry active waste, so the volume and mix of dry active waste is unchanged. The effect of EPU on the SWMS is primarily a result of the increased load on the reactor water cleanup system and condensate demineralizers. The increased demineralizer loads are expected to increase the volumes of spent ion exchange resin and filter sludge (the resin is no longer regenerated and the evaporators have been taken out-of-service, therefore there are no evaporator concentrates). The installed pre-filters are expected to reduce the total quantity of spent ion exchange resins. However, no credit is taken for the pre-filters at the present time.

The licensee projected that solid radwaste volume will increase approximately 7 percent under EPU operation. However, the licensee's evaluation concluded that the SWMS has sufficient design margin to handle the increase in solid radwaste. The licensee also stated that the proposed EPU will not generate a new type of waste or create a new waste stream. Additionally, the licensee evaluated the radiological effects of EPU operation at NMP2 and found that the operational radiological sources will increased by 20 percent relative to OLTP. However, the licensee concluded that the SWMS has sufficient design margin to accommodate the 20 percent increase. Radiation effluent limits and monitoring requirements are independent of RTP, and therefore are not affected by EPU operation.

The NRC staff reviewed the licensee's assessment of the SWMS for EPU operation according to 10 CFR 20.1302, GDC-60, GDC-63, and GDC-64, and 10 CFR Part 71. The NRC staff noted that no design modifications are being made to the SWMS and that the system should continue to perform its design function under EPU conditions and within the regulatory requirements. The NRC staff finds the licensee's assessment of the SWMS acceptable.

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 EPU. The NRC staff further concludes that the licensee has demonstrated that the SWMS will continue to meet the requirements of 10 CFR 20.1302, GDC-60, GDC-63, and GDC-64, and 10 CFR Part 71. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SWMS.

2.5.6 Additional Considerations

2.5.6.1 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 emergency diesel generator 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.

Technical Evaluation

The licensee evaluated emergency diesel engine fuel oil storage and transfer for EPU operation for emergency loads and mission time. The licensee stated that the existing system equipment is sufficient to handle the emergency loads and that the mission time will remain unchanged for EPU operation. In addition, the licensee indicated that no increase in flow or pressure is required of any AC-powered ECCS equipment for EPU operation and that the amount of power required to perform safety related functions (pump and valve loads) is not increased with EPU. The licensee concluded that the emergency diesel engine fuel oil storage and transfer system will continue to have sufficient capacity to support all required loads to achieve and maintain safe shutdown conditions and to operate the ECCS equipment following postulated accidents and transients.

The NRC staff has reviewed the licensee's assessment of the emergency diesel engine fuel oil storage and transfer system according to GDC-4, GDC-5, and GDC-17 and found that the system has the capability to perform its safety functions for EPU operation. No changes are being made to the emergency diesel engine fuel oil storage and transfer system and the regulatory requirements will continue to be met for EPU. Therefore, the NRC staff finds the licensee assessment of the emergency diesel engine fuel oil storage and transfer system acceptable.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the amount of required fuel oil for the emergency diesel generators and concludes that the licensee has adequately accounted for the effects of the 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 GDC-4, GDC-5, and GDC-17. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the fuel oil storage and transfer system.

2.5.6.2 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.

Technical Evaluation

The licensee used Section 6.8 of the CLTR to address the effect of the proposed EPU on NMP2 plant systems that are not significantly affected. The LLHS includes components and equipment used for handling new fuel at the receiving station and for loading spent fuel into shipping casks. The licensee indicated that the LLHS will not be changed for EPU operation and no new fuel designs are being introduced in conjunction with the proposed EPU. The licensee stated that the current design capability of the LLHS will continue to meet the required regulations for radioactivity releases and prevention of criticality accidents for EPU operation. The NRC staff has reviewed the licensee's assessment according to GDC-61 and GDC-62 and finds the licensee's conclusion acceptable since no changes are being made to the LLHS and the system was assessed to have the design capability to continue to perform its safety function under EPU conditions.

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 GDC-61 and GDC-62 for radioactivity releases and prevention of criticality accidents. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the LLHS.

2.5.6.3 Power Ascension and Testing Plan

Regulatory Evaluation

The NRC staff reviewed the licensee's power ascension and testing plan as it relates to BOP systems included within the scope of the original NMP2 pre-operational test program or subject to extensive modification to support operation at the EPU power level. With regard to BOP systems, the original pre-operational test program included performance tests for the CFS system and the turbine bypass system, as well as integrated plant testing (e.g., generator load rejection and turbine trip tests). Licensees commonly modify BOP systems, especially the CFS system, to support operation at the EPU power level. The licensee evaluated the NMP2 EPU test plan in accordance to NUREG-0800, "Standard Review Plan (SRP) for the Review of Safety Analysis Reports for Nuclear Power Plants: Light Water Reactor Edition" Section 14.2.1, for justification for performing or excluding large transient testing for EPU operation.

Technical Evaluation

The turbine bypass control system is designed to control reactor pressure when the main turbine is unavailable by discharging steam to the main condenser. The licensee did not propose to credit additional steam bypass capacity beyond what was previously assumed, and no modifications are being made to the steam bypass system for EPU operation. Therefore, transient testing for the purpose of demonstrating acceptable performance of the turbine bypass control system is not required.

The CFS provides feedwater to the reactor vessel during normal operation and following certain anticipated operational occurrences, such as a turbine trip or a main generator load rejection. The feedwater system controls the rate of feedwater flow to maintain an appropriate water level in the reactor vessel during these conditions. The feedwater pumps automatically trip on high water level to reduce the potential for main steam-line flooding; and interlocks prevent operation of a feedwater pump when pump suction pressure is low, bearing oil pressure is low, the pump recirculation valve is not open, or the fire disconnect switch is in the actuated position. Sustained low-suction pressure or low-low suction pressure will stop a running pump. The modifications to the condensate and reactor feedwater systems proposed by the licensee for EPU implementation include the replacement of feedwater pump impellers, motor power cables and speed increasers. The heater drain pump internals and motors will also be replaced. The licensee stated that the individual changes to the CFS will be addressed during post modification testing and the aggregate impact will be addressed by feedwater system power ascension testing.

In Attachment 7 to the LAR, "EPU Test Plan," the licensee described the proposed EPU power ascension testing that is partially consistent with the NMP2 pre-operational test program. The licensee proposed to exclude from the EPU power ascension test program the feedwater pump trip and the main turbine trip tests, which were part of the NMP2 pre-operational test program. Although the purpose of the feedwater pump pre-operational trip test was to evaluate the reactor response to changes in sub-cooling of water in the reactor, the test also provided information regarding the transient response of the feedwater system.

The licensee will increase EPU power in pre-determined increments of ≤ 5 percent power starting at 90 percent CLTP RTP so that system parameters can be projected for EPU power before the CLTP RTP is exceeded. Operating data, including fuel thermal margin, will be taken and evaluated at each step. Routine measurements of reactor and system pressures, flows and vibration will be evaluated by the licensee for each measurement point, prior to the next power increment. Radiation measurements will be made at selected power levels to ensure the protection of personnel. Control system tests will be performed for the reactor feedwater/reactor level controls and pressure controls. These operational tests will be made at the appropriate plant conditions for that test at each of the power increments, to show acceptable adjustments and operational capability.

The licensee provided justification for the exclusion of the large transient tests from the EPU test program in Section 5.0 of Enclosure 7 to the LAR. The licensee referenced SRP 14.2.1, Section III.C.2 to justify the exclusion of the large transient testing involving the feedwater pump trip and main turbine trip. The licensee compared the startup tests, the actual NMP2 operating experience associated with the trips, and analysis under EPU conditions to provide its justification.

The objective of the feedwater pump trip test at plant startup was to demonstrate the capability of the automatic core flow runback feature to prevent a low water level scram following the trip of one feedwater pump. The feedwater pump was tripped with reactor power at 99 percent of the OLTP. The feedwater control system maintained a margin of 12.7 inches to level 3, well above the level 2 acceptance criteria of greater than a 3-inch margin. The recirculation runback feature was actuated 7 seconds into the transient as level dropped below level 4 (approximately 5 inches below normal level). The recirculation flow control valves closed from 82 percent to 15 percent, which reduced reactor power to 60 percent of the OLTP, and stayed within the capacity of the remaining feedwater pump. The test satisfied all acceptance criteria. The licensee cited sufficient operating experience involving a trip of the feedwater pumps, each one occurring once in 1995, 2001, and 2004 respectively, all above 80 percent of the OTLP, due to electrical motor fault. In two cases, the reactor scram was avoided at low level whereas the third case, the reactor was manually scrammed to avoid the low level trip. For EPU operation, the licensee plans to implement the following modifications in order to minimize the possibility of a low level scram upon loss of a single feedwater pump:

- Initiation of a recirculation flow control valve runback immediately upon a feedwater pump trip. Current logic requires level to reach the Level 4 setpoint before a runback is initiated.
- Increasing the recirculation flow control valve runback rate from the current 6-8 percent per second to 9 percent per second.

The licensee performed analysis of avoidance of a single feedwater trip at EPU conditions at low level and determined the above modifications would be needed to maintain the existing margin for scram avoidance.

The objective of the turbine trip and generator load rejection test was to: 1) demonstrate the response of the reactor and its control systems to protective trips in the turbine and generator and 2) demonstrate the capacity of the turbine bypass valves. The generator load rejection was performed with the reactor operating at 99.6 percent of rated power by simulating a 345 KV line high differential voltage/current fault. The turbine-generator power load unbalance (PLU) logic sensed the load reject and initiated fast control valve closure. The bypass valve control system actuated to rapidly open the bypass valves. The simulated electrical fault also initiated a turbine trip which caused fast turbine stop valve closure. A reactor scram was initiated by the control valve fast closure and the recirculation pumps transferred to the low frequency motor generator as designed. The licensee cited NMP2 operating experience involving the turbine trip and generator load rejection, which occurred once in 1994, 1999, and 2003, all due to the turbine control valve fast closure signal causing the scram. All three events occurred between 100 percent and 104 percent of the OTLP and were bounded by the generator load rejection with bypass transient for NMP2. The licensee evaluated the effect of the EPU operation relating to the turbine trip and generator load rejection and found that based on past transient testing, past analyses and the evaluation of test or actual event results, the effects of a trip from EPU RTP can be analytically determined and no further testing would be needed.

Conclusion

The NRC staff has determined that past plant experience combined with a demonstration of acceptable plant performance during the proposed EPU power ascension test program is sufficient to demonstrate that BOP systems will function as designed under EPU conditions. The NRC staff reviewed the licensee's justification for not performing large transient testing for the feedwater pump and turbine trips as discussed in Attachment 7 to the LAR. The NRC staff found the licensee's justification of excluding of the feedwater and main turbine trip tests from the EPU test program to be acceptable based on the applicable review criteria discussed in Section III.C.2 of SRP 14.2.1.

Section 2.12 of this SE presents the NRC staff's remaining technical evaluation for the licensee's power ascension and testing plan.

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 NRC staff's review for the primary containment functional design covered:

(1) The temperature and pressure conditions in the drywell and wetwell due to a spectrum of postulated loss-of-coolant accidents (LOCAs),

(2) The differential pressure across the operating deck for a spectrum of LOCAs (Mark II containments only),

(3) Suppression pool dynamic effects during a LOCA or following the actuation of one or more RCS safety/relief valves,

(4) The consequences of a LOCA occurring within the containment (wetwell),

(5) The capability of the containment to withstand the effects of steam bypassing the suppression pool,

(6) The suppression pool temperature limit during RCS safety/relief valve operation, and

(7) The analytical models used for containment analysis.

The NRC's acceptance criteria for the primary containment functional design 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-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;

(3) GDC-50, insofar as it requires that the containment and its associated heat removal systems be designed so that the containment structure can accommodate, without exceeding the design leakage rate and with sufficient margin, the calculated temperature and pressure conditions resulting from any LOCA;

(4) GDC-13, insofar as it requires that instrumentation be provided to monitor variables and systems over their anticipated ranges for normal operation and for accident conditions, as appropriate, to assure adequate safety;

(5) GDC-64, insofar as it requires that means be provided to monitor the reactor containment atmosphere for radioactivity that may be released from normal operations and from postulated accidents. Specific review criteria are contained in SRP Section 6.2.1.1.C., and

(6) RS-001, Revision 0, NRC Office of Nuclear Reactor Regulation Review Standards For Extended Power Uprates.

Technical Evaluation

The primary containment structure of NMP2 consists of the drywell, the pressure suppression chamber that stores a large volume of water, and the drywell floor, which separates the drywell and suppression chamber. The drywell is a steel lined, reinforced concrete, vessel in the shape of a frustum of a cone, closed by a dome with a torispherical head. The pressure suppression chamber is a cylindrical stainless-steel clad, steel lined, reinforced concrete, vessel located below the drywell. The primary containment structure houses the reactor vessel, the reactor recirculation system, and other branch connections of the RCPB.

The primary containment design features include the drywell, the pressure suppression chamber, downcomers between the drywell and the suppression chamber, isolation valves, vacuum breakers, and the RHR system for containment heat removal. The primary containment is a steel-lined, reinforced concrete pressure vessel that is closed at the top by the drywell head assembly. The steel drywell head assembly forms a gas-tight enclosure.

The proposal to operate at EPU conditions requires that safety analyses for those design-basis accidents whose results depend on power level be recalculated at the higher power level. The containment design basis is primarily established based on the LOCA and the actuation of the reactor vessel safety relief valves and their discharge into the suppression pool. The short-term analysis is directed primarily at determining the drywell pressure response during the initial blowdown of the reactor vessel inventory to the containment following a large break of a recirculation line inside the drywell. The long-term analysis is directed primarily at the suppression pool temperature response, considering the decay heat addition to the suppression pool. The effect of power on the events yielding the limiting containment pressure and temperature responses are provided below.

NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," Class III, July 2003 (also referred to as CLTR) was approved by the NRC as an acceptable method for evaluating the effects of Constant Pressure Power Uprates (ML032170343 proprietary version, ML032170332 non-proprietary version). Section 4.1 of the CLTR addresses the effect of Constant Pressure Power Uprate on Primary Containment Functional Design. The containment evaluation in NEDC-33351 is based on NEDC-33004P-A and NEDC-32424-A, "Generic Guidelines for General Electric Boiling Water Extended Power Uprate (ML036802315 proprietary version). The GE computer code M3CPT was used to perform short-term containment pressure and temperature response analyses. The GE computer code SHEX was used in the analysis to model long-term containment temperature and pressure response. These codes, M3CPT and SHEX, have been used for other NRC-approved extended power uprate license amendments.

The NMP2 USAR provides the containment responses to various postulated accidents that validate the design basis for the containment. EPU operation changes some of the conditions for the containment analyses. For example, the short-term DBLOCA containment response during the blowdown is governed by the blowdown flow rate. This blowdown flow rate is dependent on the reactor initial thermal-hydraulic conditions, such as vessel pressure and the mass and energy of the vessel fluid inventory, which change slightly with EPU. In addition, the long-term heat-up of the suppression pool following a LOCA or a transient is governed by the ability of the residual heat removal (RHR) system to remove decay heat. Because the decay heat depends on the initial reactor power level, the long-term containment response is affected by EPU. NEDC-33351 reanalyzed the containment response to demonstrate the plant's capability to operate with a rated power increase to 3988 MWt. NEDC-33351, Table 2.6-2 provides the key plant parameters used to model and analyze the plant response at EPU.

The re-evaluation of the short-term and long-term containment LOCA response is done with several changes to the Nine Mile Point licensing basis. These changes are: (1) initiation of containment spray at 20 minutes instead of the current initiation time of 30 minutes; (2) use more realistic RHR heat exchanger performance values to limit predicted suppression pool temperatures; and (3) the use of ANSI/ANS 5.1-1979 decay heat model, with a 2σ uncertainty instead of the ANS 5 model with a 20 percent/10 percent uncertainty. These changes are consistent with GE containment analyses accepted by the NRC for other BWR licensing actions. Therefore, the NRC staff finds these changes are acceptable for NMP2.

The short-term analysis determines the containment pressure response during the initial blowdown of the reactor vessel inventory to the containment following a large break inside the drywell. The licensee stated that the initial drywell pressure excursion during blowdown may not produce the most limiting containment pressure conditions. The NMP2 containment design has a vent area to break area ratio that is at least 20% larger than other Mark II plants which tends to reduce the first peak. The NMP2 is also among the Mark II plants with a relatively large drywell to wetwell volume ratio that increases the second peak due to increased transfer of non-condensable gas from drywell to wetwell. Therefore, the licensee examined the potential for the drywell pressure to exceed the early pressure spike at some time later in the transient by extending the short-term analysis to over 250 seconds of transient time.

The short-term analysis covers the blowdown period during which the maximum drywell pressure, maximum wetwell pressure, and maximum differential pressure between the drywell and wetwell occur. The short-term DBA LOCA analysis assumes a double-ended guillotine break of a reactor coolant recirculation pump suction line. The NMP2 USAR DBA postulated for the current licensing thermal power calculation of the maximum pressure acting on the drywell walls is a double-ended rupture (DER) of a 24-inch recirculation suction line. This event is more severe than a DER of the 26-in main steam line. The licensee determined that the recirculation suction line break remains the limiting event. Steam flow from a double-ended guillotine break of the main steam line will be limited by choked flow. The critical pressure ratio at choked flow is roughly 0.54. Since this is a constant pressure power uprate, the analysis from the original main steam line break remains unchanged due to choked flow.

The short-term containment analyses were based on several conservative assumptions. The reactor is assumed to be operating at two percent above the rated thermal power to include instrument uncertainty effects, consistent with NUREG-0800, Standard Review Plan 6.2.1.3, "Mass and Energy Release Analysis for Postulated Loss-Of-Coolant Accidents (LOCAs)." The suppression pool level and mass are at values corresponding to the maximum technical specifications limit. The analysis assumes the recirculation suction line instantaneously undergoes a double guillotine break. The short-term DBLOCA containment response during the blowdown is governed by the blowdown flow rate. This blowdown flow rate is dependent on the reactor initial thermal-hydraulic conditions, such as vessel pressure and the mass and energy of the vessel fluid inventory, which change slightly with the EPU. NEDC-32424 (approved by the NRC in SE dated September 14, 1998 (ADAMS Accession No. ML003680219)) details the methodology for the analysis.

In a letter dated October 8, 2010, the licensee informed the NRC staff that the peak containment pressure analysis which formed the basis for the EPU LAR dated May 27, 2009 is impacted by a GE Hitachi (GEH) Safety Communication (SC) 09-05. The issue is related to the M3CPT code used in the short-term analysis of the DBA-LOCA. The licensee stated that the M3CPT simulation of the containment response did not model gravity induced settling of break fluid in the drywell airspace. The licensee further stated that based on the explanation provided in GEH SC09-05, the M3CPT prediction during the early DBA-LOCA blowdown period is conservative as it results in higher drywell pressure due to the presence of liquid in the vent flow. However, the M3CPT modeling can produce a holdup of a significant quantity of warm break fluid in the drywell atmosphere near the end of the blowdown period when the calculated vent flow is small or intermittent. The holdup of the break fluid in the drywell can under predict the DBA-LOCA peak drywell pressure if the calculated peak drywell pressure occurs near the end of the blowdown period. The letter dated October 8, 2010 provided the results of a reanalysis of the drywell peak pressure that occurs near the end of blowdown.

The licensee evaluated the impact of GEH SC09-05 on the maximum drywell pressure with the GOTHIC code (Version 7.2b). The modeling capability of GOTHIC includes gravity induced settling of droplets. The NRC staff has previously approved the application of GOTHIC to model peak containment pressure at other plants. The licensee stated that the M3CPT code continues to be utilized to provide the mass and energy input to the GOTHIC code and the GOTHIC code is utilized to determine the peak containment pressure for the second peak. The licensee further informed the NRC staff that the M3CPT code continues to be utilized to determine the initial containment pressure peak, peak drywell-to-wetwell differential pressure, and the hydrodynamic loads. The peak drywell to wetwell pressure differential is 18.6 psi as provided in Table 2.6-1 of NEDC-33351. The licensee stated that the drywell design temperature is 340 °F and it was determined based on a bounding analysis of the superheated gas temperature which can be caused by a blowdown of steam to the drywell during a small break LOCA. This analysis conservatively determined a bounding combination of vessel pressure and drywell pressure that produces a maximum calculated drywell temperature. Based on the NMP2 USAR, the expansion of reactor steam under these conditions will result in a calculated peak drywell temperature of 325.8°F. The licensee stated that the bounding conditions are independent of the initial reactor power and therefore, the EPU will have no effect on the drywell temperature.

The GOTHIC analysis for the second peak during a DBA LOCA short-term was performed for several combinations of initial drywell temperature, drywell relative humidity, and wetwell temperature. The case reflective of the lower bound normal operating drywell temperature of 105 °F and relative humidity of 40%, together with normal operating maximum suppression pool temperature of 90 °F was used to show that the peak calculated containment pressure is lower than the Technical Specifications P_a value of 39.75 psig. The calculated containment pressure is 39.5 psig. The normal operating temperature is established by a statistical analysis of the plant operating data and applying mean and standard deviation to this data. The case reflective of the USAR lower bound conditions of drywell temperature of 70 °F and relative humidity of 20% together with a suppression pool temperature of 90 °F was used to show that the calculated peak drywell pressure would not exceed the containment design limit of 45 psig. The calculated peak pressure for this case is 42.08 psig.

Long-Term LOCA Analysis

The long-term LOCA analysis was performed for the DBA LOCA at two percent above the extended power uprate rated thermal power. The analysis of the peak suppression pool temperature, long-term peak wetwell pressure and peak wetwell air temperature used the SHEX computer code. The NRC has accepted this computer code for previous power uprate applications. Table 2.6-1 of NEDC-33351 provides the results of these analyses at extended power uprate and the acceptance criteria. The results indicate that under EPU conditions, the peak wetwell pool temperature during a DBA-LOCA is 207 °F.

Conclusion

The NRC staff has reviewed the licensee's assessment of the containment temperature and pressure transient and concludes that the licensee has adequately accounted for the increase of mass and energy resulting from the proposed EPU. 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 containment systems and instrumentation will continue to be adequate for monitoring containment parameters and release of radioactivity during normal and accident conditions and the containment and associated systems will continue to meet the requirements of GDCs 4, 13, 16, 50, and 64 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to primary containment functional design.

2.6.2 Subcompartment Analyses

Regulatory Evaluation

A sub-compartment 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 sub-compartment analyses covered the determination of the design differential pressure values for containment sub-compartments. The NRC staff's review focused on the effects of the increase in mass and energy release into the containment due to operation at EPU conditions, and the resulting increase in pressurization. The NRC's acceptance criteria for sub-compartment 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 sub-compartments be designed with sufficient margin to prevent fracture of the structure due to the calculated pressure differential conditions across the walls of the sub-compartments. Specific review criteria are contained in SRP Section 6.2.1.2.

Technical Evaluation

NMPNS reviewed the pressure loading on the drywell head refueling bulkhead plate due to a postulated break in the reactor core isolation cooling (RCIC) head spray line in the drywell head sub-compartment. They stated that because the steam dome pressure is unchanged the fluid enthalpy is essentially the same as the current licensed thermal power. Therefore, the mass and energy release from the break and the consequent upward pressure on the bulkhead are not significantly affected.

The critical pressure ratio for steam is roughly 0.54. At normal operating pressure, any break in the RCIC will have its steam flow from the reactor restricted or "choked." The EPU will not increase the choked flow. The drywall head refueling bulkhead plate loads remain within the allowable limits.

Conclusion

The NRC staff has reviewed the sub-compartment assessment performed by the licensee and the change in predicted pressurization resulting from the increased mass and energy 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 sub-compartments will continue to have sufficient margins to prevent fracture of the structure due to pressure difference across the walls following implementation of the proposed EPU. Based on this, the NRC staff concludes that the plant will continue to meet GDCs 4 and 50 for the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to sub-compartment analyses.

2.6.3 Mass and Energy Release

2.6.3.1 Mass and Energy Release Analysis for Postulated Loss-of-Coolant Accident

Regulatory Evaluation

The release of high-energy fluid into containment from pipe breaks could challenge the structural integrity of the containment, including sub-compartments and systems within the containment. The NRC staff's review covered the energy sources that are available for release to the containment and the mass and energy release rate calculations for the initial blowdown phase of the accident. The NRC's acceptance criteria for mass and energy release analyses for postulated LOCAs are based on: (1) GDC-50, insofar as it requires that sufficient conservatism be provided in the mass and energy 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 USAR drywell design temperature of 340 °F was determined based on a superheated gas temperature from a postulated blowdown of steam to the drywell during a small-break LOCA. NMPNS indicates the drywell temperature for a small-break LOCA is calculated independent of reactor power level. Therefore, the EPU will have no impact on the peak drywell temperature. The short-term containment pressure response for the limiting design basis LOCA assumes a double-ended guillotine break of a recirculation suction line. The analysis was performed at 102 percent of the EPU reactor thermal power level. The results of this analysis are discussed in Section 2.6.1.

Conclusion

The NRC staff has reviewed the licensee's mass and energy release assessment and concludes that the licensee has adequately addressed the effects of the proposed EPU 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 mass and energy release analysis meets the requirements in GDC-50 for ensuring that the analysis is conservative. Therefore, the NRC staff finds the proposed EPU acceptable with respect to mass and energy release for postulated LOCA.

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 EPU 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; (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 post-LOCA production of hydrogen and oxygen by radiolysis increases proportionally with the power level. The Combustible Gas Control System (CGCS) is designed to maintain the post-LOCA concentration of oxygen or hydrogen in the containment atmosphere below the lower flammability limit. The primary containment nitrogen inerting system establishes and maintains an oxygen-deficient atmosphere in the primary containment during normal operation. The long-term control of hydrogen and oxygen is achieved by means of two identical 150-scfm thermal hydrogen recombiners, located in the reactor building and controlled from the main control room. The recombiner system removes gas from the drywell or suppression chamber, recombines the hydrogen with oxygen, and returns the gas mixture along with the condensate to the suppression chamber.

Although the licensee's EPU evaluation of the CGCS is in accordance with RG 1.7, several evaluation parameters differ from the current licensed thermal power (CLTP) analysis. These changes included initial drywell and wetwell temperatures and humidity, a shorter recombiner warmup time (1.5 hours instead of 6 hours), lower recombiner initiation limits (3.4 percent H_2 and 3.6 percent O_2 instead of 4 percent H_2 and 4.5 percent O_2), a change in fuel design, and a smaller fuel cladding mass for the determination of hydrogen produced by the metal-water reaction. As a result, the operator action time for starting the drywell recombiner for the EPU evaluation (32.6 hours) is less than the time determined in the CLTP evaluation (43.5 hours). The operator action time for EPU, however, is considered sufficient for the operator to react to the appropriate indications (rising hydrogen/oxygen levels) and start the recombiners to assure that hydrogen is maintained below the flammability limit. Therefore, the CGCS system would continue to meet its design function post-LOCA after EPU implementation.

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 and GDCs 5, 41, 42, and 43 as discussed above. Therefore, the NRC staff finds the proposed EPU acceptable with respect to combustible gas control in containment.

2.6.5 Containment Heat Removal

Regulatory Evaluation

Fan cooler systems, high-pressure core spray (HPCS) and low-pressure core spray (LPCS) systems, and residual heat removal (RHR) systems are provided for core injection and to remove heat from the containment atmosphere and from the water in the containment wetwell. The NRC staff's review in this area focused on (1) the effects of the proposed EPU on the analyses of the available net positive suction head (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 a containment heat removal system be provided, and that its function shall be to rapidly reduce the containment pressure and temperature following a LOCA and maintain them at acceptably low levels. Specific review criteria are contained in SRP Section 6.2.2, as supplemented by RG 1.82, Revision 3. The NMP2 USAR references RG 1.1, insofar that it prohibits the reliance on pressure transients expected during a LOCA for assuring adequate NPSH to the ECCS pumps. The licensee stated that neither the current licensing basis nor the proposed EPU would rely on containment accident pressure (CAP) to assure adequate NPSH to the ECCS pumps. The NRC staff's review in two specific areas, uncertainties in NPSH required (NPSHR) and operation in the maximum erosion zone, is based on the guidance provided by the NRC staff in a letter dated March 1, 2010 (ADAMS Package Accession No. ML100740579), to the Boiling Water Reactor Owners' Group (BWROG).

Technical Evaluation

Fan cooler systems, spray systems, and residual heat removal (RHR) systems are installed to remove heat from the containment atmosphere and from the water in the containment wetwell. The NMPNS review in this area focused on the effects of the proposed EPU on the analyses of the available net positive suction head (NPSH) to the containment heat removal system pumps and the analyses of the heat removal capabilities of the RHR heat exchangers. These systems are installed to meet the requirements for 10 CFR Part 50, Appendix A, GDC-38, "Containment heat removal."

The fan cooler systems operate for normal plant operational modes. It is required to maintain the containment ambient temperature below that temperature assumed in the accident analysis. The long-term containment accident analyses, directed primarily at the suppression pool temperature response, assumed the maximum allowable average drywell temperature per TS 3.6.1.5 of 150 °F initial drywell temperature.

The peak containment pressure is defined by the short-term response where the maximum pressure is defined by a lower drywell initial condition temperature assumption. The original USAR licensing basis analysis that established the peak calculated accident pressure (Pa = 39.75 psig) assumed a nominal drywell temperature of 135 °F. The current typical 100 percent power drywell average temperature is approximately 110 °F and the evaluation of the impact of EPU on the operating temperature is calculated to be less than a 1 °F increase. Therefore, the small increase in normal operating temperature has no impact on the peak containment analysis pressure (based on 150 °F initial drywell temperature).

The containment spray system is capable of quickly reducing containment pressure during the post-accident period of a LOCA through condensation of steam in the drywell and through cooling of the non-condensable gases in the free volume above the suppression pool. The containment spray system is designed for a peak primary containment pressure not to exceed the containment design pressure of 45 psig, and the peak suppression pool water temperature does not exceed the design suppression pool water temperature of 212 °F.

NEDC-33351, Table 2.6-1 shows the peak containment pressure with EPU will remain below the design pressure of 45 psig (59.7 psia). The containment spray system operating with EPU remains within the original design limits.

Table 2.6-3 of NEDC-33351 provides RHR heat exchanger performance values used in the EPU analyses. These values (K-value of 265 BTU/sec- °F for EPU DBLOCA) are higher than the actual heat exchanger performance with service water at 82 °F (K-factor of 239 BTU/sec- °F as discussed in NMP2 USAR, Section 6.2). The NRC staff requested clarification on the value used in the calculation and the actual performance as listed in the USAR. The NRC staff also requested clarification on the discrepancy between the RHR heat exchanger total fouling resistance used for the EPU analysis (0.001433 hr-ft²-°F/BTU/HX for DBLOCA) and the NMP2 USAR (0.001 hr-°F-ft²/BTU for tube side fouling plus 0.0005 hr-°F-ft²/BTU for shell side fouling).

NMPNS provided a response on April 16, 2010 (ML101120658), responding to the NRC staff' RAI. For RAI-12-F, the licensee stated that the USAR discussion is based on the original design specified RHR heat exchanger performance that was conservatively defined based on an assumed decreased performance of the RHR heat exchanger capability. The actual performance of the RHR heat exchanger based on clean design is equivalent to a K=384. The actual tested RHR K value is measured at a K of ~ 363, which is higher than the K value used in the EPU analyses. Periodic testing (4-year interval), inspection/cleaning provide assurance that required performance is met and that margin is maintained between the EPU safety analyses assumed performance and the actual measured performance.

NEDC-33351 determined the suppression pool bulk temperature with EPU will be less than 212 °F. In response to the NRC staff's request, NMPNS in a letter dated May 9, 2011, provided the results of supplementary NPSH evaluations performed at the proposed EPU conditions. The evaluations were performed for various scenarios including DBA LOCA, Alternate Shutdown Cooling (ASDC), Appendix R Fire, and Anticipated Transient Without Scram (ATWS). The evaluations were based on $NPSHR_{3\ percent}$ values extracted from the pump vendor curves, maximum suppression pool temperatures reached in each case, and minimum suppression pool levels. The uncertainties in NPSHR included in the NRC staff guidance address the possibility that conditions during the NPSHR vendor tests could be different from what may be encountered by the pumps during operation, effectively increasing the NPSHR values. The differences could arise due to pump inlet temperature variation, pump inlet geometry variation, dissolved gas evolution, mechanical wear ring clearance, etc. Based on an NRC pump consultant's report on uncertainties, an average variation in the NPSHR of between +9 percent to +21 percent could be expected depending on the differences in installation and operation between the NPSHR test and plant conditions. The NRC staff conservatively elected to use a 21 percent margin on the $NPSHR_{3\%}$ as a bounding estimate in this review, denoted as NPSHR effective ($NPSHR_{eff}$), and advised NMPNS that it may use this value in-lieu of plant-specific evaluations or testing to determine the uncertainty. NMPNS opted to use the 21 percent uncertainty on NPSHR in their NPSH evaluations. The evaluations show that NMP2 does not need to credit containment pressure during an event to assure adequate ECCS pump NPSH, even when uncertainty in NPSHR is considered. The NRC staff's guidance states that the zone of maximum erosion should be assumed to lie between NPSH margin ratios of 1.2 to 1.6 and recommends no more than 100 hours of operation in the maximum erosion zone. The results of the licensee's evaluations indicate that the NPSH available (NPSHA) to the ECCS pumps is always greater than $NPSH_{eff}$ for all cases. In addition, the NPSH margin ratio is always greater than 1.6 for all cases when using $NPSH_{3\ percent}$ values. The NPSH margin ratio is also greater than 1.6 for all cases except for LPCI operation, when using $NPSHR_{eff}$ values. The evaluation shows that the LPCI pumps may operate at a NPSH margin ratio of less than 1.6 for approximately 14 hours during DBA LOCA and 6.3 hours for ASDC, well below the 100 hours limit.

By letter dated May 19, 2011, NMPNS stated that Station Blackout (SBO) scenario was not included in the NPSH evaluations as the reactor core Isolation cooling (RCIC) pump, which is relied on during the coping period, takes suction from the condensate storage tank thus assuring adequate NPSH. In response to NRC staff's RAI, NMPNS in a letter dated August 19, 2011, provided an evaluation to address the operation of the RHR pump after the coping period of 4 hours. The licensee's evaluation is based on conservative assumptions of a single loop of RHR in suppression pool cooling and reduced containment spray mode flow rate after the coping period. The assumptions result in continued suppression pool heat-up until shutdown cooling (SDC) is initiated when the reactor pressure is reduced to below the SDC interlock. Reactor depressurization during this restoration period is achieved with one safety relief valve (SRV) remaining open to the suppression pool. The evaluation shows that the suppression pool temperature remained below 212 °F during the restoration period, prior to the initiation of SDC. By taking credit for an additional 2 feet of head in suppression pool resulting from the RCIC operation during the coping period and no debris loading on the strainers, the licensee was able to show that a NPSH margin ratio of 1.6 is maintained, assuming no containment accident pressure. The licensee's evaluation is based on reasonable assumptions, and therefore is acceptable to the NRC staff.

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 EPU. The NRC staff finds that the systems will continue to meet GDC-38 with respect to rapidly reducing the containment pressure and temperature following a LOCA and by maintaining them at acceptably low levels. The NRC staff also finds the proposed license amendment meets the guidance of Regulatory Guide 1.1, "Net Positive suction Head for Emergency Core Cooling and Containment Heat Removal System Pumps." The NRC staff also concludes that NMP2 does not credit containment accident pressure to assure adequate NPSH to the ECCS pumps and that it also meets the NRC staff's guidance on NPSH uncertainty and operation in maximum erosion zone. Therefore, the NRC staff finds the proposed EPU acceptable with respect to ECCS and containment heat removal systems.

2.7 Habitability, Filtration, and Ventilation

2.7.1 Control Room Habitability System

Regulatory Evaluation

The NRC staff reviewed the control room 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 control room 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 EPU on radiation doses, toxic gas concentrations, and estimates of dispersion of airborne contamination. The NRC's acceptance criteria for the control room 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 control room 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

Control room habitability was reviewed as part of the licensee's May 31,2007, license amendment request (ML071580314) to adopt the alternate source term (AST) in accordance with 10 CFR 50.67. The AST amendment request was based on analyses performed at an assumed reactor thermal power of 3988 MWth +2 percent (4067 MWth).

For the design-basis alternate source-term LOCA analysis, the licensee assumed that the core isotopic inventory available for release into the containment, is based on maximum full power operation of the core at 4,067MWth (1.02 times a 15 percent uprate of the current licensed thermal power level of 3,467 MWth, in order to account for the ECCS evaluation uncertainty). Additionally, the burnup and enrichment parameters assumed when determining the core isotopic inventory are within current licensed limits for fuel at NMP2. The licensee assumed a 24-month cycle at 1400 effective full-power days (EFPD) per cycle and a 4.1 percent average enrichment.

For their revised analyses where control room isolation and/or filtration is credited, the licensee assumed an emergency mode control room intake flow rate of 2500 cfm ±10 percent, and assumed 99 percent filtration efficiency for elemental iodine, organic iodine, and particulate forms of radionuclide activity. For conservatism, the upper flow uncertainty value, 2750 cfm, is used for modeling, then, as a design basis, reduced to 1650 cfm at 20 minutes. Where control room filtration is credited, the licensee assumed that the control room was automatically isolated on a LOCA signal, and that filtration was delayed for 80 seconds. In a letter dated January 31, 2005, from the licensee to the NRC staff (ML050460309), it is indicated that the highest measured unfiltered inleakage into the NMP2 control room is 174 cfm.

For the DBA analyses that model actual NMP2 control room functionality, the licensee assumed an unfiltered inleakage of 250 cfm, to bound the worst-case unfiltered inleakage as tested. This value is conservative and provides margin for future measurements of control room inleakage.

On May 29, 2008, the NRC issued Amendment No. 125 to Renewed Facility Operating License No. NPF-69 for the NMP2 (ML081230439). This amendment changed the NMP2 TSs by revising the accident source term in the design basis radiological consequence analyses in accordance with 10 CFR Section 50.67.

Conclusion

The NRC staff has reviewed the licensee's assessment related to the effects of the proposed EPU on the ability of the control room 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 EPU. The NRC staff further concludes that the control room habitability system will continue to provide the required protection following implementation of the proposed EPU. Based on this, the NRC staff concludes that the control room habitability system will continue to meet the requirements of GDCs 4 and 19. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the control room habitability system.

2.7.2 Engineered Safety Feature Atmosphere Cleanup

Regulatory Evaluation

Engineered safety feature (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., standby gas treatment systems and emergency or post-accident air-cleaning systems) for the fuel-handling building, control room, 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 EPU 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 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 control room 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 be provided for monitoring effluent discharge paths and the plant environs for radioactivity that may be released from normal operations, including anticipated operational occurrences (AOOs), and postulated accidents. Specific review criteria are contained in SRP Section 6.5.1.

Technical Evaluation

The ESF atmosphere cleanup system at NMP2 is the Standby Gas Treatment System (SGTS). The SGTS maintains the secondary containment at a negative pressure during abnormal conditions. SGTS consists of fans, filters, and associated components. The SGTS filter assembly consists of moisture separator, heating coil, pre-filter, high efficiency particulate air (HEPA) filter, carbon adsorber, and HEPA filter.

The EPU has a slightly larger iodine inventory in the reactor core. NMPNS reviewed the increase in iodine loading on the carbon adsorber and any increase in temperature resulting from radiological decay of the adsorbed iodine. The total adsorbed iodine will remain below the Regulatory Guide 1.52 limit of 2.5 mg of total iodine (radioactive plus stable) per gram of activated carbon. They also verified that [[

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For the design-basis alternate source term LOCA analysis, the licensee assumed that the core isotopic inventory available for release into the containment, is based on maximum full power operation of the core at 4,067 megawatts thermal (MWth) (1.02 times a 15 percent uprate of the current licensed thermal power level of 3,467 MWth, in order to account for the ECCS evaluation uncertainty). Additionally, the burnup and enrichment parameters assumed when determining the core isotopic inventory are within current licensed limits for fuel at NMP2. The licensee assumed a 24-month cycle at 1400 effective full-power days (EFPD) per cycle and a 4.1 percent average enrichment.

The current amendment request does not significantly alter any of the parameters credited in the Safety Analysis for Amendment No. 125 to the renewed operating license number NPF-69. As indicated in Section of the staff's safety evaluation for the AST license amendment:

> By crediting the NMP2 Standby Liquid Control (SLC) System capability to introduce sodium pentaborate to act as a buffer into the reactor coolant, the licensee has determined that the suppression pool pH remains above 7.0 for the duration of the accident. Therefore, in analyzing activity transport from containment, it was unnecessary for the licensee to consider re-evolution of iodine dissolved in the coolant.

The NRC staff notes that this statement remains valid for EPU conditions, and the associated evaluation determined that the SLC system remains capable of pH control for the accident [20] duration.

Regarding the analysis of the post-LOCA suppression pool pH, the licensee's EPU evaluation determined that the effect of EPU was small. In the unbuffered case, the calculated time for pool pH to drop below 7.0 changed from about 12 days to 10 days due to the EPU. Therefore, the conclusion that the 4.4 hour time required to reach mixing equilibrium for (1) the water in the vessel, (2) the drywell floor pool, and (3) the suppression pool remains unchanged (i.e., the required time to reach mixing equilibrium of 4.4 hours is significantly less than the 10 days). The licensee's evaluation also determined that there was essentially no change to the final pool pH at 30 days, which changed from 8.3 to 8.26 days for EPU.[21]

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU 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 EPU, 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 EPU. 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 EPU acceptable with respect to the ESF atmosphere cleanup systems.

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[20] The accident of concern is a loss of offsite power (LOOP) concurrently with the design-basis LOCA.

[21] In addition to the changes due solely to EPU, the post-LOCA pH calculation includes updated methods consistent with current techniques used for this type of calculation. The overall conclusion from this updated calculation confirmed that the original methods were found to be reasonable and acceptable, and that the updated methods ensure the results are conservative. The updated evaluation indicates that the unbuffered case is further reduced from 10 days to 30 hours, and the final pH at 30 days is changed from 8.3 to 8.16 days. Therefore, the required time to reach mixing equilibrium of 4.4 hours is still significantly less than 30 hours.

2.7.3 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 control room personnel and to support the operability of control room components during normal operation, AOOs, and DBA conditions. The NRC's review of the CRAVS focused on the effects that the proposed EPU 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 control room 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; 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 NRC staff reviewed the license amendment application, supporting calculation NEDC-33351, and the NMP2 USAR. NEDC-33351 addresses the effects of the EPU equipment due to a loss of ventilation due to Station Blackout (SBO). The evaluation states the original SBO analysis bounds the EPU.

The Control Room Area Ventilation System (CRAVS) maintains temperature and humidity conditions suitable for personnel comfort and for equipment reliable operation inside the control room envelope, which includes MCR, the Relay Room, and HVAC Equipment Room with Control Room Emergency Filtration (CREF) Units. The CRAVS also maintains the control room envelope at positive pressure to inhibit air infiltration. Heat loads for the control room area envelope include boundary transmission, lighting and equipment such as control room panels.

NEDC-33351 states the heat loads for the control room envelope will not be affected by the slightly higher process temperatures that may result from the EPU. The ability to maintain the control room will not be affected. Control room environmental conditions will remain suitable for personnel comfort and for equipment reliability.

The EPU does not alter the quantity of toxic gases on site or near the site.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ability of the CRAVS to provide a controlled environment for the comfort and safety of control room personnel and to support the operability of control room 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 EPU, and associated changes to parameters affecting environmental conditions for control room personnel and equipment. Accordingly, the NRC staff concludes that the CRAVS will continue to provide an acceptable control room environment for safe operation of the plant following implementation of the proposed EPU. 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 EPU 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 spent fuel pool equipment areas, permit personnel access, and control airborne radioactivity in the area during normal operation, AOOs, and following postulated fuel-handling accidents. The NRC staff's review focused on the effects of the proposed EPU 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 NMP2 design does not include a separate spent fuel pool area ventilation system. The Reactor Building Ventilation System provides normal ventilation to the Spent Fuel Pool Area and is described in Section 2.7.5. The Standby Gas Treatment System functions to control radionuclide inventory in the Spent Fuel Pool Area, and its EPU evaluation is described in Sections 2.5.2.1 and 2.6.6. The Engineered Safety Feature Ventilation System is described in Section 2.7.6 and provides ventilation cooling to this area when the secondary containment is isolated during some AOOs.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the SFPAVS. The review is included in the evaluation in Sections 2.7.5 and 2.7.6.

2.7.5 Auxiliary and Radwaste Area and Turbine Areas Ventilation Systems

Regulatory Evaluation

The function of the drywell ventilation system (DVS), radwaste area ventilation system (RAVS) 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 EPU on the functional performance of the safety related portions of these systems. The NRC's acceptance criteria for the DVS, RAVS 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

NMPNS used NEDC-33004P-A, Revision 4, "Constant Pressure Power Uprate," Class III, July 2003 (also referred to as CLTR) to evaluate the effects of the Constant Pressure Power Uprate on CLTR Power Dependent Heating, Ventilation and Air Conditioning systems.

NMPNS determined the Reactor Building ventilation system, Radwaste Building ventilation system, and the Turbine Building ventilation system are the only ventilation systems that are power dependent. The power dependent heating ventilation and air conditioning (HVAC) systems consist mainly of heating, cooling supply, exhaust, and recirculation units in the reactor, radwaste and turbine building.

The reactor, radwaste and the turbine building ventilation systems function to control concentration of airborne radioactive material in their service areas during normal operation They provide a means for movement of air from clean to progressively greater potentially contaminate areas prior to exhaust. These systems maintain the building at slightly negative pressure with respect to the outdoors to prevent unmonitored release due to air exfiltration.

The reactor building ventilation system performs three additional functions:

1) An ESF HVAC function that is described in Section 2.7.6
2) A drywell cooling function, and
3) A primary containment purge function.

Drywell ventilation is non-safety related, and consists of unit coolers within the drywell separated from the reactor building. This system provides an environment that ensures equipment performance within required temperature limits. EPU results in slightly higher process temperatures and small increases in the heat load due to higher electrical currents in some motors and cables.

The primary containment purge system in conjunction with the reactor building ventilation system and the Standby Gas Treatment System control primary containment atmospheric gas concentrations and atmospheric pressure during normal operation. The cooling function of the reactor building ventilation system is discussed in Section 2.7.6. These systems do not function to control the concentration of airborne radioactive material in these areas during AOOs, and after postulated accidents including fuel-handling accidents. The steam tunnel in the turbine building, the drywell, feedwater heater bay, heater drain pumps, feedwater pumps and condensate/condensate booster pump areas of the turbine building will see an increase in heat loads. The heat load in the turbine building steam tunnel increases due to the increase in the feedwater temperature.

NMPNS determined the steam tunnel area coolers and main ventilation direct supply air to this area are capable of removing the heat load change. The increase in heat load due to increased power requirements of the feedwater pump motors is within the capability of the pump area coolers. The increase in heat load due to increase in heater drain pump motors is within the capability of the pump coolers. The increase heat load due to increased power requirements of the condensate and condensate booster pump motors is addressed by the addition of supplemental coolers. NMPNS intends to implement a plant modification for the installation of four additional area coolers located near the condensate and condensate booster pumps. The modification is scheduled to be completed during the 2012 refueling outage N2R13. In the drywell, the increase in feedwater process temperature and slight increase in the recirculation pump motor horsepower are within the capability of the area coolers. NMPNS determined other areas (including radwaste area) are unaffected by the EPU because the process temperatures are bounded by the pre-EPU analysis.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ARAVS and TAVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU 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 EPU 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 EPU 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 ESF HVAC system is part of the Reactor Building Ventilation System consisting of local area cooling and recirculation units within the reactor building and auxiliary bays. EPU results in slightly higher process temperatures. This portion of the ESF HVAC system functions to control the concentration of airborne radioactive material in these areas during AOOs and after postulated accidents. The Standby Gas Treatment System, in conjunction with portions of the reactor building ventilation system, controls of the concentration of airborne radioactive material in the secondary containment after postulated accidents.

The primary containment purge system, in conjunction with the reactor building ventilation system and the Standby Gas Treatment System, control primary containment atmospheric gas concentrations and atmospheric pressure following postulated accidents in addition to the combustible gas control system.

NMPNS determined that none of the areas in the reactor building and auxiliary bays are affected by the EPU because the process temperatures remain relatively constant following postulated accidents.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on the ESFVS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU 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 EPU. 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 EPU. 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 EPU acceptable with respect to the ESFVS.

2.8 Reactor Systems

The NRC staff's safety conclusions with regard to reactor core-related technical areas for the NMP2 EPU request are based either on generic assessment or on plant-specific evaluation, and these bases are noted in each section of this SE.

NMPNS' technical basis, submitted as Attachment 11 of the application ([1] or Reference 1), is formatted in the same way as RS-001. Attachment 11 conveys General Electric-Hitachi (GEH[22]) report NEDC-33351P, Revision 0, "Safety Analysis Report for Nine Mile Point, Unit 2 Constant Pressure Power Uprate." This report is also referred to as the Power Uprate Safety Analysis Report (PUSAR). The NRC staff review of reactor systems which is described in Section 2.8 are also formatted according to the RS-001 numbering scheme.

The PUSAR is based on NEDC-33004 [Reference 4], which is an NRC-approved licensing TR (LTR) describing the generic and plant-specific evaluations that support boiling water reactor (BWR) power uprates. The material contained in NEDC-33004 is based on two previously approved LTRs, ELTR1 and ELTR2 that had been used to support BWR EPUs: (1) NEDC-32424-P-A [Reference 18]; and (2) NEDC-32523P-A [Reference 19]. These three LTRs are referenced by NMPNS in their plant-specific application. The NRC staff's review effort in section 2.8 of this SE focused, mainly, on confirming the results and conclusions of these reports with respect to this application.

[22] General Electric (GE) and General Electric-Hitachi (GEH) are used interchangeably throughout this SE.

Another LTR, NEDC 33173P [Reference 20], is used by NMPNS, in this EPU application, to address the applicability of GE methodology to expanded operating domains. The NRC staff has generically approved the use of these GE analysis methods for BWR power uprate analyses, on an interim basis [Reference 21], pending improvement of GE's underlying, approved experimental and operating data bases. A review by the staff of the Nuclear Performance and Code Review Branch (SNPB), described in Section 2.8.7.1 of the conditions in this SE, has been performed to confirm that NEDC 33173P [Reference 20] has been applied in accordance with the conditions and limitations specified in the NRC's SE [Reference 21].

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, channel boxes, 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 anticipated operational occurrences[23] (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[24] (PAs); and

4. Coolability of the core 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 PAs. The NRC's acceptance criteria are based upon:

1. 10 CFR 50.46, insofar as it establishes acceptance criteria, and standards for the calculation and evaluation of emergency core cooling system (ECCS) 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; and

---

[23] AOOs, or incidents of moderate frequency, are defined in Appendix A to 10 CFR Part 50. AOOs are those conditions of normal operation that are expected to occur one or more times during the life of the nuclear power unit. This definition groups infrequent events into the AOO category.

[24] PAs, or limiting faults, are unanticipated occurrences (i.e., they are postulated; but not expected to occur during the life of the nuclear power plant).

3. 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 loss-of-coolant accident (LOCA).

Specific review criteria are contained in SRP Section 4.2 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

According to the Constant Pressure Power Uprate TR (CLTR) [Reference 4], the disposition for the fuel system design at EPU conditions is [[
]].

The NMP2 core has been transitioned to GE14 fuel in Cycle 10. NMP2 will continue to use only GE fuel types through the EPU implementation. NMPNS stated that no new fuel products will be introduced to implement the EPU, and that there are no changes to fuel design limits required by EPU. This information confirms the [[ ]] regarding fuel system design for NMP2 at EPU conditions, and the NRC staff finds this disposition acceptable.

The additional energy requirements for EPU are met by an increase in bundle enrichment, an increase in the reload fuel batch size, and/or changes in fuel loading pattern to maintain the desired plant operating cycle length. The power distribution in the core is changed to achieve increased core power, while limiting the minimum critical power ratio (MCPR), linear heat generation rate (LHGR), and maximum average planar linear heat generation rate (MAPLHGR) in any individual fuel bundle to be within limits as defined in the core operating limits report (COLR).

NMP2 is currently licensed to use uranium-dioxide fuel that has a maximum enrichment of 4.95 percent by weight uranium-235. The typical average enrichment is approximately 4.20 percent by weight uranium-235. For the proposed EPU, the core design would use a somewhat higher fuel enrichment (4.36 percent), which remains within the licensed maximum enrichment. The EPU fuel batch size will increase from 276 bundles to 352 bundles. The average fuel assembly discharge burnup would be approximately 48,000 MWd/MTU, [[

]].

While the EPU will require some modifications to the core design, the fuel design itself does not change. The parameters provided by the licensee, in their application, confirm that there is no significant or fundamental change to the fuel assembly design. Although there will be no fundamental change to the fuel design, the core loading, design and operation will change to allow for the loading of increased energy into the core. These core design changes are discussed in Section 2.8.2, "Nuclear Design."

Conclusion

The NRC staff has reviewed the licensee's disposition related to the effects of the proposed EPU on the 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 EPU 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 PAs; and

4. Coolability of the core will always be maintained.

These considerations are based, in large part, on the fact that the fuel design does not change for the EPU, and that the generic fuel design is appropriate for the NMP2 specific EPU operating conditions.

Based on these considerations, the NRC staff concludes that the fuel system and associated analyses will continue to meet the requirements of 10 CFR 50.46, GDC-10, and GDC-35 following implementation of the proposed EPU.

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 AOOs 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:

1. Core power distribution,

2. Reactivity coefficients,

3. Reactivity control requirements and control provisions,

4. Control rod patterns and reactivity worths,

5. Criticality,

6. Burnup, and

7. Vessel irradiation.

The NRC's acceptance criteria are based upon:

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 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 instrumentation and controls 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 of different design principles be provided, and that one of the systems be capable of holding the reactor subcritical in the cold condition;

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 reactor vessel internals so as to significantly impair the capability to cool the core.

Specific review criteria are contained in SRP Section 4.3 and other guidance is provided in Matrix 8 of RS-001.

<u>Technical Evaluation</u>

NMPNS addresses several aspects of the nuclear design for the proposed EPU conditions, including:

1. Core Design

2. Fuel Thermal Margin Monitoring

3. Thermal Limits

4. Reactivity Characteristics

5. Interim Methods Applicability

Items 1-4 are addressed by the NRC staff in the present evaluation. Item 5, concerning the applicability of interim methods, is addressed in Section 2.8.7 of this SE.

Core Design

The licensee confirmed the [[ ]], stating that implementation of the EPU will increase the average power density of the core by increasing bundle enrichment and reload fuel batch size, and/or changing the fuel loading pattern [Reference 1]. The required changes are implemented in such fashion as to limit the impact on fuel safety parameters, which include the minimum critical power ratio (MCPR), the linear heat generation rate (LHGR) and maximum average planar LHGR (MAPLHGR).

In order to apply the CLTR disposition, the licensee is required to confirm that [[ ]]. The licensee stated that there is no change to the fuel design, and that [[ ]]. The NRC staff agrees, therefore, that the licensee has [[ ]], and accepts the CLTR disposition as applicable to NMP2 at EPU conditions. The NRC staff's agreement is based on the fact, as discussed in Section 2.8.1, that the licensee is using the GE-14 fuel product line, which is approved for use with the CLTR.

The acceptability of the core nuclear design also depends upon obtaining acceptable results for transient and accident analyses, at the proposed EPU conditions, as evaluated by the NRC staff in Section 2.8.5, Accident and Transient Analyses.

Since (1) NMPNS has adequately applied the CLTR disposition for core design; (2) acceptable results have been provided for accident and transient analyses or evaluations/dispositions; and (3) the NRC staff has confirmed that the nuclear design characteristics are basically consistent with the limitations on the GE14 bundle design characteristics, and the staff's CLTR experience base, the NRC staff concludes that the NMP2 core design is acceptable for the proposed EPU conditions.

Fuel Thermal Margin Monitoring

The NMP2 TSs require monitoring for margin to the fuel thermal limits. For example, Limiting Condition for Operation (LCO) 3.2.1 requires that all average planar LHGRs (APLHGRs) be less than or equal to the limits specified in the COLR. This LCO, and all other LCOs that pertain to the fuel thermal limits, applies whenever the thermal power is greater than or equal to 25 percent of Rated Thermal Power (RTP), i.e., the fuel thermal margin monitoring threshold.

[[

]].

Therefore, for the uprated NMP2 core, [[

]].

Below 25% RTP, there is a high margin on critical power. Transients, initiated at lower power levels (e.g., from 20% RTP) would not produce any limiting consequences.

The NRC staff finds that the licensee has provided adequate information to support their determination of the fuel thermal margin monitoring threshold, as rescaled to NMP2's EPU conditions.

Thermal Limits Assessment

Section 2.8.2.3 of the PUSAR [Reference 1] addresses the effect of the proposed EPU upon the MCPR safety and operating limits and upon the MAPLHGR and LHGR limits. The NRC's acceptance criteria require that the reactor core and the associated control and instrumentation systems be designed with appropriate margin to ensure that the SAFDLs are not exceeded during normal operation, including AOOs. Operating limits are established to assure that regulatory or safety limits are not exceeded for a range of postulated events (transients and accidents).

The safety limit minimum critical power ratio (SLMCPR) ensures that 99.9% of the fuel rods are protected from boiling transition during steady-state operation. The operating limit minimum critical power ratio (OLMCPR) assures that the SLMCPR will not be exceeded as result of an AOO.

Prior evaluations of EPUs have shown that the change in OLMCPR, which would result solely from an EPU, would be small. The OLMCPR will be determined for plant cycle-specific core design parameters using approved methods, as discussed in the PUSAR. As required by the CLTR and the cycle-specific reload licensing requirements, the licensee will perform plant cycle-specific reload analyses to establish the OLMCPR and MAPLHGR and LHGR operating limits, and demonstrate that the SLMCPR provides the appropriate safety margin for fuel cladding integrity.

The licensee stated that there can be a small increase in SLMCPR (less than 0.01), when operating at the higher EPU power level, due to a flatter power distribution [4]. The SLMCPR analysis reflects the actual plant core-loading pattern and is performed for each plant reload core [35]. [[

]].

The licensee confirmed the [[ ]] in the CLTR by stating that the [[

]]. The licensee also stated that the SLMCPR will include an adder (0.02) for increased core flow uncertainties during single recirculation loop operations.

[[

]]. The calculated values will be reported in the Supplemental Reload Licensing Report for the EPU core. The SLMCPR for single loop operation will normally be 0.01 or 0.02 greater than the SLMCPR for two loop operation. A 0.02 value shall be added to the calculated cycle-specific SLMCPR value for both the single-loop and two-loop SLMCPR as required by [Reference 29].

The NRC staff finds the licensee's fuel thermal limits acceptable for NMP2. The NRC staff's conclusion in this regard is based on the fact that the SLMCPR is analyzed using NRC-approved methods described in [Reference 22], and its applicability will be confirmed on a cycle-specific basis.

Also, the licensee will evaluate the OLMCPR [[
]]. The licensee stated that the EPU operating conditions have only a small effect on the MCPR Operating Limit. The OLMCPR is calculated by adding the change in MCPR due to the limiting AOO event to the SLMCPR. The OLMCPR is determined on a cycle-specific basis using NRC-approved methods, and the method does not change with the EPU.

The NRC staff accepts the licensee's disposition regarding the OLMCPR because the OLMCPR will be reassessed on a cycle-specific basis using NRC-approved reload licensing methods. The OLMCPR assessment is acceptable for uprate operation at NMP2.

Additional conservatisms in the SLMCPR and OLMCPR required for the interim implementation of GE/GNF analytic methods at the EPU expanded operating domain will be added and are addressed by the NRC staff in Section 2.8.7 of this SER.

The maximum average planar linear heat generation rate (MAPLHGR) operating limit is based on the most limiting LOCA conditions, and ensures compliance with the ECCS acceptance criteria in 10 CFR 50.46. For every reload, licensees confirm that the MAPLHGR operating limit for each reload fuel bundle design remains applicable [Reference 29]. The [[
]] contained in the CLTR is based on the fact that, not only do [[
]], but the MAPLHGR operating limits are generally unaffected by EPU implementation.

The licensee stated in the PUSAR that the Maximum LHGR Operating Limit is determined by the fuel rod thermal mechanical design and is not affected by EPU.

The licensee must ensure that plant operation is in compliance with the cycle-specific thermal limits (SLMCPR, OLMCPR, MAPLHGR, and maximum LHGR) and specify the thermal limits in a cycle-specific COLR as required by NMP2 TSs.

Reactivity Characteristics

The licensee will maintain all minimum shutdown margin requirements without change. The licensee checked for adequate margin to cold shutdown, evaluating shutdown using both the standby liquid control system and the control rods.

The higher core energy requirements of a power uprate may affect the hot excess core reactivity and can also affect operating shutdown margins. The general effect of a power uprate on core reactivity, as described in Section 5.7.1 of NEDC-32424-P-A [Reference 18], is applicable to an EPU. Based on experience with previous plant-specific power uprate submittals, the required hot excess reactivity and shutdown margin can typically be achieved for power uprates through the standard approved fuel and core reload design process. Plant shutdown and reactivity margins must meet NRC-approved limits established in GESTAR-II on a cycle-specific basis [Reference 23] and these are evaluated for each plant reload core. Additional hot excess reactivity and shutdown margin analyses are not specifically required for the EPU.

The reload core analysis will ensure that the minimum shutdown margin requirements are met for each core design and that the current design and TS cold shutdown margin will be met. Since the licensee will continue to confirm that the TS cold shutdown requirements will be met for each reload core operation, the staff finds this acceptable, and concludes that the NRC's acceptance criteria, outlined in Section 2.8.2.1, will continue to be satisfied.

GEH stated in the ELTRs, and reaffirmed in the CLTR, and the NRC staff agreed, that the fuel reactivity characteristics for the EPU [[ ]]. The licensee, therefore, confirmed that the NMP2 reactivity characteristics are consistent with [[ ]]. The licensee will evaluate the shutdown margin for the next, uprated core prior to implementation of the EPU, and for subsequent reload cores under EPU conditions.

Conclusion

The NRC staff has reviewed the licensee's assessment for NMP2, and concludes that it is consistent with the information and disposition described in the CLTR. In addition, the licensee will continue to perform plant-specific reload analyses to confirm that SAFDLs and RCPB pressure limits will not be exceeded during the planned cycles. Based on this, and in coordination with the reviews of the fuel system design, 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, and therefore, is acceptable to the NRC staff.

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 NRC's acceptance criteria are based upon:

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 the effects of AOOs; and

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.

Specific review criteria are contained in SRP Section 4.4 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Summary of Technical Information

NMPNS has provided a technical evaluation of the proposed EPU from the thermal-hydraulic point of view as required by RS-001. Reload safety analyses will continue to be performed under EPU using approved methods to demonstrate compliance with thermal and hydraulic safety limits. Based on the evaluation, NMPNS concludes that EPU affects two thermal-hydraulic items that require special attention: (1) stability, and (2) ATWS-stability. The staff audited NMP2 on October 28, 2009. During the audit, the NRC staff reviewed the implementation of long-term stability solution Option III and found it acceptable. Information obtained during this audit supplements the information in NEDC-33351P for this review [Reference 1].

Stability Long Term Solution

NEDC-33351P, Revision 0, describes the Option III implementation in NMP2. The armed region in Option III is defined as percent power and flow (greater than 30% power and less than 60% flow). However, with the EPU to 120%, the percent power for the armed region is set to 26% to maintain the same region in terms of MW. This is an acceptable and recommended deviation of the approved Option III because the original Option III approval did not envision the possibility of power uprate. This modification maintains the same level of stability protection.

Option III requires the combination of local power range monitor (LPRM) signals in a series of oscillation power range monitor (OPRM) channels, which are similar in nature to the existing average power range monitor (APRM) channels, differing only on the LPRM grouping. APRM channels attempt to average LPRM signals from all over the core. OPRM channels average LPRM signals from specific regions in the core, so that they can detect regional or out-of-phase oscillations. APRM channels are not sensitive to out-of-phase oscillations because they average them out. The LPRM groupings in the OPRM channels are designed to avoid this problem. NMP2 committed to a full Long Term Solution implementation of Option III (OPRM) in November 1994, and installed the NUMAC power range neutron monitor (PRNM) with OPRM indication in April 1998. Between 1998 and 2000, NMP2 tested the OPRM system, and armed it in April 2000 NMP2 using the approved generic DIVOM (Delta CPR Over Initial MCPR Versus Oscillation Magnitude) slope. Overall, the experience of the OPRM system in NMP2 has been positive, and it correctly scrammed the reactor when unstable oscillations were detected in July 2003. Following the recent BWROG recommendations, NMP2 has implemented cycle-specific DIVOM calculations.

NMP2 implements Backup Stability Protection (BSP) as the stability licensing basis if the Option III OPRM system is declared inoperable. The BSP Scram and Controlled Entry region for EPU conditions are calculated with the same Option III methodology used in the NMP2 fuel cycle reload stability analysis, and it follows the BWROG recommendations. To calculate the BSP Scram and Controlled Entry Region boundaries, ODYSY decay ratio calculations are performed on the highest licensed flow control line and on the natural circulation line. Rated feedwater temperature and rated xenon concentrations are assumed for calculating the BSP Scram Region boundary points, and the points where a 0.8 core wide decay ratio is calculated are connected using well defined Shape Functions (e.g. Generic Shape Function) to define the Scram region boundary. The BSP Controlled Entry Region is calculated in a similar manner, also using a core wide decay ratio of 0.8 to define the region boundary; the difference being that the decay ratio calculation of the point on the highest flow control line assumes equilibrium feedwater temperature at off-rated operating condition and xenon concentration (rather than rated), and the point on the natural circulation line assumes equilibrium feedwater temperature and xenon free conditions.

When the OPRM system is operable in NMP2, the BSP scram region becomes an operator-enforced exit region. The BSP exit region procedures are enforced even if OPRM is operable. Under all conditions, an immediate scram is enforced following a two-pump recirculation pump trip (RPT). The BSP actions are defined in NMP2 internal procedure N2-SOP-29, which was reviewed by the staff during the October 28, 2009, audit.

The NMP2 OPRM system has implemented the lessons learned from the July 2003 NMP2 and Fitzpatrick stability events. The low-pass corner frequency of the OPRM algorithm and period tolerance values are set to the recommended values of 1 Hz and 100 ms, respectively.

In the NMP2 implementation, the licensing basis protection is provided by the standard Solution III Period Based Detection Algorithm (PBDA). As with all standard Solution III implementations, the other two defense in depth algorithms (growth rate and large oscillation algorithms) are present and would scram the reactor; however, no analysis is required to ensure that the defense in depth algorithms protect against SAFDL's for every possible scenario. Only the PBDA setpoint value is determined to ensure that SFADL's are protected with a high likelihood.

A 5% OPRM setpoint calibration error has been applied to account for the possible presence of voids in the bypass region. This is consistent with GEH EPU Interim Methods.

ATWS-Stability

NMPNS has performed an evaluation of the ATWS-Stability event. For this event, a turbine trip with bypass is assumed, followed by failure to scram. When the extraction steam is lost as a result of the turbine trip, the feedwater temperature cools down, which causes a significant power increase and very large unstable power oscillations may develop. The ATWS stability mitigation actions were designed to minimize the impact of this very severe event.

In NEDC-33351P, NMPNS evaluates the ATWS-Stability event at EPU conditions and concludes that the generic ATWS-Stability analysis of record in NEDO-32164 is applicable to NMP2 under EPU conditions. NMPNS bases this conclusion on the fact that the [[ ]] and, thus, following the recirculation pump trip prescribed by the ATWS rule, the reactor will be in similar conditions before or after EPU is implemented. In addition, NMP2 implements the ATWS-Stability mitigation actions automatically. Boron injection is initiated automatically with a 98 second delay if high pressure is sensed with power >4%. An automated FW flow runback is enforced if an ATWS is detected (high pressure and power >4%). This runback results in an automated lowering of the reactor pressure vessel (RPV) water level, which is very effective in reducing the reactor power. Therefore, ATWS-Stability oscillations are expected to be mitigated early and result in smaller amplitude in NMP2 than in the analysis of record.

The staff audit on October 28, 2009, reviewed the NMPNS ATWS procedures and witnessed three ATWS events (i.e., turbine trip ATWS from MELLLA corner, MSIV isolation from MELLLA corner, and MSIV isolation from EPU conditions) in the plant simulator. All events were handled properly by the operators and the reactor was successfully shutdown without exceeding the ATWS criteria, which are based on core coolability, pressure boundary limits, and radiation release from containment. The staff notes that the NMP2 simulator was not qualified at the time for EPU conditions and only the power and flow were changed, however, the NMPNS commits that the MSIV isolation ATWS scenario at EPU conditions will be run as a part of project implementation and a comparison of the results of this scenario with a similar CLTP scenario will be made available for review when the NMP2 simulator is upgraded for EPU conditions prior to the 2012 startup.

Summary of Technical Findings

The NRC staff's findings in regard to thermal-hydraulic design are based on the following considerations:

The staff performed an on-site audit of the impact of EPU on instability and ATWS in the NMP2 on October 28, 2009. NMP2 has submitted a license amendment in May 2009 to increase the operating thermal power by 15% from 3467 to 3988 MWth and implement an EPU.

To manage ATWS events, NMP2 has implemented the most recent Emergency Procedure Guidelines and Severe Accident Guideline (EPG/SAG) Revision 2. The staff reviewed the plant-specific emergency operating procedures (EOPs) for ATWS procedures. These instructions were then used in the plant simulator for a series of demonstration ATWS events.

EOP charts were reviewed by the staff during the audit. In addition, the EOP charts were followed in the simulator during the simulated ATWS events. The EOP implementation at NMP2 appears to be adequate.

Three ATWS transients were performed in the plant simulator during the staff audit. The operators followed the EOPs, and the plant was brought to a safe shutdown for all transients without requiring emergency depressurization. The heat capacity temperature limit (140 °F at full pressure) was never reached. Net positive suction head (NPSH) limits for ECCS equipment were never challenged.

The ATWS transients that were analyzed in the plant simulator are described in detail in the audit report (included as Appendix A to this report). The transients include:

(1) Turbine trip ATWS from the MELLLA corner
(2) MSIV isolation ATWS from MELLLA corner
(3) MSIV isolation ATWS from EPU conditions

Overall, the NMP2 operators promptly and effectively followed the EOPs as instructed. The ATWS EOPs are not extremely time sensitive; the three operators can easily handle in a timely manner the actions required to bring this scenario to a safe shutdown.

Conclusions

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the thermal and hydraulic design of the core and the RCS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the thermal and hydraulic design and demonstrated that the design (1) has been accomplished using acceptable analytical methods, (2) is equivalent to 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 EPU 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 and Generic Letter 94-02 [Reference 33] following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU 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 upon:

(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 reactor vessel internals so as to significantly impair the capability to cool the core;

(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; and

(8) 10 CFR 50.62(c)(3), insofar as it requires that all BWRs have an alternate rod injection (ARI) system diverse from the reactor trip system, and that the ARI system have redundant scram air header exhaust valves.

Specific review criteria are contained in SRP Section 4.6 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The NMP2 CRDS is described in Section 4.6 of the NMP2 USAR. The CRDS is used to position movable rods to control the neutron flux distribution in the core. The basic drive mechanism is a double-acting, mechanically latched, hydraulic cylinder that uses water as the operating fluid. The water also serves to cool the drive mechanism. The hydraulic drive is used for controlled insertion and withdrawal of control rods.

The rods also have a scram function. The CRD Hydraulic Control Unit (HCU) accumulator supplies the initial scram pressure and, as the scram continues, the reactor becomes the primary source of pressure to complete the scram. [Reference 1]

The licensee addressed three topics in its evaluation of the functional design of the control rod drive system:

- Control Rod Scram
- Control Rod Drive Positioning and Cooling
- Control Rod Drive Integrity

Control Rod Scram

Since the nominal reactor dome pressure for EPU does not change, the scram time, under EPU conditions, would remain the same as the scram time, under current conditions, and the current TS scram requirements would not be changed.

For pre-BWR/6 plants, the generic scram times for American Society of Mechanical Engineers (ASME) overpressure protection and critical power ratio pressurization transient analyses are not adversely affected by the reactor transient pressure and, therefore, remain valid. NMP2 is a BWR/5 plant. Therefore, the NMP2 CRD system control rod scram is [[ ]].

The licensee stated that the scram times are decreased by the transient pressure increase, which causes the [[ ]]. This is because, as indicated in the PUSAR, while the CRD hydraulic control unit supplies the initial scram pressure, the reactor becomes the primary source of pressure to complete the scram.

Because the steady-state operating pressure does not change due to the EPU, the initial pressure against which the HCUs must provide drive pressure to the control rod to attain the scram function would not change appreciably. Therefore, the initial rapid acceleration of the control rod for which the HCU is required would still be attained, and the reactor pressure would provide the motive force necessary to complete the scram at uprated conditions. The NRC staff agrees, therefore, that the scram performance relative to current plant operation is the same.

TS 3.1.4 provides requirements and acceptance criteria for scram time testing. The licensee must demonstrate in accordance with the surveillance requirements of TS 3.1.4 that the scram performance of the CRD system is within the analyzed capability of the scram system. The licensee has not requested to change these requirements in concert with the EPU request; therefore, the licensee will be required to demonstrate that the EPU has not affected the control rod scram performance.

The licensee concluded that the [[ ]]. The NRC staff, as described above, agrees with this disposition. The NRC staff also notes that the scram function of the control rod drive system must also be verified in accordance with TS SR 3.1.4, and that the licensee has requested no change to this TS. Based on these two considerations, the NRC staff finds the control rod scram performance acceptable for the requested EPU.

Control Rod Drive Positioning and Cooling

The NRC staff's SE approving the CLTR states that the normal CRD positioning function is an operational consideration and not a safety related function.

Notwithstanding this information, the CLTR states that the increase in reactor power at the NEDC-33004P-A operating condition results in a [[ ]]. GE has generically concluded that this [[ ]] from the CRD system to the CRDs during normal plant operation, and thus, that [[ ]] by NEDC-33004P-A implementation. The PUSAR states that automatic operation of the CRD system flow control valve maintains the required drive water pressure and cooling water flow rate.

To offer some order of magnitude for this change at the core plate, the NRC staff has observed that other BWR utilities implementing NEDC-33004P-A have quantified the change as [[ ]], which is also consistent with the change identified in [Reference 1].

The licensee confirmed the [[ ]], adding that [[ ]]. The NRC staff estimates that the valve has adequate margin to compensate for the changes expected at the core plate. In light of the changes that occur at the core plate during operation under EPU conditions, and the licensee's confirmation of adequate margin to compensate for these changes, the NRC staff agrees with the licensee's [[ ]] and finds the requested NEDC-33004P-A acceptable with respect to control rod drive positioning and cooling.

Control Rod Drive Integrity Assessment

The CLTR states that the constant pressure power uprate causes an increased transient pressure response, which poses a potential to create higher pressure loadings. With respect to the CRD design, according to the CLTR, the postulated abnormal operating condition assumes a failure of the CRD system pressure-regulating valve that applies the maximum pump discharge pressure to the CRD mechanism internal components. This postulated abnormal pressure bounds the ASME reactor overpressure limit.

The CLTR states further that the [[ ]].

The licensee confirmed that the maximum pressure for the ASME reactor pressure vessel overpressure is 1316 psig, compared to the ASME limit of 1375 psig. Therefore, the licensee confirmed the [[ ]] and the NRC staff agrees that this disposition is acceptable. The NRC staff finds the proposed EPU acceptable with respect to the integrity of the control rod drive system.

Conclusion

The NRC staff has reviewed the licensee's plant-specific evaluation related to the effects of the proposed EPU on the functional design of the CRDS. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system's ability to perform a safe shutdown, respond within acceptable limits, and prevent or mitigate the consequences of postulated accidents (PAs) following the implementation of the proposed EPU.

The NRC staff further concludes that the licensee has demonstrated that sufficient technical basis exists to ensure the system's design bases will continue to be followed upon implementation of the proposed EPU. The present design satisfies the GDCs under which the plant was licensed. No system changes are required for EPU, so the system design will continue to meet the GDCs and current licensing bases in this technical area. Based on these considerations, the NRC staff concludes that the CRD system and associated analyses will continue to meet the requirements of GDCs 4, 23, 25, 26, 27, 28, 29, and 10 CFR 50.62(c)(3) following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU 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 reactor protection system. The NRC staff's review covered relief and safety valves on the main steam lines and piping from these valves to the suppression pool. 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 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.

Specific review criteria are contained in SRP Section 5.2.2 and in Matrix 8 of RS-001.

Technical Evaluation

Overpressure protection and the reactor pressure relief system are discussed in Sections 5.2.2 and 5.4.13 of the NMP2 USAR. The safety/relief valves (SRVs) provide over-pressure protection for the nuclear steam supply system (NSSS), preventing failure of the nuclear system pressure boundary and uncontrolled release of fission products. The NMP2 USAR indicates that the NMP2 main steam system is equipped with 18 SRVs to mitigate the overpressure transient, which is terminated by the reactor scram function.

The licensee stated in the PUSAR that no SRV setpoint increase is needed for the requested EPU because there is no change in the dome pressure or simmer margin. Because of this, there is no effect on the valve functionality. The NRC staff accepts this conclusion.

The licensee evaluated the main steam isolation valve closure with scram on high flux (MSIVF), which has been shown to be the limiting event for overpressure when compared to the other potentially limiting event, the turbine trip with bypass failure and scram on high flux (TTNBP).

GE's analyses have shown, as discussed in the CLTR, that the MSIVF typically exceeds the TTNBP in limiting pressure by about 24-40 psi. The NRC staff accepted this conclusion as set forth in its SE for the CLTR. Based on the licensee's [[ ]] of event selection, the NRC staff accepts the licensee's overpressure evaluation based on the MSIVF event.

The SRV setpoints are established to provide the over-pressure protection function while ensuring that there is adequate pressure difference (simmer margin) between the reactor operating pressure and the SRV actuation setpoints. The SRV setpoints are also selected to be high enough to prevent unnecessary SRV actuations during normal plant maneuvers.

NMP2-Specific Analytic Assumptions

The licensee's EPU analysis is based upon a couple of conservative assumptions. First, the licensee assumes that the direct scram on MSIV position indication fails, which delays the initiation of the reactor trip until the ensuing flux peak is detected. Second, the event initiates at a dome pressure of 1050 psia, which is higher than the nominal dome pressure of 1035 psia.

The licensee also assumes that two safety/relief valves are out of service, and the NMP2 TSs require the operability of 16 S/RVs. With 18 S/RVs installed at NMP2, the analysis assumes the availability of two fewer S/RVs than installed at the plant.

The overpressure protection analysis is performed assuming a starting power level of 102 percent of the EPU rated thermal power.

Using these assumptions, the licensee used the ODYN code as described in NRC-approved licensing TR NEDO-24154-A [Reference 24].

Analytic Acceptance Criteria

The licensee stated that the design pressure for the reactor vessel and RCPB remains unchanged at 1250 psig, with the acceptance limit remaining at 110 percent of the design value, 1375 psig.

NMP2 TS 2.1.2 provides a safety limit (1325 psig) for the maximum calculated reactor dome pressure. The maximum calculated reactor dome pressure is 1286 psig. As discussed below, the analysis demonstrates acceptable performance relative to this safety limit.

Evaluation of Analytic Results

The licensee stated that the maximum reactor dome pressure is 1286 psig, with a corresponding peak reactor vessel pressure, located at the bottom of the reactor vessel, of 1316 psig. The peak pressure calculated for this transient remains below 1375 psig, and the calculated peak dome pressure remains below the TS 2.1.2 safety limit of 1325 psig. Based on the predicted peak pressures remaining below their respective limits, the NRC staff concludes that the overpressure protection analysis demonstrates that the proposed EPU is acceptable with respect to overpressure protection during power operation.

Conclusion

The NRC staff has reviewed the licensee's generic and plant-specific analyses related to the effects of the proposed EPU on the overpressure protection capability of the plant during power operation. In addition, the licensee will continue to perform plant-specific reload analyses for each cycle to confirm that SAFDLs and RCPB pressure limits will not be exceeded during the planned cycle.

Based on this information, the NRC staff concludes that the overpressure protection features will continue to meet GDCs 15 and 31 following implementation of the proposed EPU and, therefore, is acceptable to the NRC staff. The NRC staff also finds that the licensee has demonstrated that the proposed EPU will not challenge the safety limit contained in TS 2.1.2, the Reactor Coolant System Pressure Safety Limit.

2.8.4.3 Reactor Core Isolation Cooling System

Regulatory Evaluation

The reactor core isolation cooling (RCIC) system serves as a standby source of cooling water to provide a limited decay heat removal capability whenever the main feedwater system is isolated from the reactor vessel. In addition, the RCIC system may provide decay heat removal necessary for coping with a station blackout. The water supply for the RCIC system comes from the condensate storage tank, with a secondary supply from the suppression pool.

The NRC staff's review covered the effect of the proposed EPU on the functional capability of the system. 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 demonstrated that sharing will not impair its ability to perform its safety function;

(3) 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;

(4) GDC-33, insofar as it requires that a system to provide reactor coolant makeup for protection against small breaks in the RCPB be provided so the fuel design limits are not exceeded;

(5) GDC-34, insofar as it requires that a residual heat removal 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;

(6) 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

(7) 10 CFR 50.63, insofar as it requires that the plant withstand and recover from an SBO of a specified duration.

Specific review criteria are contained in SRP Section 5.4.6 and in Matrix 8 of RS-001.

Technical Evaluation

The NMP2 RCIC system is described in Section 5.4.6 of the NMP2 USAR. The RCIC system is required to maintain sufficient water inventory in the reactor to permit adequate core cooling following a reactor vessel isolation event accompanied by loss of flow from the feedwater system (LOFW). The system design injection rate must be capable of maintaining the reactor water level above top of active fuel (TAF) at EPU conditions. The water supply for the RCIC system comes from the condensate storage tank, with a secondary supply from the suppression pool. For the purposes of RCIC system evaluations, both the CST and the suppression pool water sources are considered.

NMPNS performed an evaluation of the RCIC for NMP2. The results of this evaluation indicate that the RCIC flow adequately maintains reactor vessel water level above TAF at EPU conditions. Specifically, the RCIC system maintains the water level outside the shroud above nominal Level 1 setpoint during a limiting LOFW event at EPU conditions. Thus, the RCIC injection rate meets its design-basis, i.e., to address the reactor vessel isolation event coincident with LOFW. The reactor system response to a LOFW transient with RCIC is discussed in Section 2.8.5.2.3.

The licensee's system performance and hardware evaluation confirms the [[ ]] for the RCIC system. Since the proposed EPU does not involve a change to the normal reactor operating pressure, the SRV setpoints remain unchanged. There is also no change to the maximum specified reactor pressure for RCIC system operation, and no change to the RCIC system performance parameters.

The NRC staff agrees with the disposition. The RCIC system performance and hardware are acceptable for the proposed EPU.

The Net Positive Suction Head (NPSH) available for the RCIC pump is unchanged, since there are no changes to the pump suction configuration, and no changes to the system flow rate or minimum atmospheric pressure in the suppression chamber or in the condensate storage tank (CST). The proposed EPU would not affect the capability to transfer the RCIC pump suction, on high suppression pool level or low CST level, from its normal alignment, the CST, to the suppression pool. Similarly, the proposed EPU would not affect the existing requirements for this transfer operation.

For ATWS and fire protection, operation of the RCIC system at suppression pool temperatures greater than the operational limit may be accomplished by using the dedicated CST volume as the source of water. Therefore, the specified operational temperature limit for the process water does not change with the EPU. The NPSH required by the RCIC pump does not change because there is no change to the maximum rated pump speed or the required pump flow rate. The effect of the proposed EPU on the operation of the RCIC system during SBO events is discussed in Section 2.3.5.

The RCIC system at NMP2 is [[
]]. No RCIC system power-dependent functions or operating requirements (flows, pressure, temperature, and NPSH) are added or changed from the original design or licensing bases.

The RCIC system at NMP2 is confirmed to be consistent with the generic description provided in the CLTR. No RCIC system power dependent functions or operating requirements (flows, pressure, temperature, and NPSH) are added or changed from the original design or licensing bases.

Loss of Feedwater Transient

The licensee stated that a plant-specific evaluation of the loss of feedwater (LOFW) transient confirms that the RCIC system performs adequately at the proposed EPU conditions. The LOFW analysis is discussed in Section 2.8.5.2.3 of the PUSAR.

Because the licensee has analyzed the LOFW transient for EPU operation, and has conservatively evaluated the pressure performance requirements of the NMP2 RCIC system, the NRC staff accepts the licensee's assessment that the RCIC will continue to meet the NRC's acceptance criteria as outlined in Section 2.8.4.3.1, above.

Conclusion

The NRC staff has reviewed the licensee's generic and plant-specific analyses related to the effects of the proposed EPU on the ability of the RCIC system to provide decay heat removal following an isolation of main feedwater event (or LOFW) or a station blackout event, and to provide makeup to the core following a small break in the RCPB. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on these events and demonstrated that the RCIC system will continue to provide sufficient decay heat removal and makeup for these events following implementation of the proposed EPU.

Based on these considerations, the NRC staff concludes that the RCIC system will continue to meet the requirements of GDCs 4, 5, 29, 33, 34, 54, and 10 CFR 50.63 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RCIC system.

2.8.4.4 Residual Heat Removal System

Regulatory Evaluation

The Residual Heat Removal (RHR) system is used to cool down the RCS following shutdown. The RHR system is a low pressure system which takes over the shutdown cooling function when the RCS pressure and temperature are reduced.

The NRC staff's review covered the effect of the proposed EPU 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 in Matrix 8 of RS-001.

Technical Evaluation

The NMP2 RHR system is described in Section 5.4.7 of the NMP2 USAR. The RHR system is designed to restore and maintain the reactor coolant inventory following a LOCA and remove reactor decay heat following reactor shutdown for normal, transient, and accident conditions. For NMP2, the RHR system is designed to operate in the LPCI mode, shutdown cooling mode, suppression pool cooling mode, containment spray cooling mode, fuel pool cooling assist mode, and steam condensing mode (SCM). This section of the NRC staff's SE addresses the shutdown cooling mode of the residual heat removal system.

Other operational and safety objectives of the RHR system are evaluated in different sections of this SE. The LPCI mode is discussed in Section 2.8.5.6.2 of the PUSAR and in the NRC staff's SE. Suppression pool cooling and containment spray cooling are addressed in Section 2.6.5 of the PUSAR and this SE. The fuel pool cooling assist mode of RHR operation is addressed in Section 2.5.3.1.1 of the PUSAR and this SE.

The licensee briefly described the steam condensing mode of RHR, as installed at NMP2. SCM is not a safety related mode and is not routinely used. The SCM was designed to maintain the reactor in a hot standby condition when the reactor is isolated from the main condenser so that an equipment malfunction can be corrected. The objective of the SCM is to permit a timely return to power operation after the reactor is no longer isolated. The increased decay heat due to EPU increases the RHR system heat exchanger heat load duty. The effect of EPU extends condensing times and is only an operational consideration and is not a safety concern.[25]

According to the CLTR, the NEDC-33004P-A effect on the RHR system is caused by the higher decay heat in the core corresponding to the uprated power and the increased amount of reactor heat discharged into the containment during a LOCA. Higher decay loads will result in a longer time required to obtain the shutdown cooling objective, which is to remove sensible and decay heat within a certain time objective.

[25] By letter dated September 23, 2011, the licensee indicated that a subsequent plant modification retired the SCM of RHR system operations, and the SCM is no longer available.

The licensee has determined the effects of the EPU on RHR shutdown cooling, and has confirmed that cold shutdown, relying only on safety related systems, can be attained within 36 hours. There will be an increase in the normal reactor shutdown time, due to the EPU. This increase could affect outage schedules, and might have an effect on plant availability. However, it would not have an effect upon plant safety or design operating margins. Therefore, the NRC staff accepts the licensee's evaluation of shutdown cooling, and concludes that the licensee has demonstrated that the proposed EPU is acceptable with respect to the shutdown cooling mode of the RHR system.

Conclusion

The NRC staff has reviewed the licensee's plant-specific evaluation related to the effects of the proposed EPU on the RHR system. The NRC staff concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the RHR system will maintain its ability to cool the RCS following shutdown (i.e., remove decay heat).

Based on these considerations, 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 EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the RHR system.

2.8.4.5 Standby Liquid Control System

Regulatory Evaluation

The standby liquid control system (SLCS) provides backup capability for reactivity control independent of the control rod system. The SLCS functions by injecting a boron solution into the reactor to affect shutdown. The NRC staff's review covered the effect of the proposed EPU on the functional capability of the system to deliver the required amount of boron solution into the reactor.

The NRC's acceptance criteria are based on:

(1) GDC-26, insofar as it requires that two independent reactivity control systems of different design principles be provided, and that one of the systems be capable of holding the reactor subcritical in the cold condition;

(2) GDC-27, insofar as it requires that the reactivity control systems have a combined capability, in conjunction with poison addition by the ECCS, to reliably control reactivity changes under PA conditions; and

(3) 10 CFR 50.62(c)(4), insofar as it requires that the SLCS be capable of reliably injecting a borated water solution into the reactor pressure vessel at a boron concentration, boron enrichment, and flow rate that provides a set level of reactivity control.

Specific review criteria are contained in SRP Section 9.3.5 and in Matrix 8 of RS-001.

Technical Evaluation

The NMP2 SLCS is described in Section 9.3.5 of the NMP2 USAR. Both loops of the NMP2 SLCS are automatically actuated from the redundant reactivity control. The automatic operation feature of the SLCS is required, in the event of an ATWS, by 10 CFR 50.62 for plants that were granted construction permits before July 26, 1984 (NMP2's permit was issued on June 24, 1974); and have already been designed to include this feature. The SLCS can also be actuated manually, via two key locked spring-return switches. The SLCS pumps inject an isotopically enriched sodium pentaborate decahydrate ($Na_2B_{10}O_{16}\cdot 10H_2O$) solution into the core in order to bring the core to a cold, subcritical condition from full power, at any time, from beginning to end of cycle, with the reactor in the most reactive xenon-free state, and with all control rods in their fully withdrawn positions.

The licensee stated that the ability of the SLCS boron solution to achieve and maintain safe shutdown is not a direct function of the core thermal power, and therefore is not affected by EPU [Reference 1]. SLCS shutdown capability (in terms of the required reactor boron concentration) is reevaluated for each fuel load. No new fuel product line designs were introduced for EPU. The boron shutdown concentration of 780 ppm did not change for EPU. No changes were necessary to the solution volume/concentration or the boron-10 enrichment for EPU to achieve the required reactor boron concentration for shutdown. [[

]].

The licensee performed a plant-specific EPU ATWS analysis. As stated in section 2.2.4 of this SE, the licensee's review indicates that existing safety and relief valve set pressures remain valid for the EPU. Reactor pressure will increase following the limiting anticipated transient without a scram (ATWS) event under EPU conditions which results in a minimal margin between the SLC pump discharge relief valve set pressure and reactor vessel pressure. By letter dated February 19, 2010 (ML100550601), the licensee responded to an NRC staff RAI (RAI G3) stating that the SLC pump discharge piping design pressure will be rerated to a higher pressure (1600 psig); and the SLC pump discharge relief valve set pressure will be increased to provide adequate margin. This modification was completed during the NMP2 2010 refueling outage (ML112450479).

The licensee stated that the peak reactor upper plenum pressure following the limiting ATWS event reaches 1221.3 psig during the time the SLCS is analyzed to be in operation. There is a corresponding increase in the maximum pump discharge pressure to 1326.4 psig and a decrease in the operating pressure margin for the pump discharge relief valves. For NMP2 EPU conditions, the relief valve setpoint margin is 31.6 psi, based on a SLCS pump relief valve setpoint of 1358 psig (1400 psig minus 3 percent tolerance). The pump discharge relief valves are periodically tested to maintain this tolerance. Therefore, the current SLCS process parameters associated with the minimum boron injection rate are not changed.

In the event that the SLCS is initiated before the time that reactor pressure recovers from the first transient peak, resulting in opening of the SLCS relief valves, the reactor pressure must reduce sufficiently to ensure SLCS relief valve closure. The licensee stated that the analytical results indicate pump discharge relief valve would reclose before the time that the reactor pressure recovers from the first transient peak. The licensee also stated that consideration was given to the system flow, head losses for full injection, and cyclic pressure pulsations due to the positive displacement pump operation in determining the pressure margin to the opening setpoint for the pump discharge relief valves, consistent with concerns identified by the NRC staff in IN 2001-13, "Inadequate Standby Liquid Control System Relief Valve Margin."

10 CFR 50.62(c)(4) requires that each BWR must have an SLCS with a minimum flow capacity and boron content equivalent in control capacity to 86 gpm of 13 weight percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch inside diameter reactor pressure vessel for a given core design. For ATWS, the equivalency requirement of the rule can be met if the following relationship is satisfied:

$(Q/86) \times (M251/M) \times (C/13) \times (E/19.8) > 1$

where:

Q= expected SLCS flow rate (gpm)
M= mass of water in the reactor vessel and recirculation system at hot rated condition in lbs
C= sodium pentaborate solution concentration (weight percent)
E= Boron-10 isotope enrichment (19.8 percent of natural boron)
M251= mass of water in a 251-inch inside diameter reactor vessel (lbs)

The licensee performed plant-specific calculations to verify that the SLCS complies with the ATWS rule referred above. Using the following NMP2-specific values to satisfy the relationship given above, the licensee established the bases for meeting the ATWS rule.

Q= 82.4 GPM
C= 13.6 weight percent
M251/M = 1 (since NMP2 has a 251-inch diameter reactor vessel)
E = 25.0

$(82.4 / 86) \times (1) \times (13.6 / 13) \times (25.0 / 19.8) > 1$
$1.266 > 1$

The SLCS is sized to inject at the maximum reactor pressure, i.e., at the highest analytical limit for the lowest group of SRVs operating in the safety relief mode. The proposed EPU does not affect the nominal reactor dome pressure or the SRV setpoints, and consequently, the capability of the SLCS to provide its backup shutdown function. The SLCS is not dependent upon any other SRV operating modes. The proposed EPU also does not increase the boron injection rate requirement for maintaining the peak suppression pool water temperature limits, following the limiting ATWS event with SLCS injection.

Conclusion

The NRC staff has reviewed the licensee's analyses related to the effects of the proposed EPU on the SLCS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system will continue to provide the function of reactivity control independent of the control rod system following implementation of the proposed EPU.

Based on these considerations, the NRC staff concludes that the SLCS will continue to meet the requirements of GDCs 26, 27, and 10 CFR 50.62(c)(4) following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the SLCS.

2.8.4.6 Reactor Recirculation System Performance

The licensee provided Section 2.8.4.6, "Reactor Recirculation System Performance," which is evaluated in other sections of this SE as appropriate.

2.8.5 Accident and Transient Analyses

Transient and accident events to be addressed for an EPU are the same as those covered in the USAR. They are grouped into the categories of Regulatory Guide (RG) 1.70. Each event evaluated is assigned to one of the following categories:

1. Increase in Heat Removal by the Secondary System[26]
2. Decrease in Heat Removal by the Secondary System
3. Decrease in Reactor Core Coolant System Flow Rate
4. Reactivity and Power Distribution Anomalies
5. Increase in Reactor Coolant Inventory
6. Decrease in Reactor Coolant Inventory
7. Radioactive Release from a Subsystem or Component
8. Anticipated Transients without Scram (ATWS)

Within each of the first seven categories, events are grouped into two classes: AOOs and PAs, as defined in 10 CFR Part 50, Appendix A.

For AOOs, the Standard Review Plan (SRP)[27] lists the following analysis acceptance criteria:

1. Pressure in the reactor coolant and main steam system should be maintained below 110 percent of the design values according to the ASME Code, Section III, Article NB-7000, "Overpressure Protection;"

2. Fuel cladding integrity should be maintained to ensure that SAFDLs are not exceeded during normal operating conditions and AOOs;

3. An incident of moderate frequency (or AOO) should not generate a more serious plant condition unless another fault occurs independently.

Acceptance criteria for PAs are based upon the nature of each PA, and include assessments of fuel damage, radiological releases, specific pressure limits, and other criteria (e.g., 10 CFR 50.46 for LOCAs). PAs with the potential to yield limiting consequences are analyzed for each core reload. These transients are typically the events that involve a significant change in power, since large power changes have the most significant effect on MCPR.

[26] For a BWR, Secondary System refers to main feedwater and main steam systems
[27] SRP Chapter 15.0, NUREG-0800

Further guidance is provided in Matrix 8 of RS-001.

In each of the subsequent accident and transient analyses, presented in Section 2.8.5, the NRC staff's review considered the following aspects, as applicable:

1. Postulated initial core and reactor conditions,
2. Methods applied in the thermal and hydraulic analyses,
3. The sequence of events,
4. Effects (assumed and calculated) upon reactor system components,
5. Performance (including functional and operational characteristics) of the reactor protection system, and
6. The results of the transient analyses, and the application of operator actions.

2.8.5.1 Decrease in Feedwater Temperature, Increase in Feedwater Flow, Increase in Steam Flow, and Inadvertent Opening of a Main Steam 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. 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's acceptance criteria are based upon:

(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;

(3) GDC-20, insofar as it requires that the reactor protection system 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 Sections 15.1.1 through 15.1.1.4 and in Matrix 8 of RS-001.

Technical Evaluation

The limiting events with respect to a decrease in feedwater temperature and an increase in feedwater flow are [[ ]], respectively. The licensee confirmed that each of these events is within the NMP2 reload evaluation scope. The increase in steam flow, and inadvertent opening of a main steam relief or safety valve events were also addressed, and found to be [[ ]]. Thus, the licensee [[ ]].

In Reference 1, the licensee provided a table of methods used for analysis, and confirmed that the same methods were used for transient analyses as those discussed in NEDC-32424-P-A [Reference 18]; however, NEDC-32424-P-A does not specifically mention the analytic method used to analyze the loss of feedwater heating (LOFWH) event. The NRC staff, in RAI D9, requested the licensee to identify the computer code or method that was used to analyze the LOFWH event. The licensee's response stated that the LOFWH event will be analyzed in the cycle-specific reload licensing analyses using the methods described in GESTAR II [23]; in this case, using the PANACEA computer code. This information confirms that the 3D simulator, listed in NEDC-32424-P-A table, is indeed an NRC-approved computer code (PANACEA). The licensee's response clarifies that the LOFWH analysis is performed using NRC-approved codes and methods, and the response is, therefore, acceptable.

The NRC staff also requested, in RAI D10, an evaluation of the LOFWH transient at EPU conditions to confirm that the acceptance criteria, relative to fuel thermal-mechanical performance, are satisfied. The licensee's response indicated that the analysis was performed, and yielded acceptable results, indicating that the [[ ]] limits were met.

The limiting increase in steam flow event, according to the licensee, is [[ ]]. Therefore, the increase in steam flow event was [[ ]].

An inadvertent safety relief valve opening is [[ ]]. This event is not analyzed for the EPU.

In summary, the licensee applied [[ ]] for each event in the excessive heat removal category. The limiting events are within reload evaluation scope, and need not specifically be evaluated for the requested EPU. The NRC staff has accepted this disposition, consistent with the approach set forth in the CLTR. The licensee will perform plant-specific reload analyses, using NRC-approved methods, to confirm that fuel design limits and RCPB pressure limits will not be exceeded under EPU conditions for this class of transients. The NRC staff accepts the licensee's disposition of the excessive heat removal transients.

Conclusion

The NRC staff has reviewed the licensee's disposition regarding the excess heat removal events described above and concludes that the licensee's disposition has adequately accounted for operation of the plant at the proposed power level and is based on 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 these considerations, the NRC staff concludes that the plant will continue to meet the requirements of GDC 10, 15, 20, and 26 following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the events stated.

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; Closure of Main Steam Isolation Valve; and Steam Pressure Regulator Failure (Closed)*

Regulatory Evaluation

A number of initiating events may result in an unplanned increase in reactor pressure and decrease in heat removal from the core. 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'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 15.2.1-5 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The transients evaluated in this group included the following:

- Loss of external load
- Turbine trip
- Loss of condenser vacuum
- Closure of main steam isolation valve
- Steam pressure regulator failure (closed)

The limiting events in the loss of external load and turbine trip categories are acceptable for [[ ]] because they are within the NMP2 reload evaluation scope. Specifically, NMPNS will evaluate the generator load rejection with no steam bypass failure (LRNBP) and the turbine trip with no steam bypass failure (TTNBP) as a part of the cycle-specific reload analysis process.

The licensee stated that, for all BWRs, the loss of condenser vacuum (LOCV) event is [[ ]]. The NRC staff agrees with the licensee's disposition. The NRC staff finds that the LOCV need not be analyzed for the EPU because it is [[ ]], and is [[ ]]. This is consistent with the [[ ]], which the NRC staff finds acceptable.

The limiting main steam isolation valve closure (MSIVC) is the MSIVC with failure of direct scram. This transient is analyzed in support of the requested EPU, as evaluated by the NRC staff in Section 2.8.4.2 of this SE.

Because NMP2 is a BWR/5, the pressure regulator failure need not be analyzed. This is because, as stated by the licensee, this event [[ ]]. The NRC staff has previously accepted this disposition as indicated in the SE report approving the CLTR, and it is acceptable for the NMP2 EPU request on that basis.

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 these considerations, the NRC staff concludes that the plant will continue to meet the intent of GDCs 10, 15, and 26, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU 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 nonemergency AC power is assumed to result in the loss of all power to the station auxiliaries and simultaneous tripping of both reactor coolant circulation pumps. This causes a flow coast down as well as a decrease in heat removal via the steam 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's acceptance criteria are based upon:

(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 15.2.6 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The plant can lose all auxiliary power if all external grid connections are lost or if faults occur in the auxiliary power system itself. Section 9 of the CLTR [4] provides the disposition of the AOOs for constant pressure EPUs. The NRC staff reviewed and accepted this disposition. Loss of Auxiliary Power to the Station Auxiliaries is [[

]].

Conclusion

The NRC staff has reviewed the licensee's disposition regarding analysis of the loss of nonemergency AC power to the station auxiliaries event and concludes that the licensee's disposition adequately accounts for operation of the plant at the proposed power level and is based on analyses 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 these considerations, the NRC staff concludes that the plant will continue to meet GDCs 10, 15, and 26, following implementation of the proposed EPU. Therefore, the NRC staff finds that the proposed EPU is acceptable with respect to the loss of nonemergency AC power to the station auxiliaries event.

2.8.5.2.3 *Loss of Normal Feedwater Flow*

Regulatory Evaluation

A loss of normal feedwater flow could occur from pump failures, valve malfunctions, or a loss-of-off-site power (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 the fuel following a loss of normal feedwater flow. Reactor protection and safety systems are actuated to provide this function and mitigate other aspects of the transient.

The NRC's acceptance criteria are based upon:

(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 is provided in Matrix 8 of RS-001.

Technical Evaluation

Feedwater Control System failures or reactor feedwater pump trips can lead to partial or complete LOFW. LOFW results in a situation where the mass of steam leaving the reactor vessel exceeds the mass of water entering the vessel, resulting in a decrease in the coolant inventory available to cool the core.

Consistent with dispositions provided in [Reference 1], this loss-of-level event was evaluated, using the SAFER04 model for NMP2, to assure that, for the higher decay heat load of the EPU, the reactor coolant inventory can adequately keep the core covered [Reference 30]. The analysis is based upon operation at 102 percent of the EPU power level, and an initial water level at the low-level scram setpoint. The results of the complete LOFW analysis show that the water level inside the core shroud, above the top of active fuel, is maintained. It was assumed that the high-pressure core spray (HPCS) system failed, and that only the RCIC system was available to restore the reactor water level. The RCIC system is initiated when the reactor vessel water level decreases to the low-low level setpoint. Some additional time was required, by the RCIC system, to restore water level, due to the presence of a higher level of decay heat that would result from operation at EPU conditions. The ANS 5.1-1979 decay heat model was assumed, plus 10% for uncertainty. This bounds the ANS 5.1-1979 decay heat model, plus 2σ for uncertainty.

After the water level was restored, the operator controlled the water level, depressurized the reactor coolant system, and initiated RHR shutdown cooling. No new operator actions or shorter operator response times were required. Therefore, the operator actions, required to handle an LOFW event, would not be significantly different for an LOFW occurring at EPU conditions.

Additional details of the analysis were provided, by NMPNS, in response to a staff request in RAI D3 [Reference 28]. The results of the LOFW analysis demonstrate that the RCIC system, under LOFW conditions at the EPU power level, can maintain minimum reactor water level, throughout the transient, to levels greater than 153 inches above the top of active fuel. Because the licensee's analysis shows that an acceptable core water level is maintained, the NRC staff finds the licensee's analysis acceptable. The NRC staff also finds the licensee's evaluation of the associated operator actions to be acceptable.

NMPNS also addressed partial LOFW (i.e., the loss of a single feedwater pump) by referring to the [[ ]]. The licensee stated that the loss of a single feedwater pump addresses operational considerations to avoid reactor scram on low water level. The [[ ]] is acceptable for the loss of a single feedwater pump, provided that [[ ]]. The NRC staff finds the licensee's disposition of the loss of a single feedwater pump event acceptable.

Conclusion

The NRC staff has reviewed the licensee's analyses and dispositions of the decrease in reactor coolant flow events and concludes that the licensee's analyses and dispositions have adequately accounted for operation of the plant at the proposed power level and were either based on or 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 these considerations, the NRC staff concludes that the plant will continue to meet GDCs 10, 15, and 26. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the loss of normal feedwater flow event.

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's acceptance criteria are based upon:

(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 is provided in Matrix 8 of RS-001.

Technical Evaluation

Events in this group include Recirculation Flow Control Failure, Trip of One Recirculation Pump and Trip of Two Recirculation pumps.

Generic analyses performed for several BWRs have shown that the events in this category are not limiting events and are bounded by the more limiting transients, which, as the licensee stated, [[ ]].

Conclusion

The NRC staff has reviewed the licensee's disposition regarding the decrease in reactor coolant flow event and concludes that the licensee's disposition adequately accounts 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 these considerations, the NRC staff concludes that the plant will continue to meet GDCs 10, 15, and 26. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the decrease in reactor coolant flow event.

2.8.5.3.2 *Recirculation Pump Rotor Seizure or Shaft Break*

Regulatory Evaluation

The event postulated is an instantaneous seizure of the rotor or break of the shaft of a recirculation 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's acceptance criteria are based upon:

(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 reactor vessel internals 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 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.

Specific review criteria are contained in SRP Section 15.3.3-4 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The recirculation pump rotor seizure and shaft break events are design-basis accidents. Flow through the affected loop is rapidly reduced, leading to a reactor and turbine trip. The sudden decrease in core flow results in a degradation of core heat transfer; however, core uncovery is not expected during this accident.

Generic analyses performed for several BWRs have shown that the accidents in this category are not limiting events and are bounded by the more limiting accidents and hence these accidents are not included in the reload analyses. The licensee stated that [[

]].

Conclusion

The NRC staff has reviewed the licensee's dispositions and analyses of the sudden decrease in core coolant flow events and concludes that the licensee's dispositions and analyses have adequately accounted for operation of the plant at the proposed power level and based on or 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.

Note that the NRC staff's assurance that NMP2 will meet accident acceptance criteria for this event is based on the fact that it has been demonstrated that these events can be sustained and meet AOO acceptance criteria, which are more stringent than the accident acceptance criteria listed in this evaluation.

Based on this, the NRC staff concludes that the plant will continue to meet GDC 10 for the implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU 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 add positive reactivity to the reactor core, and cause a power excursion.

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 reactor protection system 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 is provided in Matrix 8 of RS-001.

<u>Technical Evaluation</u>

The uncontrolled control rod withdrawal event at subcritical or low power startup conditions is a localized, low power event. This event was evaluated in Section 5.1.2 of the CLTR [Reference 30] as a comparison of the expected maximum increase in peak fuel enthalpy for a 20 percent EPU against an acceptance criterion of 170 cal/gram, based on the methodology of [Reference 25]. Since this is a localized low-power event, and [[

]] the proposed EPU would not be expected to result in an increase in peak fuel enthalpy.[28]
[[

]]. Increasing the peak fuel rod enthalpy by 20 percent would result in a peak fuel enthalpy, under EPU conditions, of only 72 cal/gram, well below the acceptance criterion of 170 cal/gram.

In response to a staff request for additional information (RAI D11), NMPNS confirmed that the uncontrolled control rod assembly withdrawal from subcritical or low power startup conditions analysis is not performed on reload licensing basis. Instead, a generic study [Reference 25] is applied, and this generic study concludes that the event is non-limiting. The methods applied in the generic study are consistent with the methods used for the control rod drop accident analysis [Reference 26].

The NRC staff evaluated the licensee's response, and found it acceptable based on the following two considerations. First, the method used to evaluate the transient is acceptable. Second, the licensee justified the application of the method, for NMP2, under the proposed EPU conditions:

- Limitations on in-sequence rod worths and shutdown margin serve to limit peak fuel enthalpy on the startup RWE; this consideration does not change for the EPU, and

---

[28] Per NMP2 PUSAR Section 2.4.1.1, the [[

]]

- Increasing the peak fuel enthalpy by a factor of 1.2 still leaves significant margin to the licensing limit for this transient.

Conclusion

The NRC staff has reviewed the disposition of the uncontrolled rod withdrawal event at subcritical or low power conditions presented in the NMP2 EPU application, and concludes that the information presented in the application pertaining to this event is consistent with the expectations delineated in the SER associated with the CLTR. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that SAFDLs will not be exceeded as a result of these events. Based on these considerations, the NRC staff concludes that the plant will continue to meet GDCs 10, 20, and 25, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the uncontrolled control rod assembly withdrawal from a subcritical or low power startup condition.

2.8.5.4.2 *Continuous Control Rod Withdrawal during Power Range Operation*

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 the consistency of the licensee's disposition of the uncontrolled control rod assembly withdrawal at power with the [[ ]] approved by the NRC staff in the CLTR SER.

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 reactor protection system 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 is provided in Matrix 8 of RS-001.

Technical Evaluation

While operating in the power range, it is assumed that the reactor operator makes a procedural error and fully withdraws the maximum worth control rod. Due to the positive reactivity insertion, the core average power increases. If the Rod Withdrawal Error (RWE) is severe enough, the

Rod Block Monitor (RBM) will sound alarms, at which time the operator will take corrective actions. Even for extremely severe conditions i.e., for highly abnormal control rod patterns, operating conditions, and assuming that the operator ignores all the alarms and warnings and continues to withdraw the control rod, the fuel cladding integrity safety limit (MCPR) and fuel rod mechanical overpower limits will not be exceeded.

The NRC staff has reviewed NMP2's disposition of the RWE, and agrees with the assessment that RWE analysis is within the NMP2 reload scope as defined by the SER associated with the CLTR. This disposition is acceptable for the following reasons: [[

]]. This analysis will be carried out with NRC staff-approved methods and codes and the results documented in the Supplemental Reload Licensing Report.

Conclusion

The NRC staff has reviewed the disposition of the uncontrolled control rod withdrawal error at power presented in the NMP2 EPU application, and concludes that the content of the application pertaining to this event are consistent with the expectations delineated in the SER associated with CLTR. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that SAFDLs will not be exceeded as a result of these events. Based on this, the NRC staff concludes that NMP2 will continue to meet GDCs 10, 20 and 25, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the uncontrolled control rod withdrawal error at power.

2.8.5.4.3 *Core Coolant Flow Increase, Startup of Idle Recirculation Pump, Recirculation Flow Controller Failure*

Regulatory Evaluation

A startup of an inactive loop transient may result in either an increased core flow or the introduction of cooler water into the core. This event causes an increase in core reactivity due to decreases in moderator temperature and core void fraction.

The NRC staff's review covered the consistency of the licensee's disposition of the uncontrolled control rod assembly withdrawal at power with the [[ ]] approved by the NRC staff in the CLTR SER.

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-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 AOOs;

(3) GDC-20, insofar as it requires that the protection system be designed to initiate automatically the operation of appropriate systems to ensure that SAFDLs are not exceeded as a result of operational occurrences;

(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;

(5) 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 reactor vessel internals so as to significantly impair the capability to cool the core; and

Specific review criteria are contained in SRP Section 15.4.4-5 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Events in this category include recirculation flow controller failure-increasing flow and start-up of idle recirculation pump. Failure of the controller can cause a rapid increase in recirculation flow.

Start-up of an idle recirculation pump is a non-limiting transient for GE BWRs that are equipped with the APRM/Rod Block Monitor/Technical Specifications (ARTS) plant performance option.

The CLTR provides the basis for disposing this event, based on the fact that [[

]].

The disposition of the increase in core flow events is applicable to the NMP2 EPU, and confirmed, since [[

]].

Conclusion

The NRC staff has reviewed the disposition of the recirculation flow increase events presented in the NMP2 EPU application, and concludes that the content of the application pertaining to this event are consistent with the expectations delineated in the SER associated with CLTR. The NRC staff further concludes that the licensee has demonstrated that the reactor protection and safety systems will continue to ensure that 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 GDCs 10, 15, 20, 26 and 28, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the recirculation flow increase events.

2.8.5.4.4 *Control Rod Drop Accident*

Regulatory Evaluation

The NRC staff evaluated the consequences of a control rod drop accident (CRDA) with respect to reactor physics. The NRC staff's review covered the occurrences that lead to the accident, safety features designed to limit the amount of reactivity available and the rate at which reactivity can be added to the core, the analytical model used for analyses, and the results of the 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 reactor vessel internals so as to significantly impair the capability to cool the core.

Specific review criteria are contained in SRP Section 15.4.9 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

The CRDA, a design-basis accident that is reported in Section 15.4.9 of the NMP2 USAR, is postulated to be caused by the separation of a control rod from its drive. The blade remains stuck in its channel while the drive is withdrawn under it. At some point, the blade becomes unstuck and drops from the core at the maximum speed allowed by the velocity limiter, adding positive reactivity, and increasing power and energy deposition in the fuel (i.e., fuel enthalpy). As the energy deposition heats up the fuel, negative Doppler feedback is produced, which reduces power, until the reactor is scrammed.

A bounding generic evaluation of the CRDA for all BWRs using the Banked Position Withdrawal Sequence (BPWS) has been performed [Reference 27]. The methods applied in this study are consistent with those used for the CRDA analysis licensing TR [Reference 26]. The CRDA is a localized low-power event, and not evaluated on reload licensing basis.

The NMP2 EPU application [Reference 1] states [[

]].[29]

No change in peak fuel enthalpy is expected due to the proposed EPU; however, because of the fuel and core design changes necessary to sustain reactor operation at EPU conditions, there may be a resulting increase in control rod worth. Thus, the reactivity insertion due to a CRDA would be higher, with a correspondingly higher energy deposition in the fuel (i.e., a higher peak fuel enthalpy).

[29] Per NMP2 PUSAR Section 2.8.5.4.4, the [[

]]

The increase in rod worths as a result of core designs necessary to operate under EPU conditions is not expected to cause an excessive increase in peak fuel enthalpies. In response to a staff request [Reference 28] for additional information (RAI D12) NMPNS stated that if the peak fuel rod enthalpy that is generically determined for BPWS plants is increased by 20%, the peak fuel rod enthalpy at EPU will be only 162 cal/gm, well below the acceptance criterion of 280 cal/gram. Therefore, from a reactor physics standpoint, the consequences of the CRDA are acceptable.

The licensee also indicated that EPU fuel and core designs can lead to generally higher rod worth distributions, and therefore higher peak fuel enthalpy at low power; but that [[

]] associated with the BPWS.

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 Control Rod Drop event, at lower enthalpies than the limits currently specified in Section 4.2 of the 1981 Revision of the Standard Review Plan. However, generic analyses performed by all of the reactor vendors have indicated that the fuel enthalpy during RIAs will be much lower than the SRP 4.2 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 the analyses performed by the vendors, which have been confirmed by NRC-sponsored calculations, provide reasonable assurance that the effects of postulated reactivity initiated accidents (RIAs) in operating plants with fuel burnups up to 60 gigawatt days per metric ton uranium will neither (1) result in 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.

Conclusion

The NRC staff has reviewed the licensee's disposition of the control rod drop accident and concludes that the licensee's disposition has adequately taken into account the EPU impact on the control rod drop accident. Based on this consideration, the NRC staff concludes that the plant will continue to meet GDC-28 following implementation of the EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the control rod drop accident.

2.8.5.5 Core Coolant Flow Increase, Inadvertent Operation of ECCS or Malfunction that Increases Reactor Coolant Inventory – Feedwater Controller Failure

Regulatory Evaluation

Equipment malfunctions, operator errors, and abnormal occurrences could cause unplanned increases in reactor coolant inventory. Depending on the 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'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 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 Sections 15.5.1 and 15.5.2, and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Events in this category result in an increase in core coolant inventory. The increase in coolant inventory that is associated with these events also results in an increase in subcooling.

One of the potentially limiting events in this category is the feedwater controller failure to maximum demand, which in Section 2.8.5.1 of this SE.

The other potentially limiting event in this category is the [[ ]] system. This event is [[ ]]. This is consistent with the NRC-approved, [[ ]] contained in the CLTR, and therefore, is acceptable to the NRC staff.

Conclusion

The NRC staff has reviewed the licensee's disposition regarding the analysis of the inadvertent operation of ECCS or malfunction that increases reactor coolant inventory and concludes that the licensee's disposition adequately accounts for operation of the plant at the proposed power level and is based on acceptable analytic 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 these considerations, the NRC staff concludes that the plant will continue to meet GDCs 10, 15, and 26, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the inadvertent operation of ECCS or malfunction that increases reactor coolant inventory.

2.8.5.6 Decrease in Reactor Coolant Inventory

2.8.5.6.1 *Inadvertent Opening of a Pressure Relief Valve (IORV)*

Regulatory Evaluation

The inadvertent opening of a pressure relief valve results in a reactor coolant inventory decrease and a decrease in RCS pressure. The pressure relief valve discharges into the suppression pool. Normally there is no reactor trip. The pressure regulator senses the RCS pressure decrease and partially closes the turbine control valves (TCVs) to stabilize the reactor at a lower pressure. The reactor power settles to about the initial power level. The coolant inventory is maintained by the feedwater control system using water from the condensate storage tank via the condenser hotwell.

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 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 15.6.1 and other guidance is provided in Matrix 8 of RS-001.

Technical Evaluation

Inadvertent opening of a safety/relief valve will cause a decrease in reactor coolant pressure, which will cause the pressure regulator to close the TCVs, in order to maintain constant reactor vessel pressure. Reactor power will settle to nearly the initial power level. Automatic recirculation flow control will increase the recirculation flow to the maximum; but will not be able to meet the additional load demand.[30] The pressure regulator setpoint will be automatically reduced to its lower limit, and the reactor vessel pressure will decrease. This event will have only a slight effect on fuel thermal margins. The changes in fuel rod surface heat flux, and in the MCPR are expected to be very small. Therefore, the effects of this transient are bounded by more severe transients.

Conclusion

The NRC staff has reviewed the licensee's disposition regarding the inadvertent opening of a pressure relief valve event and concludes that the licensee's disposition has adequately

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[30] The IORV event is not a limiting EPU event and [[ ]]. Operation of recirculation flow control in automatic flow control mode is not permitted at NMP2.

accounted for operation of the plant at the proposed power level. The NRC staff further concludes that the licensee has demonstrated that the reactor pressure relief and control 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 these considerations, the NRC staff concludes that the plant will continue to meet GDCs 10, 15, and 26, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect the inadvertent opening of a pressure relief valve event.

2.8.5.6.2 *Emergency Core Cooling System and Loss-of-Coolant Accidents*

Regulatory Evaluation

A LOCA is a PA that is said to exist when there is a loss of reactor coolant, from a pipe break in the RCPB that cannot be replaced by the normal reactor coolant makeup system. Loss of a large amount of reactor coolant could impede or prevent heat removal from the reactor core. The reactor protection and ECCS systems are provided to mitigate LOCAs.

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 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 PA 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 is provided in Matrix 8 of RS-001.

Technical Evaluation

LOCA is design-basis accident (DBA), and not expected to occur during the lifetime of a plant. DBAs are PAs that nuclear facilities must be designed and built to withstand without loss to the systems, structures, and components necessary to ensure public health and safety. The ECCS is one of the systems necessary to ensure public health and safety. Specifically, the ECCS, described in Section 6.3 of the NMP2 USAR, is designed to provide cooling for postulated LOCAs caused by ruptures in primary system piping.

10 CFR 50.46 specifies design acceptance criteria, for LOCAs, based on (a) the peak cladding temperature (PCT), (b) local cladding oxidation, (c) total hydrogen generation, (d) coolable core geometry, and (e) long-term coolability. The LOCA analysis considers a spectrum of break sizes and locations against these acceptance criteria, including a circumferential rupture of the largest recirculation system pipe. Assuming a single failure in the ECCS, the LOCA analysis is used to identify the break sizes that most severely challenge the ECCS and the primary containment. The maximum average planar linear heat generation rate (MAPLHGR) operating limit is based on the most limiting LOCA analysis. LOCA analyses are performed for each new fuel type to demonstrate that the 10 CFR 50.46 acceptance criteria can be met.

The NMP2 ECCS consists of the HPCS system, the RHR system (when operating in the low-pressure coolant injection (LPCI) mode), the low-pressure core spray (LPCS) system, and the automatic depressurization system (ADS). NPSH requirements for the ECCS are evaluated in PUSAR Section 2.6.5 (RAI E10 [Reference 28]).

High Pressure Core Spray (HPCS)

The HPCS system is designed to pump water into the reactor vessel over a wide range of operating pressures. The primary purpose of the HPCS system is to maintain reactor vessel coolant inventory in the event of a small-break LOCA that does not immediately depressurize the reactor vessel. In this event, the HPCS system maintains reactor water level and helps depressurize the reactor vessel.

The CLTR provides for [[ ]] of HPCS performance, provided that licensees confirm the following requirements:

- [[ ]]
- [[ ]]
- [[ ]]

The licensee confirmed that these requirements are satisfied, with respect to the proposed EPU. The NRC staff finds that the licensee's application of the CLTR disposition for HPCS, under EPU conditions, is acceptable, since the generic requirements continue to be met.

Low Pressure Core Spray (LPCS)

The LPCS system is automatically initiated in the event of a LOCA. When operating in conjunction with other components of the ECCS, the LPCS system is required to provide adequate core cooling for all LOCA events. There is no change in the reactor pressure levels at which the LPCS is required to operate.

The LPCS system sprays water into the reactor vessel after it is depressurized. The primary purpose of the LPCS system is to provide reactor vessel coolant inventory makeup, following LOCAs of various break sizes, up to and including the large-break LOCA. It also provides long-term core cooling in the event of a LOCA.

The increase in decay heat due to the EPU could increase the calculated PCT following a postulated LOCA by a small amount. The ECCS performance evaluation demonstrates that the existing LPCS system performance capability, in conjunction with the other ECCS systems, as required, is adequate to meet the post-LOCA core cooling requirement for the EPU conditions. The licensee stated that the [[

]].

The NRC staff, therefore, accepts the licensee's assessment that EPU does not significantly impact operation of the LPCS system. Since the licensee's ECCS-LOCA analysis (see section below titled, "ECCS Performance") based on the current LPCS capability demonstrate that the system provides adequate core cooling, the NRC staff finds the evaluation acceptable, and agrees with the licensee's assessment that the LPCS will continue to meet the NRC's acceptance criteria.

Low Pressure Coolant Injection (LPCI)

The LPCI mode of the RHR system is automatically initiated in the event of a LOCA. The primary purpose of the LPCI mode is to help maintain reactor vessel coolant inventory for LOCAs of various break sizes, up to and including the large-break LOCA, after the reactor vessel has depressurized. The LPCI operating requirements are not affected by EPU. The increase in decay heat due to EPU could increase the calculated PCT following a postulated LOCA by a small amount. [[
]]. The ECCS performance evaluation demonstrates that the existing LPCI mode performance capability, in conjunction with the other ECCS, is adequate to meet the post-LOCA core cooling requirement for EPU RTP conditions. The licensee stated that [[

]].

Since the licensee's ECCS-LOCA analysis (see section below titled, "ECCS Performance") based on the current LPCI capability demonstrate that the system provides adequate core cooling, the NRC staff finds the evaluation acceptable, and agree with the licensee's assessment that the LPCI will continue to meet the NRC's acceptance criteria.

Automatic Depressurization System (ADS)

The ADS uses SRVs to reduce the reactor pressure following a small-break LOCA when it is assumed that the high-pressure systems have failed. After a specified delay, the ADS actuates either on low water level plus high drywell pressure or on sustained low water level alone. This allows the LPCS and LPCI to inject coolant into the reactor vessel.[31]

Plant design requires a minimum flow capacity for the SRVs, and that ADS initiates following confirmatory signals and associated time delay(s). The licensee stated that the ADS initiation logic and ADS valve control [[ ]] are adequate for EPU conditions.

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[31] In general, the NMP2 logic design for ADS initiated is as follows: (1) manual initiation AND at least one low pressure ECCS pump running or (2) RPV level 1 sustained for 105 seconds AND RPV level 3 (confirmatory low level signal) AND at least one low pressure ECCS pump running. There is no drywell pressure input to the initiation logic for ADS.

Since the licensee's ECCS-LOCA analysis (see section below titled, "ECCS Performance"), based on the proposed ADS capability, demonstrates that the system provides adequate core cooling, the NRC staff finds the evaluation acceptable, and agrees with the licensee's assessment that the ADS will continue to meet the NRC's acceptance criteria.

The EPU does not affect the protection provided for any of the ECCS features (HPCS, LPCS, LPCI and ADS) against the dynamic effects and missiles that might result from plant equipment failures.

ECCS Performance

The ECCS is designed to provide protection against postulated LOCAs caused by ruptures in the primary system piping. The ECCS performance under all LOCA conditions and the analysis models must satisfy the requirements of 10 CFR 50.46 and 10 CFR Part 50, Appendix K.

The following NRC staff approved codes were used for the LOCA analysis:

SAFER [References 28, 29, 30]

The SAFER code was used to calculate the long-term-thermal-hydraulic behavior of the coolant in the vessel during a LOCA. Some important parameters calculated by SAFER are vessel pressure, vessel water level, and ECCS flow rates. The SAFER code also calculates PCT and local maximum oxidation.

LAMB [Reference 35]

The LAMB code is used to analyze the short-term thermal-hydraulic behavior of the coolant in the vessel during a postulated LOCA. In particular, LAMB predicts the core flow, core inlet enthalpy, and core pressure during the initial phase of the LOCA event (i.e. the first 5 seconds).

GESTR-LOCA [References 28, 29, 30]

The GESTR-LOCA code is used to provide best-estimate predictions of the thermal performance of GE nuclear fuel rods experiencing variable power histories. For LOCA analysis, the GESTR code is used to initialize the fuel stored energy and fuel rod fission gas inventory at the onset of a postulated LOCA.

TASC [Reference 32]

The TASC code has been accepted for transient analysis and LOCA analysis. TASC is a functional replacement of the SCAT code. TASC is an improved version of the NRC-approved SCAT code, with the added capability to model advanced fuel features (partial length rods and new critical power correlation). TASC is a detailed model of an isolated fuel channel. It is used to predict the time to boiling transition for a large-break LOCA. This value is used in subsequent codes to turn off nucleate boiling heat transfer models and turn on transition boiling models. Because there is significant experience with GE's application of the SAFER/GESTR-LOCA methodology, and appreciable experience with the application of this methodology to EPU plants, the NRC staff's review focused on the results of the analysis, and how they may have changed for the EPU.

General Primer on GE's SAFER/GESTR-LOCA Results

The following paragraphs are excerpted from a tutorial on the SAFER/GESTR analysis process that was presented to the NRC staff in October, 2001 [Reference 29]. They are included here describe the differences in analysis results between the CLTP-analyzed core and the EPU core.

The SAFER/GESTR-LOCA code follows the approach delineated in SECY-83-472, "Emergency Core Coolant System Analysis Methods," published on November 17, 1983. The SAFER tool uses nominal models and correlations and relies on a break spectrum and single failure analyses using nominal assumptions.

The licensing basis PCT, however, is calculated using models required by 10 CFR Part 50 Appendix K. It is the sum of the nominal PCT and an adder. The adder is calculated as the square root of the sum of the squares of (1) the difference between the PCT calculated using Appendix K models and inputs and the nominal PCT, and (2) a plant variable uncertainty term. The plant variable uncertainty term accounts for uncertainty in parameters not specifically addressed by Appendix K. Plant variable uncertainties will include initial stored energy, internal fuel rod pressure, bypass leakage coefficients, ECCS initiation signals, and ADS actuation delay.

NMP2's LOCA Analysis Results

The NRC staff's evaluations of past EPU at BWRs have shown that the basic break spectrum is not affected by EPU, and that EPU is expected to have a small effect on the licensing basis PCT. Because the EPU implementation has only a small effect on PCT, the limiting single failure will not change due to EPU conditions.

The licensing basis PCT is based on the Appendix K PCT. The effect of EPU on the licensing basis PCT will be based on the delta PCT change from the large break and small break evaluation such that the licensing basis PCT is maximized. Use of the most limiting of the nominal or Appendix K PCT changes for the licensing basis PCT will ensure continued compliance with the requirements for the SAFER/GESTR LOCA application methodology as approved by the NRC.

The licensing basis PCT was determined based upon the calculated Appendix K PCT [[

]]. For the EPU, the GE14 Licensing Basis PCT for the large break DBA consisting of a maximum recirculation suction line break with a high pressure core spray-diesel generator failure was calculated to be ≤1540 °F at rated core flow, with transient cladding oxidation not exceeding 0.3 percent of the original cladding thickness, and hydrogen generation not exceeding 0.1 percent of the core-wide metal-water reaction.

Long-term cooling is assured when the core remains flooded to the jet pump top elevation and when a core spray system is operating.

In addition to the large-break LOCA analysis, the small-break LOCA response was analyzed and the limiting break was found to be the 0.07 ft^2 recirculation suction line break with the limiting single failure condition consisting of the high pressure core spray-diesel generator failure. The increased decay heat associated with EPU results in a longer ADS blowdown and a higher PCT for the small break LOCA. Previous analysis demonstrates that NMP2 is a small-break Appendix K PCT limited plant. The effect of EPU on the calculated small break PCT is acceptable as long as the impact of the results on the Licensing Basis PCT remains below the 10 CFR 50.46 limits. The current TS values for ECCS initiation were used for the analysis; no changes to these values were required for EPU. Plant-specific analyses demonstrate that there is sufficient ADS capacity, with six ADS valves in service and one out-of service, at EPU conditions, to remain below these limits. Key input parameters to the SAFER/GESTR LOCA evaluation model are provided in Table 2.8-3. Input parameters are selected as nominal or representative values. For Appendix K calculations, select inputs are chosen so as to set a bounding condition or to assure conservatism.

It should be mentioned that TRACE audit calculations were performed for the limiting large and small breaks identified above. TRACE calculation reproduced the results of the SAFER/GESTR analyses where TRACE was found to over-predict the licensing basis DBA large break by about 50 °F. Analysis of the 0.07 ft^2 recirculation suction line limiting small break was also performed where the PCT was under predicted by about 300 °F (1526 °F versus the TRACE result of 1200 °F). These calculations were performed based on pre-EPU conditions and verified the non-limiting nature of the PCTs compared to the 10 CFR 50.46 limit of 2220 °F. Because the PCTs for both the large- and small-break LOCA analyses were well below the 10 CFR 50.46 limit, the NRC staff chose not to undertake the effort to upgrade the TRACE model to perform these calculations at EPU conditions, particularly since there were no design changes or changes to the ECCS for the EPU submittal.

The NRC staff inquired about oxidation sources included in the licensee's LOCA analyses (RAI D13). The NRC staff inquired about both pre-existing oxidation, and about oxidation on both surfaces of the fuel cladding.

Regarding pre-existing oxidation, the licensee stated that the LOCA analyses consider only transient oxidation. However, GE14 fuel studies have concluded that (1) at the time of maximum stored energy, the pre-existing oxidation at NMP2 would be on the order of 1.19 percent, and (2) highly exposed bundles indicate oxidation levels as high as 3.53 percent. Since the predicted oxidation level at NMP2 is <9.0 percent, the results maintain significant margin to the 17 percent regulatory limit, even in consideration of the pre-existing oxidation. The NRC staff finds this clarification acceptable because there is still significant margin to the regulatory limits.

Regarding cladding inside oxidation, the licensee confirmed that the inside surface cladding is calculated as a part of the total transient cladding oxidation. Because the calculation considers both cladding surfaces, the NRC staff finds the licensee's response acceptable.

Based on the licensee's plant-specific LOCA analysis, and because the licensee will perform plant and cycle-specific evaluations of ECCS-LOCA performance for each fuel reload at the EPU conditions using approved methods, the NRC staff agrees with the licensee that the NMP2 ECCS-LOCA performance complies with 10 CFR 50.46 and Appendix K requirements.
The EPU analyses are acceptable for the following seven reasons:

1. The NRC staff evaluations of several requests for stretch power increase and EPU at BWRs have shown that the change of PCT for power uprates is not significant. The maximum increase in the PCT was small, and was well within the acceptance criteria of 10 CFR 50.46. Since there is only a small change in PCT, an EPU has a negligible effect on the adders used to determine the licensing basis PCT.

2. The ECCS performance characteristics and basic break spectrum response are largely unaffected by an EPU.

3. The limiting break sizes are well known and have been shown not to be a function of reactor power level.

4. The analyses assume the hot bundle continues to operate at the thermal limits (MCPR, MAPLGHR, and LHGR) which are not changed by the EPU.

5. The PCT for the limiting large-break LOCA is determined primarily by the hot bundle power, which is not expected to increase with power uprate.

6. The reload evaluation confirms that the MAPLHGR for each fuel type in the specific reload core is bounded by the MAPLHGR used in the ECCS-LOCA performance analysis.

7. Because the plant is MAPLHGR-limited, a detailed plant-specific analysis for the licensing basis PCT was performed.

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 reactor protection system and the ECCS will continue to ensure that the peak cladding temperature, total oxidation of the cladding, total hydrogen generation, and changes in core geometry, and long-term cooling, will remain within acceptable limits. Based on these considerations, the NRC staff finds the proposed EPU acceptable with respect to the ECCS-LOCA.

2.8.5.7 Anticipated Transients without Scram

Regulatory Evaluation

ATWS is defined as an AOO 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:

- Each BWR has an ARI system that is designed to perform its function in a reliable manner and be independent (from the existing reactor trip system) from sensor output to the final actuation device;

- Each BWR has a standby liquid control system (SLCS) with the capability of injecting into the reactor vessel a borated water solution with reactivity control at least equivalent to the control obtained by injecting 86 gpm of a 13 weight percent sodium pentaborate decahydrate solution at the natural boron-10 isotope abundance into a 251-inch inside diameter reactor vessel. The system initiation must be automatic;

- Each BWR has equipment to trip the reactor coolant recirculation pumps automatically under conditions indicative of an ATWS.

The NRC staff's review was conducted to ensure that:

1. The above requirements are met;

2. Sufficient margin is available in the setpoint for the SLCS pump discharge relief valve such that SLCS operability is not affected by the proposed EPU; and

3. Operator actions specified in the plant's Emergency Operating Procedures are consistent with the generic emergency procedure guidelines/severe accident guidelines (EPGs/SAGs), insofar as they apply to the plant design.

In addition, the NRC staff reviewed the licensee's ATWS analysis to ensure that:

1. The peak vessel bottom pressure is less than the ASME Service Level C limit of 1500 psig;

2. The peak clad temperature is within the 10 CFR 50.46 limit of 2200 °F;

3. The peak suppression pool temperature is less than the design limit; and

4. The peak containment pressure is less than the containment design pressure.

The NRC staff also evaluated the potential for thermal-hydraulic instability in conjunction with ATWS events in Section 2.8.3. This included a staff audit, conducted at NMP2 on October 28, 2009, to review the NMPNS ATWS procedures, and to witness three simulated ATWS events: turbine trip ATWS from MELLLA corner, MSIV isolation from MELLLA corner, and MSIV isolation from EPU conditions. Specific review criteria are provided in SRP Section 15.8 and additional guidance is provided in Matrix 8 of RS-001.

<u>Technical Evaluation</u>

The analysis of the ATWS is described in the NMP2 USAR Section 15.8, "Anticipated Transients without Scram." The USAR analyses verify that NMP2 is equipped with acceptable ATWS protection features for operation at power levels up to 3,467 MWth.

The licensee stated that NMP2 meets the ATWS requirements defined in 10 CFR 50.62 since NMP2 is equipped with (a) an Alternate Rod Insertion (ARI) system, (b) an SLCS with a boron injection capability that is equivalent to 86 gpm, and (c) an automatic Recirculation Pump Trip (RPT) logic (i.e. ATWS-RPT). In addition, a plant-specific ATWS analysis was performed, at EPU conditions, to confirm that (a) the peak vessel bottom pressure is less than ASME Service

Level C limit of 1500 psig, (b) the peak suppression pool temperature is less than 270 °F (Wetwell shell design temperature), and (c) the peak containment pressure is less than 45 psig (Drywell design pressure). Section 3.7 of [Reference 19] discusses the ATWS analysis methodology, and provides a generic evaluation of the following limiting ATWS events in terms of overpressure and suppression pool cooling: (a) Main Steam Isolation Valve Closure (MSIVC), (b) Pressure Regulator Failure - Open (PRFO), Loss of Offsite Power (LOOP), and (4) Inadvertent Opening of a Relief Valve (IORV).

The calculated PCTs for ATWS events using the methodology described in Section 3.7 of [Reference 19] have not exceeded 1600 °F. The EPU would not have a significant effect on the PCT or local clad oxidation, since the hot bundle, under EPU conditions, continues to be constrained by the pre-EPU operating thermal limits. The EPU will increase the average channel power and, thus, increase the flow through the hot channel (as the hot channel power remains the same). Therefore, the increased flow in the hot channel prevents the cladding temperature from increasing with the EPU.

Satisfying the 2200 °F PCT and the 17 percent local cladding oxidation limits of 10 CFR 50.46 demonstrate that a coolable core geometry is maintained. The PCT and local cladding oxidation criteria are generically addressed to demonstrate compliance with 10 CFR 50.46, the ATWS Rule for EPU.

Therefore, the NRC staff agrees that the generic evaluation shows compliance the ATWS acceptance criteria and NMP2 plant configuration meets the requirements of the ATWS Rule.

The licensee also performed plant-specific ATWS analyses for an equilibrium core at the EPU operating conditions to demonstrate that NMP2 continues to meet the ATWS acceptance criteria. Based on experience, only the limiting cases (MSIVC and PRFO) were analyzed.

Tables 2.8-5 and 2.8-6 of the PUSAR list the key ATWS analysis input parameters, and the results (i.e., peak vessel bottom pressure, peak suppression pool temperature, and peak containment pressure), respectively, for analyses performed at CLTP and EPU conditions. The values listed in these tables indicate the ATWS acceptance criteria are satisfied. Tables 2.8-7 and 2.8-8 of the PUSAR present the sequences of events for the MSIVC and PRFO ATWS analyses, respectively.

The NRC staff agrees that the plant-specific ATWS analyses meet the ATWS acceptance criteria.

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 EPU on ATWS. The NRC staff concludes that the licensee has demonstrated that ARI, SLCS, and recirculation pump trip systems have been installed and that they will continue to meet the requirements of 10 CFR 50.62 and the analysis acceptance criteria following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU 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 with the required subcritical margin for all normal and credible abnormal storage conditions. The NRC staff's review focused on the effect of EPU operations and 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.

TSs for NMP2 requires that the k-effective of the new fuel storage racks, fully flooded with unborated water, will not exceed 0.95 including an allowance for uncertainties as described in Section 9.1.1 of the USAR. The TSs also requires that the k-effective of the new storage racks will not exceed 0.98 with all but one of the non-combustible storage vaults covers in place with optimum moderation.

Technical Evaluation

Summary

In Table 2.8-10 of the PUSAR, the licensee reported a maximum k-effective value of less than 0.9 for normal conditions and less than 0.95 for abnormal conditions for a lattice average enrichment of 5.0 w percent U-235. Section 2.8.6.1 of the PUSAR, "New Fuel Storage," references Section 6.3.4 of NEDC-33004P-A, Revision 4 (CLTR) for the effect of power uprate on the new fuel storage racks. Section 6.3.4 of the CLTR provides brief statements on the effects of decay heat but does not provide any relevant information on fuel storage rack criticality. The NRC staff requested the licensee to provide additional technical justification for the reported new storage rack criticality limits.

By letter dated March 23, 2011 (ML110880300), the licensee submitted NEDC-33636P, "NMP2 Nuclear Station – Unit 2 Fuel Storage Criticality Safety Analysis of New Fuel Storage Racks – GE14." GEH analyzed the fresh GE14 fuel assemblies in the GEH Low-Density Fuel Storage (LDFS) racks using a design-basis assembly with a maximum in-core eigenvalue of 1.34 and a lattice average enrichment of 4.9 weight percent U-235. The acceptability of new fuel storage rack criticality is based on assumed fresh fuel condition. Therefore, the effects of EPU fuel depletion do not enter the new fuel storage analysis. The proposed EPU does not introduce any other fuel geometries. GEH calculated a maximum k-effective of 0.87697 for the worst credible abnormal conditions, which complies with the regulatory k-effective limit of 0.95. The licensee has proposed to include a maximum enrichment limit of 4.9 weight percent U-235 in the NMP2 TS for new fuel storage.

Based on the above and the additional discussion provided in this section of the SE, the NRC staff finds reasonable assurance that NMP2 will comply with the regulatory requirements.

Computational Methods and Validation

GEH used two computational methods in the criticality analysis for the new fuel storage rack: a lattice design code TGBLA06 to calculate the in-core k-infinity values and a Monte Carlo code MCNP-05P to obtain fuel storage rack k-effective values.

TGBLA06A is a two-dimensional lattice design computer program for BWR fuel bundle analysis. It assumes that a lattice is uniform and infinitely long along the axial direction and that the lattice geometry and material are reflecting with respect to the lattice boundary along the transverse directions. The NRC staff has previously reviewed and accepted the use of TGBLA06 for BWR core design calculations, as part of the approval of Amendment 26 of NEDE-24011-P-A, "GESTAR II – Implementing Improved GE Steady-State Methods" for operating BWRs. GEH applied a TGBLA06 cold eigenvalue uncertainty in the criticality analysis for the new fuel storage rack.

MCNP is a generally accepted code used to obtain the fuel storage rack k-effective values, and its use is acceptable provided it is properly validated. NEDC-33636P provided information describing the computational method validation. This information included a summary of the critical benchmark experiments and the area of applicability covered by the code validation. The analysis of the new fuel storage rack does not need to consider the depleted fuel composition. The validation also describes the determination of the bias and bias uncertainty. The NRC staff finds that the bias and bias uncertainty were determined from the validation database using an appropriate statistical treatment that is consistent with NUREG/CR-6698.

Based on the above, the NRC staff finds the two computational methods acceptable for use in the criticality safety analysis.

Fuel Assembly Design

The NRC staff verified that the criticality analysis used the appropriate fuel design data. Section 4 of NEDC-33636P describes fuel design-basis, which is the GE14 fuel design, and the fuel criticality model. GEH selected the design-basis lattice based on an analysis of GE14 fuel lattice types covering the limiting enrichments and gadolinium loadings at the beginning of life. The lattice corresponding to the highest in-rack k-effective was chosen as the design basis lattice. In addition, the appropriate fuel assembly data, including design tolerances, were used in the criticality analysis.

Storage Rack Design

The new fuel storage vault contains 27 rack modules which may contain up to 10 fresh fuel assemblies per rack module. The assemblies are maintained in the castings with a nominal center-to-center spacing within the rack module of 7 inches. The nominal center-to-center spacing between racks is 12.25 inches. A two-dimensional, infinite model has been defined to describe the new fuel rack storage system in MCNP-05P. The model contains no rack structural materials to limit the number of neutron absorptions by non-fuel components in the system.

Accident Condition

GEH calculated a maximum k-effective of the new fuel storage rack of 0.87697 for the worst credible abnormal condition, which meets the regulatory k-effective limit of 0.95. The maximum k-effective included allowances for appropriate manufacturing tolerances and other biases and uncertainties to establish a k-effective at a 95 percent probability, 95 percent confidence level.

Conclusion

The NRC staff has reviewed the licensee's analysis and dispositions related to the effect of EPU operation on new fuel storage facilities and concludes that the new fuel storage facilities will continue to meet the requirements of GDC-62 and plant-specific licensing basis following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the new fuel storage.

2.8.6.2 Spent Fuel Storage

Regulatory Evaluation

Nuclear reactor plants include storage facilities for the wet storage of spent fuel assemblies. The safety function of the spent fuel pool (SFP) and storage racks is to maintain the spent fuel assemblies in a safe and subcritical array during all credible storage conditions and to provide a safe means of loading the assemblies into shipping casks. The NRC staff's review covered the effect of the proposed EPU on the criticality analysis (e.g., reactivity of the spent fuel storage array and boraflex degradation or neutron poison efficacy).

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.

TSs for NMP2 requires that the k-effective of the spent fuel storage racks, fully flooded with unborated water, will not exceed 0.95 including an allowance for uncertainties as described in Section 9.1.1 of the USAR.

Technical Evaluation

Summary

The licensee reported a maximum k-effective value of 0.9413 for the spent fuel storage rack in Table 2.8-12 of the PUSAR. Section 2.8.6.2 of the PUSAR, "Spent Fuel Storage," references Section 6.3.4 of NEDC-33004P-A, Revision 4 (CLTR) for the effect of power uprate on the spent fuel storage racks. Section 6.3.4 of the CLTR does not provide relevant information on fuel storage rack criticality. The NRC staff requested the licensee to provide additional technical justification for the reported new storage rack criticality limits.

In a letter dated June 3, 2010, the licensee stated that GEH performed the criticality analysis in 2004 as described in Section 2.8.6 of the PUSAR. During the review, the NRC staff noted that the licensee referenced a spent fuel analysis performed by Holtec International in the NMP2

Updated Safety Analysis Report (USAR). In a letter dated July 30, 2010, licensee stated that the 2004 GEH analysis was based on an analysis that was performed for the transition from GE11 to GE14 fuel design in 2004; but this is not part of the NMP2 current licensing basis. In the same letter, the licensee stated that the Holtec criticality analysis referenced in Section 9.1.2 USAR is the current analysis of record. The NRC staff review was further complicated when the licensee subsequently informed the NRC staff in an email dated September 16, 2010 (ML103050187) that NMP2 has never submitted a criticality analysis to the NRC for review. The NRC staff review of an EPU application per Review Standard (RS)-001 assumes that an acceptable starting point (i.e., an analysis of record) is available. In this case, an acceptable analysis of record was not available. The NRC staff must understand the current licensing basis in order to accept the licensee's conclusion that the current analyses are bounding for EPU conditions.

Since the licensee claimed in the PUSAR that "EPU has no effect on the criticality analyses," it was necessary for the NRC staff to understand the current licensing basis in order to make a regulatory finding relative to post-EPU compliance with GDC 62. The NRC staff used the RAI process to request information necessary to complete the regulatory review. The licensee provided the supplemental information in letters dated February 19, 2010 (ML100550599), June 3, 2010 (ML101610168), July 30, 2010 (ML10217084), December 13, 2010 (ML103500364), and March 23, 2011 (ML110880300) to support its review.

Computational Methods and Validation

GEH used two computational methods in the criticality analysis. GEH lattice design code TGBLA06 was used to calculate burned fuel compositions and the in-core k-infinity values. The burned fuel compositions were then used in MCNP01A, the GEH proprietary version of MCNP4A, to obtain fuel storage rack k-effective values.

TGBLA06A is a two-dimensional lattice design computer program for BWR fuel bundle analysis. It assumes that a lattice is uniform and infinitely long along the axial direction and that the lattice geometry and material are reflecting with respect to the lattice boundary along the transverse directions. The NRC staff previously reviewed and accepted the use of TGBLA06 for BWR core depletion calculations, as part of the approval of Amendment 26 of NEDE-24011-P-A, "GESTAR II – Implementing Improved GE Steady-State Methods" for operating BWRs. The criticality analysis included an allowance for the TGBLA06 cold eigenvalue uncertainty.

MCNP is a generally accepted code used for criticality analyses, provided it is properly validated. The NRC staff considers the use of MCNP for the criticality analysis of spent fuel racks for NMP2 is similar to other applications, and therefore acceptable.

By letter dated July 30, 2010, the licensee provided information describing the computational method validation. Report 0000-0032-0998-R2, "MCNP01A Low Enriched UO_2 Pin Lattice in Water Critical Benchmark Evaluations Using ENDF/B-V Nuclear Cross-Section Data Revision 1," describes the critical experiments used in the validation study that form the validation basis for the computational method.

The validation report included a summary of the critical benchmark experiments and the area of applicability covered by the code validation. The validation set did not include critical experiments with fission product and actinide compositions similar to the burned fuel. To address the validation gaps associated with the extension of MCNP01A validation to include spent fuel bundles, an appropriate uncertainty was applied in the maximum k-effective as a bias, which provides conservatism. The NRC staff finds this acceptable.

The validation report describes the determination of the bias and bias uncertainty. The NRC staff finds that the bias and bias uncertainty were appropriately determined from the validation database, using a valid statistical analysis consistent with NUREG/CR-6698.

Based on the above, the NRC staff finds the two computational methods acceptable for use in the criticality safety analysis.

Fuel Assembly Design

The GEH analyzed the spent fuel storage racks with the GE14 fuel design. In a letter dated December 13, 2010, the licensee submitted the Holtec analysis and additional quantitative information showing that the spent fuel storage information submitted for the proposed EPU in conjunction with the most limiting GE14 lattice design, bounds all legacy fuel stored at NMP2.

The design basis lattice was determined from the TGBLA06A lattice depletion calculations accounting for the following depletion conditions/parameters: 1) uncontrolled state, 2) integral burnable poisons, 3) fuel temperature, 4) moderator temperature, 5) moderator density, 6) power density, and 7) void fractions. The lattice selection process included an analysis of eight lattices with variable lattice parameters such as exposure, enrichment, void fractions, number of Gd rods, and Gd enrichments. In a letter dated June 3, 2010, the licensee provided the core depletion parameters used to deplete the lattices as well as the range of lattice parameters covered by analysis.

GEH calculated several hundred in-core eigenvalues based on the range of lattice parameters. GEH then calculated the peak in-core eigenvalue state point for each of the eight lattices in the in-rack eigenvalue analysis. The lattice corresponding to the highest in-rack k-effective was chosen as the design basis lattice. The NRC staff finds that appropriate design basis lattice was selected for use in the criticality model.

Storage Rack Design

The NMP2 spent fuel storage relies on a neutron absorber (poison), Boral to maintain subcriticality. In response to an NRC staff RAI, the licensee confirmed that the NMP2 SFP contains no Boraflex racks which are known to degrade. In addition, the licensee clarified that while Boraflex racks are still in use in the Nine Mile Point Unit 1 (NMP1) SFP, the NMP1 SFP and NMP2 SFP are in separate buildings with no fuel transfer capability between the two SFPs.

Technical Evaluation

The licensee utilizes Holtec Boral high density neutron absorber material in their spent fuel pool racks. The licensee stated that NMP2 added 10 new Holtec Boral spent fuel storage racks as part of the phase I re-rack in 2001. Afterward, in 2007, the licensee performed the phase II re-rack, which replaced 16 original Boraflex spent fuel storage racks with Boral racks. The spent fuel pool rack design allows venting through small openings at the corners of the Boral sheathing pockets.

The licensee stated that the Boral monitoring program utilizes three coupon trees with ten coupons on each tree as part of the coupon program. One coupon tree contain sample Boral material (i.e. same lot of material) contained in the spent fuel pool racks installed in 2001 and two coupon trees contain samples of the Boral installed in 2007. The licensee reported that all three coupon trees were installed in 2007. The licensee indicated that when the coupons trees are removed for inspection, the coupons are evaluated as follows:

1. *Visual appearance (deterioration, corrosion, cracks, and dents);*
2. *Dimensional measurements;*
3. *Specific gravity and density measurements; and*
4. *Boron-10 areal density measurements (via neutron attenuation testing).*

The neutron attenuation measurements are performed to verify the continued presence of Boron-10 areal density in the coupons and thickness measurements are performed to determine the extent of swelling. The licensee stated that the acceptance criteria for the neutron attenuation and thickness measurements on the coupons are the following:

- *A decrease of no more than 5 percent in Boron-10 content, as determined by neutron attenuation. (This is tantamount to a requirement for no loss in boron within the accuracy of the measurement.)*
- *An increase in thickness at any point should not exceed 10 percent of the initial thickness at that point.*

The licensee stated that the coupon tree that is representative of the phase I Boral spent fuel pool racks installed in 2007 is scheduled to be removed in 2012 for coupon inspection. In addition, the schedule of coupon inspection for these representative coupons is based on a 10-year frequency. The schedule will be re-evaluated if degradation of the Boral material is identified at NMP2 or industry operating experience warrants increasing the frequency of inspection. The NRC staff finds the inspection frequency and acceptance criteria appropriate for the Boral coupon program.

The licensee stated that the locations of the coupon trees are not static, but rather the locations change as a result of spent fuel pool optimization. The coupon trees are placed in locations where freshly-discharged fuel assemblies are loaded. The licensee further indicated that the freshly-discharged fuel is loaded around the coupon to the greatest extent possible so that the coupons receive maximum exposure. The NRC staff finds this acceptable because the coupons will be bounding of the Boral spent fuel pool rack that experiences the greatest neutron exposure. In an email dated May 12, 2011, the NRC staff requested the licensee to provide supplemental information on the surveillance approach and testing for the 10 Boral spent fuel racks installed in 2001 at NMP2.

In its response dated June 13, 2011, the licensee indicated that in-situ neutron attenuation testing will be periodically conducted on the 10 phase I Boral spent fuel pool racks installed in 2001. Although one of the three coupon trees installed in 2007 contains the same lot of Boral as the Boral racks installed in 2001, the licensee indicated that these coupons will not be used to monitor the Boron-10 areal density. Instead, in-situ Boron-10 Areal Density Gauge for Evaluating Racks (BADGER) testing will be performed to monitor the Boron-10 areal density for the phase I racks installed in 2001, beginning in 2012. The schedule of in-situ testing of the racks is based on a 10-year frequency. The schedule will be re-evaluated if degradation of the Boral material is identified at NMP2 or industry operating experience warrants increasing the frequency of testing. The NRC staff finds in-situ testing at a 10-year frequency acceptable because degradation of Boral will be detected and mitigated before any degradation effects will challenge the criticality analysis of record. In an email dated June 23, 2011, the NRC staff requested the licensee to provide supplemental information on the acceptance criteria for the in-situ BADGER testing, including the corrective actions taken if the acceptance criterion is not met.

In its response dated July 15, 2011, the licensee stated that BADGER testing, for the phase I Boral spent fuel racks installed at NMP2 in 2001, will confirm that the minimum Boron-10 areal density assumed in the spent fuel pool criticality analyses is met. Furthermore, the licensee stated that the spent fuel pool criticality analyses assume a minimum Boron-10 areal density of 20 milligrams Boron-10 per square centimeter (20 mg Boron-10/cm^2). That is, the acceptance criterion for the BADGER tests will be to ensure a Boron-10 areal density $\geq$ 20 mg Boron-10/cm^2.

If the acceptance criterion is not met, the following actions will be taken:

1. *The condition would be entered into the site's Corrective Action Program*
2. *Administrative controls would be implemented to ensure that fuel is not stored within the impacted location(s) until the condition is resolved.*
3. *An evaluation would be conducted to determine if more frequent and expanded surveillance of the spent fuel storage racks is needed.*

The NRC staff finds the acceptance criteria and corrective actions acceptable because they will ensure that the Boral spent fuel racks will continue to meet its intended function in the criticality analysis of record.

After reviewing the effects of the EPU on the Boral neutron absorber material and the adequacy of the Boral monitoring program, the NRC staff finds the program acceptable because it allows for detection of degradation in the Boral spent fuel pool racks. This is accomplished by detection and monitoring of degradation in the Boral coupons for the racks installed in 2007. The Boral monitoring program tests selected coupons at a 10-year frequency, exposes the coupons to a similar environment to that of the actual Boral in spent fuel pool, and maximizes the amount of exposure the coupon trees receive while in the spent fuel pool. Inspection of the Boral coupons, which are indicative of the Boral in the spent fuel pool, is an acceptable means to monitor for loss of material and reduction of neutron absorber capacity. In addition, the performance of in-situ testing of the spent fuel pool racks installed in 2001 for the Boron-10 areal density is acceptable because it also allows for detection of degradation (i.e., reduction of neutron-absorbing capacity and loss of material) in the Boral spent fuel pool racks.

The acceptance criteria were determined to be acceptable because it will ensure that the structure and component intended function(s) are maintained under EPU spent fuel pool conditions. Furthermore, monitoring the physical condition as part of the acceptance criteria, of the neutron-absorbing material, such as geometric changes in the material (formation of blisters, pits and bulges) and decreased Boron-10 areal density is acceptable because any degradation will be detected and mitigated before any degradation effects will challenge the criticality analysis of record.

Conclusion

The NRC staff has reviewed the licensee's evaluation of the effects of the proposed EPU on the Boral neutron absorber material used in the NMP2 and concludes that the licensee has adequately addressed the impact of the EPU on the Boral spent fuel pool racks. The NRC staff further concludes that the licensee has demonstrated that the Boral monitoring program will continue to be acceptable in detecting degradation of Boral material and will continue to meet the requirements of 10 CFR 50.68(b)(4), SRP 9.1.2, and GDC 62, following implementation of the proposed EPU. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the Boral monitoring program.

Uncertainty Analysis

Table 2.8-12 of the PUSAR shows how the licensee determined the maximum in-rack k-effective including biases and uncertainties. Table 2.8-12 showed the statistical summation of the uncertainties but not the individual uncertainty components. In a letter dated July 30, 2010, the licensee provided the uncertainty components included in the analysis and showed a maximum k-effective of 0.9492. The maximum k-effective included allowances for depletion uncertainty and code validation gaps as biases. While the maximum k-effective reported in the letter dated July 30, 2010, provided a margin of only 80 pcm[32] to the licensing limit of 0.95, the application of these uncertainty terms as biases provides about 600 pcm of conservatism in the analysis. The NRC staff noted that some uncertainty components were not included. In addition, the effect of pool temperature was included as an uncertainty when it should be applied as a bias. However, the NRC staff finds these effects would be reasonably offset by the noted conservatism. Therefore, the NRC staff finds the licensee's uncertainty analysis acceptable.

Accident Conditions

In a letter dated June 3, 2010, the licensee considered the following accidents in the criticality analysis.

1. lateral movement of a rack module,

2. misplacement of a fuel assembly, and

3. dropped assembly.

The licensee stated that the maximum k-effective is based on an infinite array of storage cells, loaded with the most reactive lattice analyzed, and did not incorporate any radial or axial leakage. Therefore, the analyzed configuration bounded the above accident conditions. In a letter dated July 3, 2010, the licensee stated that the spent fuel storage racks at NMP2 have neutron poison (Boral) panels on the periphery. Due to the presence of external Boral sheathing in the NMP2 storage racks, the model used bounds the rack-sliding configuration.

[32] pcm = percent millirho or $10^{-5}\ \Delta\rho$

Based on the above, the NRC staff finds the scope of the accident conditions considered acceptable.

Technical Specifications

In a letter dated March 23, 2011, the licensee proposed the following additional requirements in the NMP2 TS.

1. Maximum allowable U-235 enrichment, and

2. Standard cold core geometry k-infinity.

The NRC staff finds that the proposed changes are in accordance with 10 CFR 50.36, hence acceptable.

Conclusion

The NRC staff has reviewed the licensee's generic and plant-specific assessment related to the effects of the proposed EPU on the spent fuel storage capability and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the spent fuel criticality analyses. In addition, the licensee will perform plant-specific reload analyses to confirm that the SFP design will continue to ensure an acceptable degree of subcriticality following implementation of the proposed EPU.

In consideration of the information discussed above, the NRC staff finds reasonable assurance that fuel will comply with the regulatory requirements under all normal and credible abnormal conditions following implementation of the proposed EPU, and is acceptable to the staff.

2.8.7 Additional Review Area – Methods Evaluation

2.8.7.1 Topics from GEH Licensing TR NEDC-33173P

Regulatory Evaluation

The analyses supporting safe operation at EPU conditions are performed using NRC-approved licensing methodology, analytical methods and codes. In general, the accuracy of the analytical methods and codes are assessed and benchmarked against measurement data, comparisons to actual nuclear plant test data and research reactor measurement data. The uncertainties and biases associated with specific correlations simulating physical phenomena, with key parameters or with integral code calculations modeling a design bases event are determined. The identified uncertainties associated with the analytical methods, the measured quantities used to simulate the core conditions and the manufacturing tolerances (e.g., fuel manufacturing tolerances) are accounted for in the analyses. NRC-approved licensing methodology, TRs and codes specify the applicability ranges.

The generic LTR covering specific analytical methods or code system quantify the accuracy of the methods or the code used. The SE report approving the TR includes limitations that delineate the conditions that warrant specific actions, such as obtaining measurement data or when new NRC approval is required. In general, the use of NRC-approved analytical methods is contingent upon application of these methods and codes within the ranges for which the data was provided and against which the methods were evaluated. Thus, in general, the plant-specific application does not entail review of the NRC-approved analytical methods and codes.

The NRC staff review of the referenced interim methods LTR (IMLTR) NEDC-33173P [Reference 20] was to verify the following:

- The analytical methods and codes used to perform the design-bases safety analyses will be applied within the applicable NRC-approved validation ranges. The calculation and measurement uncertainties applied to the thermal limit calculations and the models simulating physical phenomena will remain valid for the predicted neutronic and thermal hydraulic core and fuel conditions during steady-state, transient, and accident conditions. The qualification database supporting analytical models simulating physical phenomena remains valid and applicable to the conditions under which it is applied, including those models and key parameters in which specific uncertainties are not applied.

- If the NRC-approved analytical methods and codes are extended outside the applicability ranges, the extension of the specific models are demonstrated to be acceptable or additional margins are applied to the affected downstream safety analyses until such time the supporting qualification data is extended.

The NRC staff SER for NEDC-33173P, "Applicability of GE Methods to Expanded Operating Domains," dated January 17, 2008, specifies the limitations that apply to NEDC-33173P [Reference 21].

<u>Technical Evaluation</u>

Nine Mile Point Nuclear Station (NMPNS) referenced NEDC-33173P to justify application of GE-Hitachi (GEH) methods to NMP2 EPU. Each condition specified in the NRC staff SE for NEDC-33173P was evaluated for acceptability for NMP2 EPU by NMPNS in Appendix A of the PUSAR [1]. The staff review of these conditions is discussed below.

2.8.7.1.1 <u>Condition 1: TGBLA/PANAC Version</u>

IMLTR SE Condition

The neutronic methods used to simulate the reactor core response and that feed into the downstream safety analyses supporting operation at EPU/MELLLA+ will apply TGBLA06/PANAC11 or later NRC-approved version of the neutronic method.

PUSAR Disposition

Appendix A of the NMP2 PUSAR states that TGBLA06/PANAC11 methods are used in the safety analysis [Reference 1]. Section 2.8.1 of the PUSAR confirms that the NMP2 EPU LAR is based on GE14 fuel. The staff has approved the IMLTR for GEH/GNF fuel designs up to GNF2.[33]

[33] The final supplemental IMLTR safety evaluation report was received on December 28, 2010 for NEDC-33173P, Supplement 3 (GNF2 applicability). The accepted version was published in July 2011.

As part of its review of the IMLTR, the staff reviewed modifications to the TGBLA06 code that improve the accuracy in the nodal depletion calculations at high void fraction. In its review of the ESBWR [Reference 34], a similar power uprate LAR [Reference 35], and during its review of TRACG04; the staff reviewed the results of code-to-code comparisons that indicate that the modifications made to TGBLA06 do not significantly affect the results of lattice calculations performed for GE14 fuel lattices specifically. Therefore, without further clarification of the TGBLA06 code version used to perform the analysis, the staff is reasonably assured in the adequacy of the calculations performed for GE14 fuel. Therefore, the staff finds that NMPNS has adequately met the IMLTR condition.

2.8.7.1.2 Condition 2: 3D MONICORE

IMLTR SE Condition

For EPU/MELLLA+ applications, relying on TGBLA04/PANAC10 methods, the bundle RMS difference uncertainty will be established from plant-specific core-tracking data, based on TGBLA04/PANAC10. The use of plant-specific trendline based on the neutronic method employed will capture the actual bundle power uncertainty of the core monitoring system.

PUSAR Disposition

Appendix A of the NMP2 PUSAR states that the NMP2 3D MONICORE core monitoring system is based on TGBLA06/PANAC11 methods. Therefore, this condition is not applicable to NMP2. Therefore, the NRC staff finds that the disposition of the condition is acceptable.

2.8.7.1.3 Condition 3: Power to Flow Ratio

IMLTR SE Condition

Plant-specific EPU and expanded operating domain applications will confirm that the core thermal power to core flow ratio will not exceed 50 MWth/Mlbm/hr at any statepoint in the allowed operating domain. For plants that exceed the power-to-flow value of 50 MWth/Mlbm/hr, the application will provide power distribution assessment to establish that neutronic methods axial and nodal power distribution uncertainties have not increased.

PUSAR Disposition

Section 2.8.2.5.2 of the PUSAR states that the power to flow ratio is less than 50 MWth/Mlbm/hr [Reference 1]. The staff confirmed that the power to flow ratio at the highest thermal power at the minimum flow point (100 percent EPU power / 99 percent rated core flow) is less than 50 MWth/Mlbm/hr based on the plant information provided in the PUSAR. The PUSAR states that the disposition of the condition is consistent with the guidance provided in MFN 08-693 regarding the power to flow ratio [Reference 1] and [Reference 22]. The power/flow operating map does not change from cycle to cycle, therefore, the staff finds that the power to flow ratio is within the limit imposed by Condition 3. As the power to flow ratio remains below 50 MWth/Mlbm/hr at the minimum flow point at the highest power level, the staff finds that this condition is met and is, therefore, acceptable.

2.8.7.1.4 Condition 4: SLMCPR 1

IMLTR SE Condition

For EPU operation, a 0.02 value shall be added to the cycle-specific SLMCPR value. This adder is applicable to SLO, which is derived from the dual loop SLMCPR value.

PUSAR Disposition

Sections 2.8.2.3.1 and 2.8.5.8 confirm that a 0.02 adder is applied to the cycle-specific SLMCPR as part of the reload licensing analysis (RLA). This adder is applied consistent with the NRC staff's condition, and therefore, the PUSAR disposition is acceptable.

2.8.7.1.5 Condition 5: SLMCPR 2

IMLTR SE Condition

For operation at MELLLA+, including operation at the EPU power levels at the achievable core flow statepoint, a 0.03 value shall be added to the cycle-specific SLMCPR value.

PUSAR Disposition

Appendix A of the PUSAR states that the current LAR is for EPU operation and approval for operation in the MELLLA+ domain is not currently sought [Reference 1]. Therefore, Condition 5 is not applicable to the NMP2 EPU application.

2.8.7.1.6 Condition 6: R-factor

IMLTR SE Condition

The plant-specific R-factor calculation at a bundle level will be consistent with lattice axial void conditions expected for the hot channel operating state. The plant-specific EPU/MELLLA+ application will confirm that the R-factor calculation is consistent with the hot channel axial void conditions.

PUSAR Disposition

Section 2.8.2.5.3 of the PUSAR provides the basis for the R-factor calculation [Reference 1]. The IMLTR condition requires that the R-factor be calculated using representative axial void conditions based on the core loading. Figure 2.8-19 of the PUSAR provides the distribution of bundle average void fractions for the low CPR (potentially limiting) bundles based on a reference GE14 fueled core. The distribution of these bundle void fractions demonstrates that an average bundle void fraction of 50 percent is reasonable to characterize the potentially limiting bundles. Therefore, the NRC staff finds that the PUSAR disposition of the condition is acceptable.

2.8.7.1.7 Condition 7: ECCS-LOCA 1

IMLTR SE Condition

For applications requesting implementation of EPU or expanded operating domains, including MELLLA+, the small- and large-break ECCS-LOCA analyses will include top-peaked and midpeaked power shape in establishing the MAPLHGR and determining the PCT. This limitation is applicable to both the licensing bases PCT and the upper bound PCT. The plant-specific applications will report the limiting small- and large-break licensing basis and upper bound PCTs.

PUSAR Disposition

Condition 7 of the NRC SE for the IMLTR requires that the ECCS-LOCA performance analyses consider both top-peaked and mid-peaked power distributions. Section 2.8.7.6.2 of the PUSAR provides the results of the ECCS-LOCA analyses [Reference 1]. Table 2.8-4 of the PUSAR provides the results of the limiting Appendix K small- and large-break LOCA analyses as well as the limiting nominal small- and large-break LOCA analyses. The table provides the results calculated for both mid-peaked and top-peaked power shapes. On this basis, the NRC staff finds that the analysis is consistent with the NRC staff's condition. As both results are provided the NRC staff finds that Table 2.8-14 provides an adequate basis to determine the limiting axial power shape for ECCS-LOCA evaluations. Therefore, the NRC staff finds the PUSAR disposition acceptable.

2.8.7.1.8 Condition 8: ECCS-LOCA 2

IMLTR SE Condition

The ECCS-LOCA will be performed for all statepoints in the upper boundary of the expanded operating domain, including the minimum core flow statepoints, the transition statepoint as defined in [Reference 21] and the 55 percent core flow statepoint. The plant-specific application will report the limiting ECCS-LOCA results as well as the rated power and flow results. The Supplemental Reload Licensing Report (SRLR) will include both the limiting statepoint ECCS-LOCA results and the rated conditions ECCS-LOCA results.

PUSAR Disposition

Condition 8 of the NRC SER for the IMLTR is applicable to MELLLA+ operation. As the current LAR does not request approval to operate in the MELLLA+ domain this condition is not applicable to NMP2.

2.8.7.1.9 Condition 9: Transient LHGR 1

IMLTR SE Condition

Plant-specific EPU and MELLLA+ applications will demonstrate and document that during normal operation and core-wide AOOs, the T-M acceptance criteria as specified in Amendment 22 to GESTAR II will be met. Specifically, during an AOO, the licensing application will demonstrate that the: (1) loss of fuel rod mechanical integrity will not occur due to fuel melting and (2) loss of fuel rod mechanical integrity will not occur due to pellet–cladding mechanical interaction. The plant-specific application will demonstrate that the T-M acceptance criteria are met for the both the uranium oxide (UO_2) and the limiting gadolinium oxide (GdO_2) rods.

PUSAR Disposition

Section 2.8.5.8 of the PUSAR documents the results of the AOO T-M analysis [Reference 1]. The PUSAR analysis considered the potentially limiting AOO pressurization transients, including equipment out-of-service considerations. The results considered both UO_2 and GdO_2 fuel rods. The limiting results were provided for margin to the fuel centerline and cladding plastic strain criteria. Therefore, the NRC staff finds that Condition 9 has been acceptably met.

2.8.7.1.10 Condition 10: Transient LHGR 2

IMLTR SE Condition

Each EPU and MELLLA+ fuel reload will document the calculation results of the analyses demonstrating compliance to transient T-M acceptance criteria. The plant T-M response will be provided with the SRLR or COLR, or it will be reported directly to the NRC as an attachment to the SRLR or COLR.

PUSAR Disposition

Section 2.8.5.8 of the PUSAR states that acceptable fuel rod thermal-mechanical responses will be documented in the SRLR or COLR consistent with Condition 10. Therefore, the NRC staff finds that Condition 10 has been acceptably met.

2.8.7.1.11 Condition 11: Transient LHGR 3

IMLTR SE Condition

To account for the impact of the void history bias, plant-specific EPU and MELLLA+ applications using either TRACG or ODYN will demonstrate an equivalent to 10 percent margin to the fuel centerline melt and the 1 percent cladding circumferential plastic strain acceptance criteria due to pellet-cladding mechanical interaction for all of limiting AOO transient events, including equipment out-of-service. Limiting transients in this case, refers to transients where the void reactivity coefficient plays a significant role (such as pressurization events). If the void history bias is incorporated into the transient model within the code, then the additional 10 percent margin to the fuel centerline melt and the 1 percent cladding circumferential plastic strain are no longer required.

PUSAR Disposition

Section 2.8.5.8 of the PUSAR provides the minimum calculated margin to the fuel centerline melt and cladding plastic strain criteria of 21.2 percent and 20.0 percent, respectively. These analyses demonstrate greater margin than the 10 percent required by Condition 11. Therefore, the NRC staff finds that Condition 11 has been acceptably met.

2.8.7.1.12 Condition 12: LHGR and Exposure Qualification

IMLTR SE Condition

In MFN 06-481, GE committed to submit plenum fission gas and fuel exposure gamma scans as part of the revision to the T-M licensing process. The conclusions of the plenum fission gas and fuel exposure gamma scans of GE 10x10 fuel designs as operated will be submitted for NRC staff review and approval. This revision will be accomplished through Amendment to GESTAR II or in a T-M licensing LTR. PRIME (a newly developed T-M code) has been submitted to the NRC staff for review. Once the PRIME LTR and its application are approved, future license applications for EPU and MELLLA+ referencing LTR NEDC-33173P must utilize the PRIME T-M methods.

PUSAR Disposition

At the time of the LAR submittal, the PRIME LTR was under review by the NRC staff. Therefore, the NMP2 EPU application is based on the GSTRM T-M methodology. The NRC staff finds that this is consistent with the condition based on the state of its review of the PRIME T-M methods.

2.8.7.1.13 Condition 13: Application of 10 Weight Percent Gadolinia

IMLTR SE Condition

Before applying 10 weight percent Gd (gadolinia loaded as burnable absorber) to licensing applications, including EPU and expanded operating domain, the NRC staff needs to review and approve the T-M LTR demonstrating that the T-M acceptance criteria specified in GESTAR II and Amendment 22 to GESTAR II can be met for steady-state and transient conditions. Specifically, the T-M application must demonstrate that the T-M acceptance criteria can be met for TOP and MOP conditions that bounds the response of plants operating at EPU and expanded operating domains at the most limiting statepoints, considering the operating flexibilities (e.g., equipment out-of-service). Before the use of 10 weight percent Gd for modern fuel designs, NRC must review and approve TGBLA06 qualification submittal. Where a fuel design refers to a design with Gd-bearing rods adjacent to vanished or water rods, the submittal should include specific information regarding acceptance criteria for the qualification and address any downstream impacts in terms of the safety analysis. The 10 weight percent Gd qualifications submittal can supplement this report.

PUSAR Disposition

Section 2.8.2.5.5 of the PUSAR states that the NMP2 EPU bundle design will utilize less than 10 w/o gadolinia in the fuel [Reference 1]. Therefore, the NRC staff finds that the LAR is consistent with this condition. Therefore, the NRC staff finds the disposition acceptable.

2.8.7.1.14 Condition 14: Part 21 Evaluation of GSTRM Fuel Temperature Calculation

IMLTR SE Condition

Any conclusions drawn from the NRC staff evaluation of the GE's Part 21 Report, "Adequacy of GE Thermal-Mechanical Methodology, GSTRM (January 27, 2007) will be applicable to the GSTRM T-M assessment of this SE for future license application. The NRC staff determined that until such time that GE benchmarks the GSTRM methodology, the $P_{critical}$ acceptance criteria will be reduced by 350 psi. This adjusted $P_{critical}$ must be used to verify that the LHGR limit for the current fuel designs remains applicable with burnup.

PUSAR Disposition

Appendix A of the PUSAR states that the Appendix F IMLTR SE critical pressure penalty of 350 psi is applied to the GE14 T-M analysis in the determination of the thermal-mechanical operating limits (TMOLs) [Reference 1]. In accordance with the General Electric Standard Application for Reactor Fuel (GESTAR II) process [Reference 37], GNF revised the GE14 GESTAR II Compliance Report [Reference 23] to incorporate an updated TMOL. The updated TMOL addresses the 350 psi penalty for plants referencing the IMLTR. The NRC staff conducted an audit of the revised GESTAR II compliance documentation [Reference 38]. The NRC staff found that the revised TMOL was acceptable. Therefore, the PUSAR TMOL analyses are consistent with Condition 14, and the NRC staff finds that the condition has been acceptably met.

2.8.7.1.15 Condition 15: Void Reactivity 1

IMLTR SE Condition

The void reactivity coefficient bias and uncertainties in TRACG for EPU and MELLLA+ must be representative of the lattice designs of the fuel loaded in the core.

PUSAR Disposition

Appendix A of the PUSAR states that TRACG methods are not utilized for AOO or ATWS analyses; however, TRACG04 calculations are performed for the thermal-hydraulic stability analysis for the NMP2 EPU [Reference 1]. The PUSAR states that the void reactivity coefficient bias and uncertainties used in the stability analysis is representative of the lattice designs of the fuel loaded in the NMP2 reference core.

The NRC staff has previously reviewed the TRACG04 void reactivity coefficient bias and uncertainties model during its review of the Migration LTR [Reference 36] and [Reference 39]. The staff review considered the improved void reactivity coefficient biases and uncertainties model for modern 10X10 fuel lattices representative of GE14 fuel. In its review, the staff found that the improved model was acceptable for application to EPU and MELLLA+ AOO and ATWS overpressure analyses [Reference 36].

The NRC staff has previously reviewed the application of TRACG04 to perform stability calculations for the ESBWR [Reference 40]. In its review of the TRACG04 stability analysis methodology for the ESBWR the staff deferred the review of the adequacy of the nuclear data to its review of NEDC-33239P, "GE14 for ESBWR Nuclear Design Report."

As part of its review of NEDC-33239P, the NRC staff reviewed the applicability of PANAC11 generated nuclear data for use in TRACG04 transient calculations as part of its review of the application of TRACG04 to the ESBWR. As part of this review, the NRC staff issued RAI 21.6-111 and RAI 7.2-71. In response to ESBWR RAI 7.2-71, GEH states that the use of PANAC11 in ESBWR reload transient analyses (including AOO, stability, or ATWS) requires that TRACG utilize the void reactivity coefficient correction model described in the response to RAI 21.6-111 from the ESBWR docket [Reference 41]. The response to RAI 21.6-111 [Reference 42] is essentially identical to the RAI 30 response for the Migration LTR [Reference 43] that describes the implementation of the improved void reactivity coefficient biases and uncertainties model. The staff has previously reviewed the improved void reactivity coefficient biases and uncertainties for application to TRACG04 for transient analysis, and in the case of the ESBWR, specifically to analyze stability [Reference 36] and [Reference 44].

TRACG02 has previously been approved to perform stability analyses, particularly the calculation of the DIVOM slope. In 2006, NMPNS performed a 50.59 evaluation to migrate to the TRACG04 methodology for the calculation of the DIVOM slope for NMP2. In its review of the Migration LTR, the staff determined that the thermal-hydraulic models were largely consistent between the two versions (most differences were for models related to LOCA phenomena). The staff has inspected the implementation of TRACG04 for stability analyses at various BWR plants and concluded that the evaluation provided in GE-NE-0000-0052-5590, "TRACG04 DIVOM 10 CFR 50.59 Evaluation Basis," April 2006, shows that the results are essentially the same for TRACG02 as TRACG04 [45] and [Reference 46]. Therefore the staff agrees that the results of the DIVOM slope calculation performed using either version of TRACG are essentially the same.

Consistently, the NRC staff has required that the improved model be utilized in the transient calculations performed using TRACG04. On these bases, the staff finds that the use of the approved, improved void reactivity coefficient biases and uncertainties is appropriate for the NMP2 TRACG04 DIVOM analyses. Therefore, the staff finds that the limited usage of TRACG04 in the NMP2 safety analysis is consistent with the IMLTR SE Condition 15.

2.8.7.1.16 Condition 16: Void Reactivity 2

IMLTR SE Condition

TRACG internally models the response surface for the void coefficient biases and uncertainties for known dependencies due to the relative moderator density and exposure on nodal basis. Therefore, the void history bias determined through the methods review can be incorporated into the response surface "known" bias or through changes in lattice physics/core simulator methods for establishing the instantaneous cross-sections. Including the bias in the calculations negates the need for ensuring that plant-specific applications show sufficient margin. For application of TRACG to EPU and MELLLA+ applications, the TRACG methodology must incorporate the void history bias. The manner in which this void history bias has been accounted for was established by the NRC staff SE approving NEDE-32906P, Supplement 3 [Reference 36].

PUSAR Disposition

Appendix A of the PUSAR states that TRACG methods are not utilized for AOO or ATWS analyses; however, TRACG04 calculations are performed for the thermal-hydraulic stability analysis for the NMP2 EPU [Reference 1]. As discussed in Section 2.8.7.1.2.15 of this SE, the NMP2 stability analyses are performed using the void reactivity coefficient bias and uncertainties that account for the void history biases. This correction model is the same model that was reviewed by the staff during its review of the Migration LTR [Reference 39]. The staff, therefore, finds that the NMP2 EPU LAR is consistent with Condition 16 of the IMLTR SE.

2.8.7.1.17 Condition 17: Steady State Five Percent Bypass Voiding

IMLTR SE Condition

The instrumentation specification design bases limit the presence of bypass voiding to 5 percent (LRPM levels). Limiting the bypass voiding to less than 5 percent for long-term steady operation ensures that instrumentation is operated within the specification. For EPU and MELLLA+ operation, the bypass voiding will be evaluated on a cycle-specific basis to confirm that the void fraction remains below 5 percent at all LPRM levels when operating at steady-state conditions within the MELLLA+ upper boundary. The highest calculated bypass voiding at any LPRM level will be provided with the plant-specific SRLR.

PUSAR Disposition

Section 2.8.2.5.1 of the PUSAR provides a demonstration analysis of the steady-state bypass void fraction at the LPRM Level D [Reference 1]. The analysis is performed using a conservative bounding ISCOR calculation that limits cross flow and maximizes the radial peaking factor for a four bundle set. The results of the calculation indicate that, for the reference configuration, the bypass void fraction is below 5 percent (at the minimum flow point for the highest reactor power level the ISCOR calculated void fraction was less than 3 percent).

The ISCOR calculation is performed on a cycle-specific basis as part of the RLA. The PUSAR states that alternatively less conservative ISCOR calculation may be performed so long as the ISCOR input assumption remain conservative relative to detailed TRACG calculations. The staff finds either approach acceptable. The PUSAR states that the cycle-specific analysis will be documented in the cycle-specific SRLR. Additionally, the results of the calculations performed for the reference core demonstrate that with conservative analysis assumptions that the steady-state bypass void fraction at the LPRM Level D location is less than 5 percent. On these bases, the staff finds that the NMP2 EPU LAR is consistent with Condition 17, and is therefore acceptable.

2.8.7.1.18 Condition 18: Stability Setpoints Adjustment

IMLTR SE Condition

The NRC staff concludes that the presence of bypass voiding at the low-flow conditions where instabilities are likely, can result in calibration errors of less than 5 percent for OPRM cells and less than 2 percent for APRM signals. These calibration errors must be accounted for while determining the setpoints for any detect and suppress long-term methodology. The calibration values for the different long-term solutions are specified in the associated sections of the SE for the IMLTR, discussing the stability methodology.

PUSAR Disposition

Section 2.8.3.1 of the PUSAR provides the disposition of IMLTR SE Condition 18 [1]. NMP2 relies on the BWR Owners' Group long-term stability solution Option III. Option III is predicated on a detect and suppress strategy and utilizes an oscillation power range monitor (OPRM) trip. Section 2.8.3.1 of the PUSAR states that the OPRM setpoint is calculated according to an assumed 5 percent calibration error. The staff finds that this is consistent with Condition 18.

The PUSAR states that the APRM setpoints are not adjusted. The NRC staff agrees with the NMPNS determination as the APRM signals are not utilized in the Option III detect and suppress solution.

The PUSAR further states that the OLMCPR adder of 0.01 required by IMLTR SE Condition 19 is not applied in the OPRM setpoint calculation. The staff finds that this approach is consistent with the IMLTR SE Condition Implementation letter [Reference 22]. Including the OLMCPR 0.01 adder would reduce the conservatism in the calculated OPRM setpoint. Therefore, the staff finds that the NMP2 EPU LAR is consistent with Condition 18 and, therefore, acceptable.

2.8.7.1.19 Condition 19: Void Quality Correlation 1

IMLTR SE Condition

For applications involving PANCEA/ODYN/ISCOR/TASC for operation at EPU and MELLLA+, an additional 0.01 will be added to the OLMCPR, until such time that GE expands the experimental database supporting the Findlay-Dix void-quality correlation to demonstrate the accuracy and performance of the void-quality correlation based on experimental data representative of the current fuel designs and operating conditions during steady-state, transient, and accident conditions.

PUSAR Disposition

Section 2.8.5.8 and 2.8.3.1 of the PUSAR states that the 0.01 OLMCPR adder specified by Condition 19 is applicable to NMP2 EPU and will applied to the EPU core design through the RLA process. Therefore, the NRC staff finds that disposition of Condition 19 is acceptable.

2.8.7.1.20 Condition 20: Void Quality Correlation 2

IMLTR SE Condition

The adequacy of the TRACG interfacial shear model qualification for application to EPU and MELLLA+ will be addressed under this review. Any conclusions specified in the NRC staff SE approving Supplement 3 to LTR NEDC-32906P [Reference 39] will be applicable as approved.

PUSAR Disposition

The PUSAR states that the transient analyses for AOO and ATWS are not performed with TRACG04. However, the staff notes that in its review of the Migration LTR (NEDC-32906P Supplement 3) the staff found that the interfacial shear model was adequately qualified for GE14 and earlier fuel designs that the use of TRACG04 to perform the AOO transient analyses would not require the OLMCPR adder imposed on ODYN calculations by Condition 19 [Reference 36]. The SE for the Migration LTR specifies that applicability of the interfacial shear model must be demonstrated for future GNF fuel designs (beyond GE14). Yet, the NMP2 LAR does not request approval for a fuel transition to a fuel design other than GE14. TRACG04 is not utilized for the transient analysis (AOO, ASME overpressure, or ATWS). Therefore, the staff finds that the condition is not applicable to NMP2 on the basis that the NMP2 EPU transient analyses are performed using ODYN.

2.8.7.1.21 Condition 21: Mixed Core Method 1

IMLTR SE Condition

Plants implementing EPU or MELLLA+ with mixed fuel vendor cores will provide plant-specific justification for extension of GE's analytical methods or codes. The content of the plant-specific application will cover the topics addressed in this SE as well as subjects relevant to application of GE's methods to legacy fuel. Alternatively, GE may supplement or revise LTR NEDC-33173P [Reference 20] for mixed core application.

PUSAR Disposition

The NMP2 EPU core will consist entirely of GE14 fuel. Therefore, the mixed core method condition is not applicable to the current review.

2.8.7.1.22 Condition 22: Mixed Core Method 2

IMLTR SE Condition

For any plant-specific applications of TGBLA06 with fuel type characteristics not covered in this review, GE needs to provide assessment data similar to that provided for the GE fuels. The Interim Methods review is applicable to all GE lattices up to GE14. Fuel lattice designs, other than GE lattices up to GE14, with the following characteristics are not covered by this review:

- Square internal water channels or water crosses
- Gd rods simultaneously adjacent to water and vanished rods
- 11x11 lattices
- MOX fuel

The acceptability of the modified epithermal slowing down models in TGBLA06 has not been demonstrated for application to these or other geometries for expanded operating domains.

Significant changes in the Gd rod optical thickness will require an evaluation of the TGBLA06 radial flux and Gd depletion modeling before being applied. Increases in the lattice Gd loading that result in nodal reactivity biases beyond those previously established will require review before the GE methods may be applied.

PUSAR Disposition

The NMP2 EPU core will consist entirely of GE14 fuel. Therefore, the mixed core method condition is not applicable to the current review.

2.8.7.1.23 <u>Condition 23: MELLLA+ Eigenvalue Tracking</u>

IMLTR SE Condition

In the first plant-specific implementation of MELLLA+, the cycle-specific eigenvalue tracking data will be evaluated and submitted to NRC to establish the performance of nuclear methods under the operation in the new operating domain. The following data will be analyzed:

- Hot critical eigenvalue,
- Cold critical eigenvalue,
- Nodal power distribution (measured and calculated TIP comparison),
- Bundle power distribution (measured and calculated TIP comparison),
- Thermal margin,
- Core flow and pressure drop uncertainties, and
- The MIP Criterion (e.g., determine if core and fuel design selected is expected to produce a plant response outside the prior experience base).

Provision of evaluation of the core-tracking data will provide the NRC staff with bases to establish if operation at the expanded operating domain indicates: (1) changes in the performance of nuclear methods outside the EPU experience base; (2) changes in the available thermal margins; (3) need for changes in the uncertainties and NRC-approved criterion used in the SLMCPR methodology; or (4) any anomaly that may require corrective actions.

PUSAR Disposition

The scope of the current LAR does not request approval for operation in the MELLLA+ domain. Therefore, the condition is not applicable to the current review.

2.8.7.1.24 <u>Condition 24: Plant-specific Application</u>

IMLTR SE Condition

The plant-specific applications will provide prediction of key parameters for cycle exposures for operation at EPU (and MELLLA+ for MELLLA+ applications). The plant-specific prediction of these key parameters will be plotted against the EPU Reference Plant experience base and MELLLA+ operating experience, if available. For evaluation of the margins available in the fuel design limits, plant-specific applications will also provide quarter core map (assuming core symmetry) showing bundle power, bundle operating LHGR, and MCPR for BOC, MOC, and EOC. Since the minimum margins to specific limits may occur at exposures other than the traditional BOC, MOC, and EOC, the data will be provided at these exposures.

PUSAR Disposition

Section 2.8.2.5.4 of the PUSAR provides the information required by Condition 24 in the plant-specific LAR. These data include calculations of the key operating parameters for cycle exposure at EPU conditions. These parameters are compared to equivalent parameters for the plants in the extended database described in the IMLTR. The NRC staff reviewed Figures 2.8-1 through 2.8-18 provided in the PUSAR[34]. The staff concluded that the information provided was sufficient to meet the requirements of Condition 24.

The staff confirmed that the expected operational conditions for EPU at NMP2 are expected to be consistent with the operating conditions for the plants and cycles included in the extended database. Therefore, the staff finds that Condition 24 has been acceptably addressed.

2.8.7.2 Local Power Range Monitor Calibration Interval

It has come to the staff's attention that there is an error in the LHGR uncertainty analysis provided in the IMLTR. The LHGR uncertainty analysis includes the LPRM update uncertainty of [[ ]] percent. However, the basis for this value is the bundle power whereas the LHGR is monitored on a nodal level with uncertainties that take into account the peak pin power uncertainty.

Appendix B of NEDC-32694P-A (Reference 47) provides a revised LPRM update uncertainty for the LHGR evaluation of [[ ]] percent. Appendix B of NEDC-32694P-A provides a calculation of the LHGR uncertainties and calculates this value as 5.41 percent. [[

]].

When this update uncertainty is corrected in the IMLTR LHGR uncertainty calculation (see Table 2-11 from the IMLTR) the resultant LHGR uncertainty is [[ ]] percent. This value remains below the value assumed in the thermal-mechanical (T-M) analysis.

However, the value of the LPRM update uncertainty is a function of the exposure interval between LPRM calibrations. As the exposure interval increases the uncertainty associated with the nodal power attributed to the update uncertainty component is expected to increase. The proposed NMP2 LPRM calibration interval is defined as 1000 effective full-power hours. Since the license amendment requests an increase in the licensed thermal power, the calibration interval in terms of accumulated exposure would increase.

The staff requested additional information in RAI SNPB-1 regarding the justification for the proposed calibration interval. NMPNS provided the LPRM exposure interval at EPU and pre-EPU conditions using consistent units in terms of exposure. The NMP2 exposure interval between LPRM calibrations at pre-EPU conditions is [[ ]] MWD/MT [megawatt days per metric ton]. Given consideration of the EPU, the calibration interval would be increased to [[ ]] MWD/MT (Reference 3).

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[34] Figures 2.8-11, 2.8-12, and 2.8-17 of the PUSAR plot bundle operating LHGR in units of 10 kW/ft. The staff provides this clarification as the figure labeling is not explicitly clear. See the legends provided in the Figures for correct scaling.

NMPNS justified the continued applicability of the LPRM update uncertainty be performing a comprehensive study using core-monitoring information from several recent plants and cycles. The modern database referenced in the RAI response includes BWR/4-6 plants with lattice configurations and core sizes that encompass the NMP2 plant design. The modern database includes data for LPRM calibration intervals that are bounding of the NMP2 EPU exposure interval Reference 3.

The NRC staff reviewed the question of the effects of the interval calibration increase and the associated uncertainty in RAI SNPB-1. The staff audited additional information regarding the modern database and comprehensive study at the GEH offices in Washington, DC on January 29, 2010. The staff findings are provided in Reference 53 (proprietary). The audit of the basis material determined that the scope of the comprehensive study was sufficient to encompass the operating conditions and LPRM calibration interval for NMP2 at EPU power levels. The staff independently verified the applicability of the study and confirmed that the [[ ]] percent continues to apply. The staff's audit confirmed that the comprehensive study and the associated modern database are applicable to NMP2 and that the data are sufficient to confirm that the generic LPRM update uncertainty is adequate.

On the basis that qualification data from the comprehensive study confirm the continued applicability of the generic value referenced in Appendix B of NEDC-32964P-A (Reference 47) the staff finds that the current uncertainty analysis remains applicable to NMP2. The LHGR component uncertainty as stated above is calculated to be [[ ]] percent. This value remains below the [[ ]] percent assumed in the T-M analysis. Therefore, the staff finds that the T-M analyses are adequately conservative to account for the NMP2 EPU LPRM calibration exposure interval. Therefore, the T-M analyses are acceptable.

2.8.7.3 Conclusion

The NRC staff has reviewed the information provided in the PUSAR and the responses to the NRC staff's requests for additional information. On the basis of the disposition of IMLTR SE conditions in Appendix A of the PUSAR and the RAI responses, the NRC staff has concluded that the NMP2 safety analyses were performed consistent with the approval of the GEH analytical methods described in NEDC-33173P [Reference 20]. Therefore, the NRC staff finds that the analysis methods are acceptable.

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 EPUs 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 NMP2 FSAR related to liquid waste management systems and gaseous waste management systems. The NRC'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 limiting conditions for operation to meet the "as low as is reasonably achievable" 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. Additionally, the reactor coolant isotopic activity concentration is a function of the core power level, the migration of radionuclides from the fuel, the presence of corrosion products or contaminants, radioactive decay, and the removal of radioactive material by coolant purification systems. The licensee previously submitted a separate LAR to implement an AST in accordance with 10 CFR 50.67, which the NRC approved in a letter dated May 29, 2008, as Amendment No. 125 to Facility Operating License No. NPF-69 for NMP2. The analyses supporting the EPU amendments included a core isotopic source term calculated for the EPU conditions, and were performed with consideration of, and are applicable to, both GE11 fuel and GE14 fuel.

In Section 2.9.1 of the PUSAR, the licensee discussed the impact of the EPU on the radiation sources in the reactor coolant. 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 nonradioactive isotope oxygen-16 is activated to become radioactive nitrogen-16 by a neutron-proton reaction as it passes through the neutron-rich core at power. The coolant activation, especially nitrogen-16 activity, is the dominant source in the turbine building and in the lower regions of the drywell. The increase in the activation of the water in the core region is in approximate proportion to the increase in thermal power. The licensee asserts in Section 2.9.1 of the PUSAR that since the margin in the current NMP2 plant design basis for reactor coolant activation concentrations exceeds potential increases resulting from the EPU; no change is required in the activation design-basis reactor coolant concentrations for the EPU. The licensee's evaluation shows that the activation products in the steam from operation are bounded by the existing design basis concentration.

The reactor coolant contains activated corrosion products, which are the result of metallic materials entering the water and being activated in the reactor region. Under EPU conditions, the feedwater flow and the activation rate in the reactor increase with power. This results in an increase in activated corrosion product production. The licensee calculated that the total activated corrosion product activity to be less than 28 percent of the design basis levels. The increase in the corrosion product activity is proportional to the increase in reactor power.

Fission products in the reactor coolant are separable into the products in the steam and the products in the reactor water. The activity in the steam consists of noble gases released from the core plus carryover activity from the reactor water. This activity is the noble gas offgas that is included in the plant design. The licensee calculated offgas rates for EPU, after 30 minutes decay, to be 0.037 curies per second. This is well below the original design basis of 0.35 curies per second. Therefore, the licensee asserts that no change is required in the design basis or

TS limit for offgas activity as a result of the EPU. The NRC staff agrees with the licensee that the current design basis for offgas activity remains bounding. The increase in the offgas activity is proportional to the increase in reactor power.

The fission product activity in the reactor water, like the activity in the steam, is the result of minute releases from the fuel rods. EPU fission product activity levels in the reactor water remain a fraction (< 12 percent) of the design basis fission product activity. The licensee calculated the total activated corrosion product activity to be less than 28 percent of design basis levels. The sum of the activated corrosion product activity and the fission product activity remains a small fraction (< 12 percent for water, <15 percent for steam) of the total design basis activity. Therefore, the licensee concludes that the activated corrosion product and fission product activities design bases for NMP2 are unchanged for EPU. Based on the above evaluations and considering that the licensee has used methodologies in the current licensing basis and in accordance with the SRP 11.1 to evaluate the impact of the uprate on the radiation sources in the reactor coolant, the NRC staff finds the licensee's evaluation acceptable, because the total reactor coolant activity remains bounded at the EPU level.

Conclusion

The NRC staff has reviewed the radioactive source term associated with the proposed EPU 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, Appendix I to 10 CFR Part 50, and GDC-60. Therefore, the NRC staff finds the proposed EPU acceptable with respect to source terms.

2.9.2 Radiological Consequences Analyses Using Alternative Source Terms

Regulatory Evaluation

The NRC staff reviewed the DBA radiological consequences analyses performed at the EPU power level that the licensee submitted in support of the NMP2 AST license amendment. In support of the AST amendments, the licensee evaluated all significant DBAs currently analyzed for radiological consequences in the NMP2 FSAR. The radiological consequences analyses reviewed are the loss-of-coolant accident (LOCA), fuel-handling accident (FHA), control rod drop accident (CRDA), and main steamline break (MSLB). 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 by the licensee for the calculation of the total effective dose equivalent (TEDE). The NRC based its acceptance criteria for radiological consequences analyses using an AST on 10 CFR 50.67. These criteria are 25 rem TEDE at the exclusion area boundary for any 2-hour period following the onset of the postulated fission product release, 25 rem TEDE at the outer boundary of the low-population zone for the duration of the postulated fission product release, and 5 rem TEDE for access and occupancy of the control room for the duration of the postulated fission product release. Regulatory Position 4.4 of RG 1.183 and Table 1 of SRP Section 15.0.1 contain accident-specific criteria for the exclusion area boundary and the low-population zone, supplementing 10 CFR 50.67.

Technical Evaluation

Section 2.9.2 of the PUSAR discusses the impact of the EPU on the radiological consequences of DBAs. The licensee performed DBA dose analyses at a power level of 4067 MWt, which is 102 percent of the proposed EPU rated thermal power (RTP) level of 3988 MWt. The licensee submitted these analyses by letter dated May 31, 2007, and requested a license amendment to revise the NMP2 licensing basis to support a full-scope implementation of an AST in accordance with 10 CFR 50.67. The NRC staff found the AST DBA dose analyses to be acceptable and issued Amendment No. 125 to Facility Operating License No. NPF-69.

In support of the AST amendments, the licensee evaluated all significant DBAs currently analyzed for radiological consequences in the NMP2 FSAR. The radiological consequences analyses reviewed are the LOCA, FHA, CRDA, and MSLB. In its previous review for the AST amendments, the NRC staff compared the doses estimated by the licensee to the applicable regulatory criteria and found, with reasonable assurance, that the licensee's estimates of the offsite and control room doses will continue to comply with the applicable regulatory criteria. The SE for the AST amendment stated that the NRC staff found that the radiological consequences of DBAs would remain bounding up to an RTP of 3988 MWt. Based on its review of the impact of the EPU on the radiological consequences of DBA's, the staff finds the licensee's evaluation acceptable.

Conclusion

The NRC staff has evaluated the licensee's revised accident analyses performed in support of the proposed EPU and concludes that the licensee has adequately accounted for the effects of the proposed EPU. The NRC staff further concludes that the plant site and the dose-mitigating ESF systems remain acceptable with respect to the radiological consequences of postulated DBAs since, as set forth above, the calculated TEDE at the exclusion area boundary, at the low-population zone outer boundary, and in the control room meet the acceptance criteria specified in 10 CFR 50.67, as well as applicable acceptance criteria denoted in SRP Section 15.0.1. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to the radiological consequences of DBAs.

2.10 Health Physics

Regulatory Evaluation

The NRC staff conducted its review in this area to ascertain what overall effects operating NMP2 at 3988 MWt would have on both occupational and public radiation doses and to determine whether the licensee has taken the necessary steps to ensure that any dose increases will be maintained within applicable regulatory limits and as low as is reasonably achievable (ALARA).

The NRC staff's review included an evaluation of any increases in radiation sources and how this may affect plant area dose rates, plant radiation zones, and plant area accessibility. The NRC staff evaluated how personnel doses needed to access plant vital areas following an accident are affected. The NRC staff considered the effects of the proposed EPU on Nitrogen-16 (N-16) levels in the plant as well as any effects on radiation doses outside the plant, and at the site boundary, from skyshine. The NRC staff also considered the effects of the proposed EPU on plant effluent levels and any increased radiation doses from those effluents at the site boundary. The projected radiological impacts to the public from the entire site (e.g., all three units operating) with NMP2 operating at EPU were evaluated as appropriate. The NRC's acceptance criteria for occupational and public radiation doses are based on 10 CFR Part 20, 40 CFR Part 190, 10 CFR 50.67, 10 CFR Part 50 Appendix I, and GDC-19. Specific review criteria are contained in SRP Sections 12.2, 12.3, 12.4, and 12.5, NUREG-0737, item II.B.2, and other guidance provided in Matrix 10 of RS-001.

2.10.1 Occupational and Public Radiation Doses

Technical Evaluation

Source Terms

In general, the production of radiation and radioactive material (either fission or activation products) in the reactor core are directly dependent on the neutron flux and power level of the reactor. Therefore, as a first order approximation, a 15 - 20 percent increase in power level is expected to result in a proportional increase in the direct (i.e., from the reactor fuel) and indirect (i.e., from the reactor coolant) radiation source terms. However, due to the physical and chemical properties of the different radioactive materials that reside in the reactor coolant, and the various processes that transport these materials to locations in the plant outside the reactor, several radiation sources encountered in the balance of plant are not expected to change in direct proportion to the increased reactor power. The most significant of these are:

1. The concentration of noble gas and other volatile fission products in the main steam line will not change. The increased production rate of these materials is offset by the corresponding increase in steam flow. Although the concentration of these materials in the steam line remains constant, the increased steam flow results in an increase in the rate these materials are introduced into the Main Condenser and Off Gas systems.

2. For the very short lived activities, such as N-16 with its 7.13 second half-life, the decreased transit (and decay) time in the main steam line, and the increased mass flow of the steam results in a larger increase in these activities in the major turbine building components. The licensee estimates a 30 percent increase in expected dose rates from increase N-16 in the turbine building over the OLTP dose rates.

3. The concentrations of non-volatile fission products, actinides, and corrosion and wear products in the reactor coolant are expected to increase proportionally with the power increase. However, the 15 - 20 percent increase in steam flow is expected to result in small increases in moisture carryover in the steam, resulting in some increased transport of these activities to the balance of the plant. The increases in moisture carryover are expected to be within the current design margin for moisture carryover. Associated increases in dose rates are also expected to be within the shielding design margins for the condensate, feedwater, and other affected systems.

Radiation Protection Design Features

Occupational and Onsite Radiation Exposures

The radiation sources in the core are expected to increase in proportion to the increase in power. This increase, however, is bounded by the existing safety margins of the plant design. Due to the design of the shielding and containment surrounding the reactor vessel, and since the reactor vessel is inaccessible to plant personnel during operation, a 20 percent increase in the radiation sources in the reactor core will have no affect on occupational worker personnel doses during power operations. Similarly, the radiation shielding provided in the balance of plant is conservatively sized such that the increased source terms discussed above are not expected to significantly increase the dose rates in the normally occupied areas of the plant. Radiation dose rates in steam-affected areas of the plant are estimated to increase by approximately 30 percent. These areas are all currently designated as high radiation areas and personnel access to them is restricted and controlled accordingly. The existing radiation zoning design (e.g., the maximum designed dose rates for each area of the plant), for areas outside the steam-affected areas, will not change as a result of the increased dose rates associated with this proposed EPU.

During EPU testing, the licensee will perform sampling and measurements to determine the radiochemical quality of the reactor water, feedwater, and gaseous releases. In addition general area dose rates will be measured at plant locations susceptible to increased N-16 and neutron doses as a result of the power increase. Surveys will be performed in normally accessible areas adjacent to steam affected areas in the Reactor Building (62 locations), Turbine Building (47 locations), Offgas Building (4 Radiation Measurements EPU Test 2 locations) and the Screenwell Building (6 locations). These measurements and sampling will be performed at 100, 105, 110, and EPU (115 percent of CLTP).

Operating at a 20 percent higher power level will result in an increased core inventory of radioactive material that is available for release during postulated accident conditions. The plant shielding design must be sufficient to provide control room habitability, per GDC-19, and operator access to vital areas of the plant, per NUREG-0737 item II.B.2, during the accident. As part of a change to the NMP2 design basis, the licensee recently recalculated the radiological consequences of the postulated design-basis accidents using the Alternate Source Term (AST) in accordance with the provisions in 10 CFR 50.90 and 10 CFR 50.67. The AST provides more realistic assumptions, than the current design basis source term, on the timing and mechanisms of radioactive material release from the core during postulated accident conditions. In reevaluating the design-basis accidents, the licensee recalculated the radiation doses associated with Control Room and Technical Support Center habitability, at the proposed EPU power level, plus a 2 percent instrument uncertainty factor. The staff documented its review and approval of the licensee's use of AST (including these revised dose calculations) in the related SE dated May 29, 2008 (ML081230439). In addition, in their July 30 letter, the licensee estimated the mission dose impact of the proposed EPU for the other vital areas of the plant that require access during a design-basis accident. These areas include the Health Physics/Counting Room; Radwaste Sampling Room and Unit 1 Chemistry Laboratory; Main Stack Online Isotopic Monitors; and the Radwaste Control Room. The mission dose to access each of these areas meets the acceptance criteria of NUREG-0737, item II.B.2.

Therefore, following implementation of the proposed EPU, NMP2 will continue to meet its design-basis in terms of radiation shielding, in accordance with the criteria in SRP Section 12.4, GDC-19, and NUREG-0737, item II.B.2.

Public and Offsite Radiation Exposures

There are two factors, associated with the proposed EPU that may impact public and offsite radiation exposures during plant operations. These are the possible increase in gaseous and liquid effluents released from the site, and the increase in direct radiation exposure from radioactive plant components and solid wastes stored onsite. As described above, the proposed EPU will result in a 20 percent increase in gaseous effluents released from the plant during operations. This increase is a minor contribution to the radiation exposure of the public. The nominal annual public dose from plant gaseous effluents for NMP2 is typically a small fraction of the design criteria of 10 CFR 50, Appendix I, and the EPA's dose limits in 40 CFR Part 190 (as referenced by 10 CFR 20 paragraph 20.1301 (e)). For example during the reporting period of January 1 to December 31, 2009 the maximum dose to a member of the public resulting from airborne releases from the NMP2 plant, was much less than 1 percent of 40 CFR Part 190 and the dose based, ALARA design criteria in 10 CFR Part 50, Appendix I. Even with the conservative assumption that power operations at the proposed EPU increases this by 50 percent, the dose to the public from airborne effluents will continue to be well below these applicable regulatory requirements.

The proposed EPU will also result in increased generation of liquid and solid radioactive waste. The increased condensate feed flow associated with the proposed EPU results in faster loading of the condensate demineralizers. Similarly, the higher feed flow introduces more impurities into the reactor resulting in faster loading of the reactor water cleanup (RWCU) system demineralizers. Therefore, the deminerlizers in both of these systems will require more frequent back washing to maintain them. The licensee has estimated that these more frequent backwashes will increase the volume of liquid waste that will need processing by less than 10 percent and an increase in processed solid radioactive waste by about 7 percent. These increases are well within the processing capacity of the radwaste systems and are not expected to noticeably increase the liquid effluents or solid radioactive waste released from the plant. Therefore, these increases will have a negligible impact on occupational or public radiation exposure.

Skyshine is a physical phenomenon associated with gamma radiation that is emitted skyward, during radioactive decay. As this radiation interacts with air molecules, some is scattered back down to the ground where it can expose members of the public. Since there is significantly less radiation shielding above the steam components in the turbine building, than there is to the sides of these components, skyshine from N-16 gammas can be a significant contributor to dose rates outside plant buildings (both onsite and offsite). As discussed above, the licensee has estimated that plant operations at the proposed EPU will increase the N-16 activity in the turbine building. In addition, the practice of injecting hydrogen into the reactor feedwater, to reduce stress-corrosion cracking, significantly increases the fraction of N-16 in the reactor water that is released into the steam during power operations. For the effluent reporting periods 2004 through 2009, the maximum annual offsite whole body dose was 2.76 mrem from the combined operations of NMP Units 1 and 2, and FitzPatrick. Applying a conservative factor of 1.3 to account for the reduced decay time from increased NMP2 steam flow rate, results in a maximum expected annual dose to an offsite member of the public of approximately 3.59 mrem.

This is well within the annual limit of 25 mrem to an actual member of the public in 40 CFR Part 190, as referenced by 10 CFR Part 20, paragraph 20.1301 (e).

Operational Radiation Protection Program

The increased production of non-volatile fission products, actinides and corrosion and wear products in the reactor coolant may result in proportionally higher plate-out of these materials on the surfaces of, and low flow areas in, reactor systems. The corresponding increase in dose rates associated with these deposited materials will be an additional source of occupational exposure during the repair and maintenance of these systems. However, the current ALARA program practices at NMP2 (e.g., work planning, source term minimization, etc.), coupled with existing radiation exposure procedural controls, will be able to compensate for the anticipated increases in dose rates associated with the proposed EPU. Therefore, the increased radiation sources resulting from this proposed EPU, as discussed above, will not adversely impact the licensees ability to maintain occupational and public radiation doses within the applicable limits in 10 CFR Part 20 and ALARA.

Conclusion

The NRC staff has reviewed the licensee's assessment of the effects of the proposed EPU on radiation source terms and plant radiation levels. The NRC staff concludes that the licensee has taken the necessary steps to ensure that any increases in radiation doses will be maintained as low as is reasonably achievable. The NRC staff further concludes that the proposed EPU meets the requirements of 10 CFR Part 20, 40 CFR Part 190, 10 CFR Part 50, Appendix I, NUREG-0737, and GDC-19. Therefore, the NRC staff finds the licensee's proposed EPU acceptable with respect to radiation protection and ensuring that occupational and public radiation exposures will be maintained within these applicable limits and ALARA.

2.11 Human Performance

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 conducted its human factors evaluation to ensure that operator performance would not be adversely affected as a result of system and procedure changes made to implement the proposed EPU. The NRC staff's review covered changes to operator actions, human-system interfaces, and procedures and training needed for the proposed EPU. The NRC's acceptance criteria for human factors are based on GDC-19 and the guidance in GL 82-33, "Supplement 1 to NUREG-0737—Requirements For Emergency Response Capability," dated December 17, 1982. SRP Chapter 18.0 and RS-001 contain specific review criteria.

2.11.1 Emergency and Abnormal Operating Procedures

This section includes a summary of the licensee's assessment of how the proposed EPU will change the plant emergency and abnormal operating procedures, and the staff's evaluation of that assessment.

NMP2 identified the following changes:

Emergency Operating Procedures

- The EPU will result in additional heat being added to the suppression pool during certain accident scenarios. The Heat Capacity Temperature Limit (HCTL) curve will be revised as a result of the increase in decay heat rejected to the suppression pool.
- The Pressure Suppression Pressure Curve will be revised as a result of the increase in reactor power and in decay heat loading.
- The Cold Shutdown Boron Weight will be revised as a result of the increase in the equilibrium core design for EPU by - 18 percent. The Hot Shutdown Boron Weight is expected to be impacted by an equivalent amount. Upon cycle specific analysis these values will be confirmed.

Abnormal Operating Procedures (Special Operating Procedures)

- Adjustments planned for various procedures to address the new full power value but the event mitigation philosophy will remain unchanged
- The Reactor Recirculation Runback Logic will be modified to initiate the runback immediately upon a feedwater pump trip.
- Loss of Vacuum procedures will be revised to include the Turbine Back Pressure Alarm Limit, which will allow operation closer to the trip setpoint by changing the alarm setpoint
- Main Condenser Tube Rupture / Condensate High Conductivity procedures will be revised. Steps were added to verify closure of the condensate demineralizer bypass valve installed as part of EPU modifications.
- Loss of Spent Fuel Pool Cooling have decay heat curves, heat up rates and temperature related data sheets that will be revised to reflect the new EPU values.

These procedure changes and the associated training will be implemented prior to operation at uprated conditions. The changes do not result in any new operator actions or a decrease in the time available for the operator to complete any existing actions included within the procedures. The staff finds these proposed changes to be acceptable.

2.11.2 Manual Operator Actions Sensitive to Power Uprate

This section evaluates any new manual operator actions needed as a result of the proposed EPU and changes to any current manual operator actions related to emergency or abnormal operating procedures that will occur as a result of the proposed EPU.

The licensee stated that there are no new operator actions required to support the proposed EPU. The licensee also stated that the analysis for EPU credits existing manual actions following the same time limits currently credited for the CLTP limit except for the following action.

Proposed EPU conditions credit operators initiating the hydrogen recombiners in 32.6 hours in as a part of the procedures to control the combustible a gas control in containment following a LOCA. Currently operators initiate the system in 43.5 hours given the same scenario. This change is acceptable because the time it takes for the overall time for the operator action is a small fraction of the available time given to complete the task. The licensee stated in a response to the staff's request for additional information, the time required for task completion is 2.0 hours including 1.5 hours for the warm up of the system. This change is acceptable because of the amount of margin for the operator to complete the task and the amount of time it will take the operator to perform the action in comparison to the time available.

2.11.3 Changes to Control Room Controls, Displays, and Alarms

This section evaluates any changes the proposed EPU will have on the operator interfaces for control room controls, displays, and alarms.

In its submittal, NMP2 described changes to control room controls, displays, and alarms related to the proposed EPU. As a part of the modification process, the operations and training departments will perform an impact review of the changes to the control room as a result of the proposed EPU. The change process also includes a Human factors engineering review. The results of the reviews are incorporated into the Engineering Change Package. Training requirements are identified and tracked as a part of the design change process. NMP2 listed in its submittal the setpoints for the various instrument and control systems that were evaluated for EPU conditions and determined to be impacted.

The purpose of this section is to assure that the licensee has adequately considered the equipment changes resulting from the EPU 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 EPU-related changes in the control room and the corresponding operator training and simulator modifications prior to EPU implementation. The NRC staff has reviewed the licensee's evaluation and proposed changes to the control room. The NRC staff concludes that the proposed changes discussed above do not present any adverse effects to the operators' functions in the control room. NMP2 stated that all modifications to the control room and the associated changes to operator training will take place prior to EPU implementation.

2.11.4 Changes to The Safety Parameter Display System (SPDS)

The Safety Parameter Display System (SPDS) will be revised to address the changes to the control room 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.

NMP2 stated in its submittal that SPDS equipment is not being modified for the EPU. The information presented on the SPDS displays and the method of presentation remains unchanged for EPU. The NMP2 SPDS system also provides procedure based display concepts to support execution of the NMP2 EOPs. In conjunction with changes required to the EOPs for EPU operation, the following SPDS EOP curves will be revised:

- Pressure Suppression Pressure (PSP)
- Heat Capacity Temperature Limit (HCTL)

The NRC staff reviewed the proposed changes to the SPDS as described by NMP2 in its submittal. The NRC 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.

2.11.5 Control Room Plant Reference Simulator and Operator Training

This section includes the review of changes to the operator training program and the plant-referenced control room simulator resulting from the proposed EPU and the implementation schedule for making the changes. In its submittal, NMP2 stated that the training will focus on the plant modifications, procedure changes, start up and test requirements and other aspects of EPU. NMP2 also stated that the training will highlight the changes that impact EOPs and AOPs. As determined by the training analysis process, appropriate classroom, simulator, and in-plant training will be conducted prior to power escalation or as required to operate modified systems on start up.

NMP2 also stated that the installation of the EPU changes to the simulator will be performed in accordance with ANSI/ANS-3.5 1998, "Nuclear Power Plant Simulators for Use in Operator Training and Evaluation." The simulator changes will include hardware changes for new and modified control room instrumentation and controls, software updates for modeling changes due to EPU and re-tuning of the core physics model for cycle specific data. Operating data will be collected during EPU implementation and start-up testing. Simulator performance will be validated using design analysis data and start up and test data from the EPU project and implementation program.

The NRC staff concludes that NMP2 proposed changes to the operator training program, including simulator training, are acceptable for the proposed EPU. The staff also finds that these changes are being made in accordance to 10 CFR 55.59 and 50.120.

Conclusion

The NRC staff has reviewed the licensee-identified changes to operator actions, human-system interfaces, procedures, and training required for the proposed EPU and concludes that NMP2 has: (1) appropriately accounted for the effects of the proposed EPU on the available time for operator actions and (2) taken appropriate actions to ensure that operator performance is not adversely affected by the proposed EPU. The NRC staff further concludes that the licensee will continue to meet the requirements of GDC-19, 10 CFR 50.120(b)(2)(i) and 10 CFR 50.120(b)(3), and 10 CFR 55.59(c) following implementation of the proposed EPU. Therefore, the NRC staff finds the licensee's proposed EPU acceptable regarding the human factors aspects of the required system changes.

2.12 Power Ascension and Testing Plan

2.12.1 Approach to EPU Power Level and Test Plan

Background

By letter dated May 27, 2009, NMPNS submitted an EPU LAR for NMP2 in accordance with 10 CFR 50.90. The proposed amendment plans to increase the power level authorized by Operating License (OL) Section 2.C.(1), Maximum Power Level, from 3467 megawatts-thermal (MWt) to 3988 MWt. The new maximum power level represents an increase of 20 percent from the Original Licensed Thermal Power (OLTP) level of 3323 MWt and an increase of 15 percent from the Current Licensed Thermal Power (CLTP) level of 3467 MWt. In Amendment No. 66, dated April 28, 1995, the NRC staff approved a Stretch Power Uprate authorizing the increase from 3323 MWt to 3467 MWt.

The technical bases for this request follow the guidelines contained in the NRC-approved General Electric Nuclear Energy (GENE) Licensing TRs (LTRs) for EPU safety analysis: NEDC-33004P-A, "Constant Pressure Power Uprate," (CLTR), Revision 4; NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1), which the NRC determined to be an acceptable methodology for requesting EPUs; and NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR2).

GE Hitachi Nuclear Energy NEDO-33351, "Safety Analysis Report for Nine Mile Point Nuclear Station Unit 2 Constant Pressure Power Uprate (PUSAR)" (non-proprietary version), provided as Attachment 3 to the Enclosure of the LAR, provides an integrated summary of the results of the safety analyses and evaluations performed that support the proposed increase in the maximum power level at NMP2. The PUSAR SE follows the format and guidance delineated in RS-001 to the extent that the review standard is consistent with the design-basis of NMP2. For differences between the plant-specific design bases and RS-001 regulatory evaluation sections, the corresponding PUSAR SE regulatory evaluation section was revised to reflect the NMPNS design basis. NRC staff guidance for reviewing EPU test programs is described in NUREG-0800, Standard Review Plan (SRP) 14.2.1, "Generic Guidelines for EPU Testing Programs." The staff review focused on NMP2 adequately addressing the guidance described in the SRP.

Regulatory Evaluation

The purpose of the EPU test program is to demonstrate that structures, systems, and components (SSCs) will perform satisfactorily in service at the proposed EPU power level. The test program also provides additional assurance that the plant will continue to operate in accordance with design criteria at EPU conditions. The NRC staff's review included an evaluation of: (1) plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance; (2) transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level; and (3) the test program's conformance with applicable regulations.

The NRC's acceptance criteria for the proposed EPU test program are based on 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," which requires establishment of a test program to demonstrate that SSCs will perform satisfactorily in service. Additionally, specific review criteria are contained in Section III of NUREG-0800, SRP 14.2.1. Other guidance is also provided in Section 2 and Insert 12 of NRC Review Standard for Extended Power Uprates (RS-001). The staff's review focused on NMPNS adequately addressing the guidance described in the SRP. The licensee's proposed PATP follows the guidelines contained in NRC-approved GENE LTRs which the staff determined to be an acceptable methodology for licensees requesting EPUs.

Technical Evaluation

2.12.2 SRP 14.2.1, Section III.A, Comparison of Proposed EPU Test Program to the Initial Plant Test Program

SRP 14.2.1 Section III.A, specifies the guidance and acceptance criteria which the licensee should use to compare the proposed EPU testing program to the original power-ascension test program performed during initial plant licensing. The scope of this comparison should include: 1) all initial power-ascension tests performed at a power level of equal to or greater than 80 percent OLTP level; and 2) initial test program tests performed at lower power levels if the EPU would invalidate the test results. The licensee shall either repeat initial power-ascension tests within the scope of this comparison or adequately justify proposed test deviations. The following specific criteria should be identified in the EPU test program:

- All power-ascension tests initially performed at a power level of equal to or greater than 80 percent of the OLTP level;
- All initial test program tests performed at power levels lower than 80 percent of the OLTP level that would be invalidated by the EPU; and
- Differences between the proposed EPU power-ascension test program and the portions of the initial test program identified by the previous criteria.

The staff reviewed applicable sections of the NMP2 USAR, Revision 17, October 2006, Chapter 14, "Initial Test Program," which provided general requirements and an overview of the initial startup tests performed. The staff also reviewed information in USAR Chapter 14 which described the general requirements and startup and power ascension testing performed from initial plant startup to full rated power to demonstrate that the plant was capable of operating safely and satisfactorily. The staff also reviewed the following information provided to the staff in the EPU LAR:

- Attachment 3 of the Enclosure to NMPNS's LAR dated May 27, 2009, "NEDO-33351, Safety Analysis Report for Nine Mile Point Nuclear Station Unit 2 Constant Pressure Power Uprate (PUSAR)," dated May 2009 (non-proprietary version), contained the power uprate safety analysis report (PUSAR) formatted in accordance with RS-001. The PUSAR is an integrated summary of the results of the safety analysis and evaluations performed specifically for the NMP2 EPU and follows the guidelines contained in GENE LTR NEDC-33004P-A, "Constant Pressure Power Uprate," (CLTR).

  The NRC staff has approved the basis for an EPU LAR request with the exception of [[
  ]].

- Attachment 6 of the Enclosure to NMPNS's LAR dated May 27, 2009, "Modifications to Support EPU," provided a list of modifications planned for EPU implementation which do not constitute regulatory commitments. The planned modifications will be implemented in accordance with the requirements of 10 CFR 50.59.

- Attachment 7 of the Enclosure to NMPNS's LAR dated May 27, 2009, "EPU Test Plan," provided a discussion of the EPU testing planned and provided a comparison of initial startup and EPU testing. Section 5.0 provided a justification for [[ ]]. This enclosure supplements PUSAR Section 2.12.

The NRC staff also found that all transient tests described in the initial startup test program were listed in Table 7-1, "Comparison of NMP Initial Startup Testing and Planned EPU Testing," of Attachment 7. Table 4-1, "Startup Transient Tests," of Attachment 7, and Section 4.0, "Testing Evaluations," provided a discussion of power ascension startup tests initially performed at 80 percent OLTP or greater. The staff noted that the two large transient testings (LTTs), SUT-25 (Full Main Steam Isolation Valve (MSIV) Closure) and SUT-27 (Turbine Trip/Generator Load Rejection), were initially performed at 95.3 percent OLTP and 99.6 percent OLTP, respectively. These tests follow the tests described in Attachment 2 of the NRC staff's SRP 14.2.1.

The NMPNS PATP for NMP2 does not include [[ ]] as part of the LAR. The justification for not performing [[ ]] was presented in Attachment 7 of the LAR which provides a discussion of the PATP covering power ascension up to the full 120 percent OLTP (3988 MWt) condition to verify acceptable performance. NMPNS's justification for a test program that does not include all of the power-ascension testing that would normally be performed is further discussed in "SRP 14.2.1, Section III.C," of this SE.

The NMPNS PATP is primarily an initial power ascension test plan designed to assess steam dryer and selected piping system performance from CLTP of 3,467 MWt to uprated power of 3,988 MWt. NMPNS also plans to perform confirmatory inspections for a period of time following initial and continued operation at EPU levels. Testing will be performed in accordance with the TS Surveillance Requirements on instrumentation that is re-calibrated for EPU conditions. Steady-state data will be taken during power ascension and continuing at each EPU power increase increment. EPU power increases above 100 percent CLTP will be made along an established flow control/rod line in increments of equal to or less than 5 percent power. Steady-state data will be taken at points from 90 up to 100 percent of CLTP rated thermal power (RTP) so that system performance parameters can be projected for EPU power before the CLTP RTP is exceeded. Power ascension will occur over a period of time with gradual increases in power and hold periods. NMPNS is also performing post-modification testing, calibration and normal surveillance, as required, to ensure that systems will operate in accordance with their design requirements.

The NRC staff concludes through comparison of the documents referenced above, including a review of the initial startup tests and planned EPU testing described in Attachment 7 and the applicable sections of the NMP2 USAR, that the proposed power ascension test program conforms to the NRC's acceptance criteria of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," including specific review criteria contained in Section III.A. of SRP 14.2.1, and other staff guidance provided in RS-001. Therefore, the proposed power ascension and test plan is acceptable.

2.12.3 SRP 14.2.1, Section III.B, Post Modification Testing Requirements for Functions Important to Safety Impacted by EPU-Related Plant Modifications

Section III.B of SRP 14.2.1 specifies the guidance and acceptance criteria which the licensee should use to assess the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to an anticipated operational occurrence (AOO). AOOs include those conditions of normal operation that are expected to occur one or more times during the life of the plant and include events such as loss of all offsite power, tripping of the main turbine generator set, and loss of power to all reactor coolant pumps. The EPU test program should adequately demonstrate the performance of SSCs important to safety that meet all of the following criteria: (1) the performance of the SSC is impacted by EPU-related modifications; (2) the SSC is used to mitigate an AOOs described in the plant-specific design basis; and, (3) involves the integrated response of multiple SSCs.

The NRC staff reviewed Attachment 6, "Modifications to Support EPU," to the LAR which described the planned modifications necessary to support the EPU that are currently anticipated and that are being prepared for implementation through 2012. NMPNS plans to complete the necessary modifications to achieve a 120 percent increase above OLTP prior to the conclusion of the 2012 refueling outage N2R13. The staff also reviewed NMPNS's aggregate impact analysis of the modifications necessary to support the EPU and agreed that the impact of most of these modifications on normal plant operations is minimal. Post modification testing associated with the proposed modifications include functional performance checks, component performance measurements, equipment calibrations and pressure drop measurements at full flow conditions. NMPNS stated that plant modifications, setpoint adjustments and parameter changes will be demonstrated by a test program established for a Boiling-Water Reactor (BWR) EPU in accordance with startup test specifications as described in PUSAR Section 2.12.1. The startup test specifications are based upon analyses and GE BWR experience with uprated plants to establish a standard set of tests for initial power ascension for CPPU. Some of the planned modifications considered by NMPNS affect the high pressure turbine, feedwater pumps, and condensate and feedwater system upgrades.

The NRC staff concludes that the PATP proposed by NMPNS demonstrates that EPU related modifications will be adequately implemented. Specifically, the staff concludes that based on a review of the listing of completed and planned modifications, including post-maintenance testing associated with these modifications, the proposed EPU test program should adequately demonstrate the performance of SSCs. The staff also concludes that the proposed PATP adequately identified plant modifications necessary to support operation at the uprated power level and complies with the criteria established in Section III.B of SRP 14.2.1.

2.12.4 SRP 14.2.1, Section III.C, Use of Evaluation To Justify Elimination of Power-Ascension Tests

Section III.C. of SRP 14.2.1 specifies the guidance and acceptance criteria the licensee should use to provide justification for a test program that does not include all of the power-ascension testing that would normally be performed, provided that proposed exceptions are adequately justified in accordance with the criteria provided in Section III.C.2.

The proposed EPU test program shall be sufficient to demonstrate that SSCs will perform satisfactorily in service. The following factors should be considered, as applicable, when justifying elimination of power-ascension tests:

- Previous operating experience,
- Introduction of new thermal-hydraulic phenomena or identified system interactions,
- Facility conformance to limitations associated with analytical analysis methods,
- Plant staff familiarization with facility operation and trial use of operating and emergency operating procedures (EOPs),
- Margin reduction in safety analysis results for AOOs,
- Guidance contained in vendor TRs, and
- Risk implications.

The NRC staff's review is intended to provide reasonable assurance that the performance of plant equipment important to safety that could be affected by integrated plant operation or transient conditions is adequately demonstrated prior to extended operation at the requested EPU power level. The staff recognizes that licensees may propose a test program that does not include all of the power-ascension testing referred to in Sections III.A and III.B of SRP 14.2.1 that would normally be performed, provided that proposed exceptions are adequately justified in accordance with the criteria provided in SRP Section III.C.2. If a licensee proposes to omit certain original startup tests from the EPU testing program based on favorable operating experience, the applicability of the operating experience to the specific plant must be demonstrated. Plant design details such as configuration, modifications, and relative changes in setpoints and parameters, equipment specifications, operating power level, test specifications and methods, operating and EOPs, and adverse operating experience from previous EPUs, should be considered and addressed.

The PATP is relied upon as a quality check to confirm that analyses and any modifications and adjustments that are necessary for proposed EPUs have been properly implemented, and to benchmark the analyses against the actual integrated performance of the plant. This is consistent with 10 CFR Part 50, Appendix B, which states that design control measures shall provide for verifying or checking the adequacy of design, such as by the performance of design reviews, by the use of alternate calculational methods, or by the performance of a suitable testing program; and requires that design changes be subject to design control measures commensurate with those applied to the original plant design, which includes power ascension testing. SRP 14.2.1 specifies that the EPU test program should include steady-state and transient performance testing sufficient to demonstrate that SSCs will perform satisfactorily at the requested power level and that EPU-related modifications have been properly implemented.

The SRP provides guidance to the NRC staff in assessing the adequacy of the licensee's evaluation of the aggregate impact of EPU plant modifications, setpoint adjustments, and parameter changes that could adversely impact the dynamic response of the plant to AOOs.

In this section of the SE, the NRC staff reviewed NMPNS's justification for not performing certain original startup tests against the review criteria established in SRP 14.2.1. NMPNS presented its justification in Section 5.0 of Attachment 7 to the LAR. In Table 5-1, NMPNS presented a detailed cross reference between the guidance of SRP 14.2.1, Paragraph III.C.2, and the discussion in Section 5.1 to address the SRP 14.2.1 review criteria. The NMPNS PATP [[ ]] that would typically be performed during initial startup of a new plant. NMPNS provided a detailed discussion of the basis for [[ ]] pursuant to the staff review criteria established in Section III.C.2 of SRP 14.2.1. The following large transient tests were performed during initial startup as discussed in Section 14.2 of the NMP2 USAR:

- <u>Closure of All MSIVs (Test SUT-25)</u>

  According to Table 14.2-228 of the NMP2 USAR, the objective of the test is to determine the reactor transient behavior that results from the simultaneous full closure of all MSIVs; functionally check the MSIVs for proper operation at selected power levels; and determine isolation valve closure time at rated temperature and pressure resulting from the simultaneous full closure of all MSIVs. NMPNS stated in Table 7-1 of Attachment 7 to the LAR that the test was performed at initial plant startup at 95.3 percent OLTP, and the results demonstrated that analytical methods that predicted the transient were conservative. NMPNS also reported in Section 5.2 of Attachment 7 that all acceptance criteria listed in Table 14.2-228 were satisfied.

- <u>Turbine Trip and Generator Load Rejection (Test SUT-27)</u>

  According to Table 14.2-231 of the NMP2 USAR, the objective of the test is to demonstrate the response of the reactor and its control systems to protective trips in the turbine and generator. NMPNS stated in Table 7-1 of Attachment 7 to the LAR that the test was performed at initial plant startup at 99.6 percent OLTP, and the results demonstrated that analytical methods that predicted the transient were conservative. NMPNS also reported in Section 5.2 of Attachment 7 that all acceptance criteria listed in Table 14.2-231 were satisfied.

<u>Other Industry (BWR) Post-EPU Large Transient Experience</u>

With respect to the review criteria established in SRP Section III.C.2, NMPNS cited post EPU industry experience with transient events that occurred at greater than original power levels at several BWR-3/4/6 plants that are similar in design to NMP2 (BWR-5).

The staff review of the licensee event reports (LERs) associated with these events identified that all systems functioned as expected as a result of the event. However, to further support the staff's basis for concluding that certain power ascension tests do not have to be performed as part of the EPU, the staff included industry experience for Monticello as part of its evaluation.

Edwin I. Hatch Nuclear Plant (BWR-4)

In July 2008, Plant Hatch Unit 1 (BWR-4 with Mark I containment) experienced a turbine trip while operating at 99.7 percent RTP (113 percent OLTP) which initiated a reactor scram as designed. As noted by the staff in LER 2008-003, all required safety systems functioned as expected given the water level and pressure transients caused by both trips. The NRC approved a 113 percent OLTP (2763 MWt) EPU for both units in October 1998. Other events at Units 1 and 2 included a turbine trip and a generator load reject event subsequent to its uprate, as reported in LERs 2000-004 and 2001-002. According to the staff's review of the LERs, the behavior of the primary safety systems was as expected. In LER 2000-004, a turbine trip and reactor scram occurred while operating at 99.7 percent of rated thermal power (2754 MWt) and was caused by the failure of a vibration instrument located on the #10 bearing. The LER reviewed by the staff reported that the event had no adverse impact on nuclear safety. For LER 2001-002, Unit 1 was at 100 percent rated thermal power of 2763 MWt (full EPU approved power level of 113 percent OLTP) at the time of the main turbine trip. In May 1999, Plant Hatch Unit 2 experienced an unplanned event that resulted in a generator load reject from 98.3 percent of uprated power (approx. 112.7 OLTP). The staff review of LER 1999-005 identified that all systems functioned as expected and per their design given the water level and pressure transients caused by the turbine trip and reactor scram.

Brunswick Steam Electric Plant (BWR-4)

Brunswick Unit 2 (BWR 4 with a Mark I containment), licensed by the NRC to 120 percent OLTP (2923 MWt) in May 2002, experienced an unplanned generator and turbine trip on November 4, 2003, which occurred at 115.2 percent OLTP (96 percent of uprated thermal power) and resulted in reactor protection system actuation. As noted by the staff in LER 2003-04, plant systems responded as designed to the transient and the event was fully bounded by the analyses in Chapter 15 of the FSAR.

Dresden Nuclear Power Station (BWR-3)

In July 2006, the Dresden Nuclear Power Station, Unit 2, experienced an MSIV closure while operating at 98 percent (115 percent OLTP) RTP. As noted by the staff in LER 2006-004, all MSIVs closed and the plant experienced a reactor scram as designed, with all systems responding as required. Additionally in January 2004, Unit 3 (BWR 3 with a Mark I containment) experienced an automatic scram due to a main turbine trip from low lube oil pressure while the plant was operating at 97 percent power (113 percent OLTP). As noted by the staff in LER 2004-002, all other system responses were as expected. In December 2001, the NRC approved an EPU for 117 percent OLTP (2957 MWt) for both units.

Monticello Nuclear Generating Plant (BWR-3)

In October 2001, the Monticello Nuclear Generating Plant recorded an MSIV closure event (SCRAM 112) while operating at 1740 MWt (98 percent CLTP; 98 percent of EPU). As noted by the staff in LER 2001-011, the data recorded during the event demonstrated that the plant responded as expected and that the power level for the transient exceeded the percentage power (75 percent OLTP) during initial startup testing in 1971.

The LER also stated that the safety significance of the event was considered to be low based on the operating crew successfully completing the abnormal operating procedure for a reactor scram, including manual run back of the recirculation pumps and restarting a reactor feed pump. Additionally, on January 21, 2002, a generator load rejection event (SCRAM 113) occurred while operating at 1773 MWt (99.9 percent CLTP; 99.9 percent of EPU). As noted by the staff in LER 2002-001, all rods fully inserted, all major plant and substation equipment functioned as designed in response to the scram. In September 1998, the NRC approved an EPU for 106.3 percent OLTP (1775 MWt). In November 2008, Northern States Power Company submitted an EPU LAR for Monticello requesting approval to operate at 2004 MWt (120 percent OLTP). The staff is currently reviewing the LAR.

Clinton Power Station (BWR-6)

In July 2002, the Clinton Power Station tripped from 95 percent (114 percent OLTP) RTP as a result of a faulty main power transformer sudden pressure relay actuation, which initiated a generator trip. The generator trip caused a turbine trip resulting in a reactor scram. As noted by the staff in LER 2002-003, the plant responded normally and as expected with no MSIV closure or safety relief valve lifting during the event. In April 2002, the NRC approved an EPU for 120 percent OLTP (3473 MWt).

NMP2 Plant-Specific Large Transient Experience

Another factor used by NMPNS to justify not performing large transient testing were actual plant transients experienced at NMP2. As documented in Attachment 7 of the LAR, in October 2001, and November 2002, while operating at approximately 104 percent OLTP (100 percent CLTP) power, NMP2 experienced a scram when all MSIVs went closed. NMPNS stated that a review of the plant response compared to the USAR Section 15.2.4 transient analysis for both of these events confirms that they are bounded by the USAR. As noted by the staff in LERs 2001-004 and 2002-004, respectively, the plant responded as expected with all required safety systems available and functioning as designed. In April 1995, the NRC approved a Stretch Power Uprate for NMP2 for 105 percent OLTP (3467 MWt).

In addition to plant-specific experience with MSIV closure resulting from plant transients, the NMP2 PUSAR (Section 2.2.2.) indicates that the generic evaluation for MSIV closure, identified in guidance contained in NRC-approved vendor TR GE ELTR2 (Section 4.7), is bounding and applicable to NMP2. Also, since NMPNS is performing a CPPU without a corresponding pressure increase, and that deliberately closing all MSIVs from 120 percent OLTP will result in an undesirable transient cycle on the primary system that can reduce equipment service life, NMPNS does not recommend performance of an MSIV closure test.

Additionally, in March 1994, April 1999 and August 2003, while operating at 104 percent OLTP (100 percent OLTP for the 1994 event), the plant experienced a generator load rejection event. As noted by the staff in LERs 1994-001, 1999-005 and 2003-002, respectively, the plant responded as expected with all control rods fully inserted following the scram as designed. There were no adverse safety consequences as a result of these events. The staff concurred with NMPNS's conclusions that these events were determined to be bounded by the transient event analysis (Generator Load Rejection with Bypass) as described in NMP2 USAR Section 15.2.2. The staff also noted that the percent increase to CPPU for the August 2003 event was right at the threshold (15 percent above any previously recorded generator load rejection transient) for requiring a new test to be performed as part of the EPU, as recommended by guidance in vendor TR GE LTR ELTR1.

The NRC staff concurs with NMPNS that NMP2 and industry data provide an adequate correlation to allow the effects of the EPU to be analytically determined on a plant-specific basis. Therefore the staff concludes that NMPNS's power ascension and testing program, including their justification [[ ]], provides reasonable assurance that plant SSCs that are affected by the proposed EPU will perform satisfactorily in service at the proposed power uprate level, and that the program complies with the quality assurance requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," including specific review criteria contained in Section III.C. of SRP 14.2.1 and other staff guidance provided in RS-001. Therefore, the proposed power ascension and test plan is acceptable.

2.12.5 <u>SRP 14.2.1, Section III.D, Evaluate the Adequacy of Proposed Transient Testing Plans</u>

This section specifies the guidance and acceptance criteria the licensee should use to include plans for the initial approach to the increased EPU power level and testing that should be used to verify that the reactor plant operates within the values of EPU design parameters. The test plan should assure that the test objectives, test methods, and the acceptance criteria are acceptable and consistent with the design basis for the facility. The predicted testing responses and acceptance criteria should not be developed from values or plant conditions used for conservative evaluations of postulated accidents. During testing, safety related SSCs relied upon during operation shall be verified to be operable in accordance with existing TS and quality assurance program requirements. The following should be identified in the EPU test program:

- The method in which initial approach to the uprated EPU power level is performed in an incremental manner including steady-state power hold points to evaluate plant performance above the original full-power level,

- Appropriate testing and acceptance criteria to ensure that the plant responds within design predictions including development of predicted responses using real or expected values of items such as beginning-of-life core reactivity coefficients, flow rates, pressures, temperatures, response times of equipment, and the actual status of the plant, and

- Contingency plans if the predicted plant response is not obtained, and

A test schedule and sequence to minimize the time untested SSCs important to safety are relied upon during operation above the original licensed full-power level.

The NRC staff reviewed Attachment 7 which provided information about the EPU test plan including startup testing and Attachment 3, "Safety Analysis Report for Nine Mile Point Nuclear Station Unit 2, Constant Pressure Power Uprate," which provided a description of the required testing necessary for the initial power ascension following implementation of the EPU.

The main elements of the PATP include power ascension, monitoring and analysis, and post EPU monitoring. The staff also determined that the licensee adequately addressed post-EPU operating experience for similar designed plants which have previously received an approved

EPU from the NRC. As stated previously, the technical bases for the EPU request follows the guidelines contained in the following staff approved GENE LTRs for EPU safety analysis: NEDC-33004P-A, "Constant Pressure Power Uprate," (CLTR); NEDC-32424P-A, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate," (ELTR1); and NEDC-32523P-A, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR2). PUSAR Section 2.12, "Power Ascension and Testing Plan," submitted with the licensee's application, provides additional information relative to power uprate testing and describes a standard set of tests, which supplement the normal TS testing requirements established for the initial power ascension steps of CPPU. The test schedule would be performed in an incremental manner, with appropriate hold points for evaluation, and contingency plans would be utilized if predicted plant response is not obtained. The staff found that all transient tests described in the initial startup test program were listed in Table 7-1 of Attachment 7 of the LAR, which provided a listing of these tests which were initially performed during initial plant startup. The tests included closure of all MSIVs (SUT-25) at 95.3 percent OLTP and a turbine trip and generator load rejection test (SUT-27) performed at 99.6 percent OLTP. These tests follow the tests described in Attachment 2 of SRP 14.2.1.

The staff has reviewed the licensee's EPU PATP including its conformance with applicable regulations and the staff guidance discussed in SRP 14.2.1. The staff concludes that the proposed EPU test plan will adequately assure that the test objectives, test methods, and test acceptance criteria are consistent with the design basis for the facility.

Conclusion

The NRC staff has reviewed the licensee's EPU power ascension and testing program, including plans for the initial approach to the proposed maximum licensed thermal power level, transient testing necessary to demonstrate that plant equipment will perform satisfactorily at the proposed increased maximum licensed thermal power level, and the test program's conformance with applicable regulations. The review included an evaluation of the licensee's plans for the initial approach to the proposed maximum licensed thermal power level, including verification of adequate plant performance, and the test program's conformance with applicable regulations. NMPNS's test program primarily includes steady state testing with no large transient testing proposed. The staff also reviewed the licensee's justification for not performing large transient testing as discussed in Attachment 7 of the LAR. The staff evaluation of the licensee's justification was found to be acceptable based on the applicable review criteria discussed in Section III.C.2 of SRP 14.2.1.

Based on the NRC staff's review of the licensee's power ascension and test program, the staff concludes that the proposed EPU test program provides adequate assurance that the plant will operate as expected and in accordance with design criteria and that SSCs affected by the proposed EPU, or modified to support the proposed power increase, will perform satisfactorily in service. Further, the staff finds that there is reasonable assurance that the EPU testing program satisfies the requirements of 10 CFR Part 50, Appendix B, Criterion XI, "Test Control," and the staff guidance and review criteria in SRP 14.2.1. Therefore, the NRC staff finds the proposed EPU acceptable with respect to the power ascension and test program.

2.13 Risk Evaluation

Regulatory Evaluation

The licensee did not request the relaxation of any deterministic requirements for their proposed power uprate, and the staff's approval is primarily based on the licensee meeting the current deterministic engineering requirements. Per Review Standard RS-001, Section 13, (Reference 16), a risk evaluation is conducted to determine if "special circumstances" are created by the proposed power uprate (EPU). As described in Appendix D of Standard Review Plan (SRP) Chapter 19.2 (Reference 48), special circumstances are any issues that would potentially rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements. Specific review guidance is contained in Matrix 13 of Review Standards RS-001 and its attachments. Further guidance on how to make a determination of special circumstances is provided in Appendix D to SRP Chapter 19.2.

The staff's review addresses the risk associated with operating at the proposed EPU conditions in terms of changes in core damage frequency (CDF) and large early release frequency (LERF) from internal events, external events, and shutdown operations. In addition, the staff's review addresses the quality of the risk analyses used by the licensee to support the application for the proposed EPU. This includes a review of licensee actions to address issues or weaknesses that may have been raised in previous staff reviews of the licensee's individual plant examination (IPE), individual plant examinations of external events (IPEEE), or by industry peer reviews. The staff used the guidance provided in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," (Reference 49) to focus the review of this non-risk-informed submittal.

Technical Evaluation

The NRC staff reviewed the risk evaluation submitted for NMP2 by NMPNS, as supplemented by responses to the staff's RAI (Reference 15). The licensee has provided an estimate of the increase in risk, CDF and LERF, assuming EPU conditions. A combination of quantitative and qualitative methods was used to assess the risk impact of the proposed EPU. The following sections provide the staff's technical evaluation of the risk information provided by the licensee. The staff's evaluation did not involve an in-depth review of the licensee's risk evaluation.

2.13.1 Probabilistic Risk Assessment (PRA) Model Quality

The quality of the licensee's PRA used to support a license application needs to be commensurate with the role the PRA results play in the decision-making process. The staff's approval is based on the licensee meeting the current deterministic requirements, with the risk assessment providing confirmatory insights and ensuring that the EPU creates no new vulnerabilities.

2.13.1.1 IPE / IPEEE

The licensee submitted the NMP2 Individual Plant Examination (IPE), which is based on a full scope level 2 PRA performed in fulfillment of Generic Letter 88-20 (Reference 50). The NRC issued an SE stating that the licensee did not identify any severe accident vulnerabilities associated with either core damage or containment failure. The IPE submittal identified changes to the plant, procedures, and training as part of the IPE process and the licensee stated in their RAI response that these changes were dispositioned and addressed in the updated PRA for the EPU risk analysis.

The NRC staff noted that an element identified in the IPE relating to EPU assessment was addressed appropriately. Procedure changes were implemented, after the EPU License Amendment Request (LAR), to have operations open Emergency Core Cooling System (ECCS) pump room doors to facilitate natural cooling upon a loss of Service Water. Therefore, there is additional margin for a loss of Service Water initiating event that is not credited in the PRA model used to evaluate EPU.

Based on NRC staff review of dispositions of topics outstanding from the IPE assessment, the staff concludes all items have been addressed appropriately and, therefore, do not impact the EPU risk assessment.

The licensee submitted the NMP2 Individual Plant External Events Examination (IPEEE) to the NRC in response to Supplement 4 of GL 88-20 (Reference 51). The NRC issued an SE that concluded that the licensee's IPEEE identifies most likely severe accidents and severe accident vulnerabilities from external events.

Two of the findings related to external flooding and seismic hazard truncation were dispositioned by assuming conservative assumptions and as having no or negligible impact on important event sequences and equipment relative to the proposed EPU.

Based on NRC staff review, the staff concludes the licensee has adequately addressed all items related to IPEEE and therefore does not impact the EPU risk assessment.

2.13.1.2 Peer Review of the NMP2 PRA

The submittal states that the NMP2 internal events PRA received a formal industry BWROG peer review in 1997. The peer review team used the BWROG peer review certification process. This certification process was developed to establish a method of assuring the technical quality of the PRA for a spectrum of potential uses. The licensee stated that no findings (i.e., findings that are extremely important and necessary to address the technical adequacy of the PRA) were found by the review team. The NMP2 PRA is currently in the process of a major update to conform to the ASME PRA Standard and RG 1.200. Thus, the PRA used for this application predates the present PRA update effort to meet ASME Capability Category II PRA quality.

The peer review process identified the possible inclusion of Break Outside Containment (BOC) as an initiator in the NMP2 PRA. In response to RAI, the licensee concluded that Feedwater and main steam system high energy line breaks outside containment which are currently modeled contributed less than 1E-8/yr CDF and 1E-9/yr LERF, therefore, BOC would result in less than 1E-9/yr contribution to CDF.

The EPU increases the probability of stuck open relief valve (SORV) openings, therefore, the NRC staff requested additional information concerning a peer review element that stated the probability for the need to open a SORV was not modeled for various transient initiators. The licensee, in its response to RAI, explained that the probability of a stuck open SRV due to transient initiating events was added to the inadvertent open relief valve (IORV) initiating event in the NMP2 PRA. Furthermore, the licensee provided an example for the quantification of a transient induced medium LOCA due to a stuck open SRV.

2.13.1.3 Conclusions Regarding the Quality of the NMP2 PRA

The NRC staff's evaluation of the licensee's submittal focused on the capability of the licensee's PRA and other risk evaluations (e.g., for external events) to analyze the risks stemming from pre- and post-EPU plant operations and conditions. The NRC staff's evaluation did not involve an in-depth review of the licensee's PRA; instead, it involved an evaluation of the information provided by the licensee in its submittal, as supplemented by its RAI responses; considered the review findings for the NMP2 IPE and IPEEE; and reviewed the BWROG peer review open F&Os and their dispositions for this application.

Based on its evaluation, the NRC staff finds that the NMP2 PRA models used to support the risk evaluation for this application have sufficient scope, level of detail, and technical adequacy to support the evaluation of the EPU.

2.13.2 Internal Events Risk Evaluation

The licensee assessed the risk impacts from internal events resulting from the proposed EPU by reviewing the changes in plant design and operations resulting from the proposed EPU, mapping these changes onto appropriate PRA elements, modifying affected PRA elements as needed to capture the risk impacts of the proposed EPU, and requantifying the NMP2 PRA to determine the CDF and LERF of the post-EPU plant.

2.13.2.1 Initiating Event Frequencies

The NMP2 PRA model includes initiating event categories which includes transient initiating events, LOCA initiators, and internal flooding initiators. The initiating event frequencies were not changed for the EPU risk assessment.

Transients – The licensee stated that the evaluation of the plant conditions and procedural changes for EPU conditions do not result in any new transient initiators, nor directly impact transient initiator frequencies significantly. Sensitivity calculations were performed that increased the nonisolation transient initiator frequency to bound the various changes to the balance-of-plant (BOP) side of the plant.

Loss of Offsite Power (LOOP) – EPU operating margins for main generator step-up transformers will be reduced from 9 percent to 3 percent. Although margins are reduced under anticipated EPU operating conditions, the licensee states in response to an RAI question, that it does not expect a change in LOOP initiating event frequency nor electrical reliability due to EPU since the transformers will be maintained and operated within their ratings.

Support System – The licensee states that no significant changes to support systems are planned in support of the EPU and no significant impact on support system initiating event frequencies due to the EPU are postulated.

Loss of Coolant (LOCA) – The licensee did not identify any impact on LOCA frequencies resulting from the EPU. However, the licensee did acknowledge that increased reactor energy for the EPU could result in LOCA frequency increases. A sensitivity calculation increased the LOCA initiating event frequency by ten percent for a combined large-medium and small-break LOCA. The results show a very small increase in risk.

Internal Flooding – Since major piping changes are not required for EPU except in the secondary plant in the Turbine Building and flow accelerated corrosion rates are not expected to be significant, the internal flooding frequencies remain unchanged.

Overall EPU Impact on Initiating Events

The staff finds the licensee adequately addressed internal initiating event frequencies based on the licensee properly implementing the equipment modifications and replacements it identified in its license amendment submittal. Furthermore, based on the licensee's sensitivity calculation, any short-term risk impact from break-in failures caused by the numerous BOP equipment changes is expected to be very small. Finally, the staff notes that any changes observed in the future in initiating event frequencies will be identified and tracked under the plant's existing performance monitoring programs and processes and will be reflected in future updates of the PRA, based on actual plant operating experience.

The NRC staff has not identified any issues associated with the licensee's evaluation of internal initiating event frequencies that would significantly alter the overall risk results or conclusions for this license amendment. Therefore, the staff concludes that there are no issues with the evaluation of internal initiating event frequencies associated with the NMP2 internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that initiating event frequencies will not change as a result of the EPU.

2.13.2.2 Component Failure Rates

The licensee concluded in its submittal that the EPU would not significantly impact long-term equipment reliability due to the replacement/modification of plant components. The majority of hardware changes in support of the EPU may be characterized as either replacement of components or upgrade of existing components. The licensee described no planned operational modifications as part of the EPU that involve operating equipment beyond design ratings.

The NRC staff finds that the licensee adequately addressed equipment reliability based on the licensee properly implementing the equipment modifications and replacements it identified in its license amendment submittal. Further, any short-term risk impact of the numerous BOP equipment changes, due to break-in failures, is expected to be very small. Finally, the NRC staff notes that the licensee's component monitoring programs, including equipment modifications and/or replacement are being relied upon to maintain the current reliability of the equipment. In addition, the NRC staff has not identified any issues associated with licensee's evaluation of component reliability that would significantly alter the overall results or conclusions for this license amendment. Therefore, the staff concludes that there are no issues with component reliabilities/failure rates modeled in the NMP2 internal events PRA.

2.13.2.3 Accident Sequence Delineation and Success Criteria

The licensee evaluated the impact of the proposed EPU on PRA accident sequence delineation and success criteria. The PRA success criteria are affected by the increased boil off rate, the increased heat load to the suppression pool, and the increase in containment pressure and temperature. The response to an initiator is represented in the PRA models by a set of discrete requirements for the operation of individual systems and the performance of specific operator actions. These scenario-specific requirements define the success criteria for system operation and operator action to fulfill the critical safety functions necessary to maintain the reactor fuel in a safe condition. The licensee assessed the critical safety functions of reactivity control, reactor pressure vessel (RPV) pressure control, containment heat removal, depressurization, and reactor pressure vessel inventory makeup at EPU conditions using the Modular Accident Analysis Program (MAAP) thermal hydraulic computer code. The impact on success criteria and accident sequence delineation was compared to the pre-EPU conditions as modeled in the PRA model.

In response to an RAI question, the licensee noted that the failure of two or more SRVs, including contribution from common cause failure, is assumed to be bounded by large-break LOCA in the NMP2 PRA. The LOCA sensitivity analysis provided in the submittal is assumed to subsume the contribution of multiple SRVs failing open. The total probability of a stuck open SRV was increased by 10 percent based on estimated number of challenges.

The pressure following a plant trip with an ATWS post-EPU will increase, however the number of open SRVs is not expected to change. This is because the short-term transient response shows the total relief valve flow increase (at EPU conditions) is about 6 percent of the current licensed thermal power rated steam flow. Given the small increase in relief flow, only sixteen SRVs are required for EPU, same as pre-EPU. Since pre- and post-EPU require the same number of SRVs for ATWS mitigation, the success criteria remains unchanged.

The PRA success criteria for RPV makeup remain the same for the post-EPU configuration. The licensee stated that both high pressure (HP) and low pressure (LP) injection systems have more than adequate flow margin for the post-EPU configuration.

The licensee stated that no EOP changes and no special or new requirements for operator actions pertain to this PRA success criterion adjustment for the EPU. Timing changes have been identified for the level 1 PRA and can impact HEPs for operator actions. This change has been factored into revised HEP values for EPU conditions as described in the section on HRA.

The licensee noted a negligible impact on the level 2 PRA safety functions and results and concluded that no changes to the success criteria have been identified with regard to the level 2 containment evaluation.

Overall EPU Impact on Accident Sequence Delineation and Success Criteria

The staff agrees that the EPU does not change the plant configuration or operation in a manner that results in changes to existing accident sequence modeling and success criteria made to reflect the post-EPU plants.

2.13.2.4 Operator Actions and LOOP Recovery

Human Reliability Analysis – EPU has the general effect of reducing the time available for the operators to complete recovery actions, because of the higher decay heat level after EPU implementation. NMP2 has no new operator actions or operator workarounds created as a result of the EPU.

The licensee stated in its submittal that the NMP2 is dependent on the operating crew actions for successful accident mitigation. The success of these actions is, in turn, dependent on a number of performance-shaping factors and that the performance-shaping factor that is principally influenced by the EPU is the time available within which to detect, diagnose, and perform required actions. The higher power level results in reduced times available for some operator actions.

MAAP calculations were performed for the pre- and post-EPU configurations to determine the change in allowable operator action timing. To minimize the resources required to requantify all operator actions in the PRA due to the EPU, a screening process was performed to identify those operator actions that have an impact on the PRA results. The operator actions identified for explicit review were selected based on Fussell Vesely (F-V) and Risk Achievement Worth (RAW). F-V is defined as the fractional decrease in CDF when the plant feature is assumed perfectly reliable and available. RAW is defined as the increase in risk if the feature is assumed to be failed at all times. The operator actions identified for explicit review were selected based on the following criteria:

1. F-V > 0.005
2. RAW > 2.0
3. Operations actions required to perform within thirty minutes

The licensee submittal evaluated the impact of the power-level increase for 45 operator actions. In response to an RAI question (letter dated February 19, 2010 (ML100550599)), the licensee provided analysis for an additional 11 operator actions. The licensee stated that given the significant HEPs modified for this study results in increasing the plant risk profile by about 5 percent, the non-significant HEPs, if adjusted, would be expected to impact the risk profile by a fraction of a percent.

For operator actions that the licensee identified as having the potential to be significantly impacted by the EPU, a detailed HRA was performed. The HRA for EPU was performed using the Electric Power Research Institute (EPRI) HRA Calculator software. Actions that did not require alteration for EPU conditions were left at their baseline values.

Knowledge of the context surrounding each of the modeled operator actions (e.g., the sequences that are addressed and the additional equipment failures that have occurred) is important to ensure that the correct HEPs have been assigned. The staff agrees with the licensee's conclusion that the main impact of the proposed EPU on the post-initiator operator actions is the reduction in time available for the plant operators to detect, diagnose, and perform required actions.

The licensee's use of thermal hydraulic analyses and knowledge of equipment capacities to determine the change in the time available for diagnosis and decision-making for the post-initiator operator actions is consistent with good PRA practices. The staff observes that the apparent small changes in available times, and the corresponding changes in the post-initiator HEP values, should not be taken literally since the parameters and models used to obtain them are uncertain. However, the staff considers the licensee's analysis as adequate to conclude that the change in post-initiator HEP values due to the EPU is small.

The licensee stated that Emergency Operating Procedures (EOP) and Special Operating Procedures (SOP) impacts due to EPU are minimal. All EOP and SOP impacts have been identified, and the changes are limited to figures; therefore, the PRA results are only minimally impacted. Actual EOP and SOP actions performed by operators are not changed.

Overall EPU Impact on Operator Actions

Based on the licensee's submitted information, the NRC staff finds that it is reasonable to expect that the main impact of the EPU is to reduce the time available for some operator actions, which will increase the associated HEPs. However, these increased HEPs are not expected to create significant impacts, unless a number of critical operator actions cannot be performed at the increased power levels. The NRC staff has not identified any issues associated with the licensee's evaluation of operator actions that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the operator actions evaluation associated with the NMP2 internal events PRA that would rebut the presumption of adequate protection or warrant denial of this license amendment.

2.13.2.5 Internal Events Risk Results

Table 1: Internal Events CDF and LERF Risk Metrics

	Pre-EPU	Post-EPU	Delta Change	Percent increase
CDF	$1.44x10^{-5}$/year	$1.51x10^{-5}$/year	$7.4x10^{-7}$	5.1
LERF	$5.67x10^{-7}$/year	$5.79x10^{-7}$/year	$1.2x10^{-8}$	2.1

The increases in internal events CDF and LERF shown above are within the RG 1.174 acceptance guidelines for being "very small," and, therefore, do not raise concerns of adequate protection.

Level 2 PRA calculates the containment response under postulated severe accident conditions and provides an assessment of the containment adequacy. The licensee states and the staff concurs that the EPU change in power represents a relatively small change to the overall challenge to containment under severe accident conditions.

The NRC staff finds the licensee's evaluation of the impact of the proposed EPU on at-power risk from internal events is reasonable and concludes that the base risk due to the proposed EPU is acceptable and that there are no issues that rebut the presumption of adequate protection provided by the licensee meeting the currently specified regulatory requirements.

2.13.3 External Events Risk Evaluation

The licensee does not have fire or seismic PRA models. The IPEEE studies used the Electric Power Research Institute (EPRI) Fire Induced Vulnerability Evaluation (FIVE) methodology and EPRI Seismic Margins methodology to address external risk from these sources. High winds, external flooding, and other external events (e.g., transportation and nearby facility accidents) were addressed by reviewing the plant environs against regulatory requirements. The licensee provided a qualitative assessment of the impact of EPU implementation on external event risk, which is discussed below.

2.13.3.1 Internal Fire Risk

For the IPEEE fire analysis, NMP2 performed a fire-induced vulnerability evaluation (FIVE) methodology. The IPEEE staff evaluation notes the licensee analyzed all fire areas and compartments using a reasonable screening methodology. Fire initiating events from the IPEEE are incorporated into the NMP2 PRA model.

In response to RAI, NMP2 stated that human reliability was evaluated for response to fires inside the control room, and also in the case of abandonment of the control room. These actions are associated with Reactor Pressure Vessel (RPV) blow down when high pressure injection systems are unavailable. As a result of the EPU, these actions now have a response margin of less than 35 minutes prior to core damage verses less than 40 minutes pre-EPU. The most impacted action is operator recovery from fire in the control room using the Remote Shutdown Panel. The design basis analysis was revised for EPU and takes credit for a peak fuel clad temperature of < 1500F, instead of requiring RPV water level to remain above top of active fuel (TAF). With this change in acceptance criteria, the maximum operator action time to initiate depressurization from the remote shutdown panel was increased from 10 to 13.4 minutes. NMP2 stated that although the post-EPU conditions lead to an RPV water level reaching TAF in a shorter time frame, the impact on fuel temperature is small and does not approach the 1500 °F design basis limit. HEP for this action increased from 1.2E-2 to 4.4E-2.

Fire frequencies and fire mitigation are not related to reactor power level, therefore, the NRC staff does not expect the post-EPU risk increase due to fire to exceed RG 1.174 guidelines and create the "special circumstances" described in Appendix D of SRP Chapter 19.2 for a non risk-informed application.

2.13.3.2 Seismic Risk

For seismic events, NMP2 is designed to a seismic acceleration level of 0.15g peak ground acceleration (PGA) anchored to a Regulatory Guide 1.60 spectral shape. NMP2 performed an EPRI seismic margins assessment (SMA) using a review level earthquake of 0.5g for screening in its seismic IPEEE.

In response to an RAI question, the licensee stated that seismic margins have decreased, but they are still within code allowable and do not impact the seismic qualification of equipment; therefore, the reduced margins do not impact assumptions considered in the NMP2 SMA. The licensee also noted that NMPNS design and configuration control process includes notifying the structural engineering and PRA groups of the proposed design and to request a design input/impact assessment for seismic and PRA impact.

The staff finds the licensee's evaluation of the impact of the proposed EPU on at-power risk from seismic events is reasonable, given that EPU modifications do not affect the structures or component anchoring, and that no new vulnerabilities to a seismic event are introduced by implementation of the EPU.

2.13.3.3 Other External Events Risk

The NMP2 IPEEE addresses events other than seismic and fires, including high winds/tornadoes, external floods, and transportation and nearby facility accidents. Consistent with the IPEEE guidance, the licensee reviewed the plant environs against regulatory requirements regarding these hazards and concluded that NMP2 meets the applicable NRC SRP requirements and, therefore, has an acceptably low risk with respect to these hazards.

2.13.3.4 External Events Risk Conclusion

The staff has not identified any issues associated with the licensee's evaluation of the risks related to external events that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the external events risk evaluation that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that the risk impact from external events resulting from the proposed EPU will be very small, based on the licensee's current risk evaluations.

2.13.4 Shutdown Risk Evaluation

The primary impact of the EPU on risk during shutdown operations is associated with the decrease in allowable operator action times in response to events. The licensee stated that the reductions are on the order of 14 percent 1 day after shutdown. However, the licensee stated that these allowable operator action times to respond to loss of heat removal scenarios during shutdown operations are many hours long, and such small changes in response times result in negligible changes in HEPs.

The aspects of shutdown risk that the licensee identified as being impacted by EPU conditions included greater decay heat generation, longer times to shutdown, longer times before alternate Decay Heat Removal (DHR) systems can be used, shorter times to boiling, and shorter times for operator responses. All of these aspects result from the increased decay heat generation created by the EPU.

The increased power level decreases the boildown time. However, because the reactor is already shut down, the boildown times are relatively long compared to the at-power PRA. The licensee stated that, at 1 day into an outage with the RPV level at the flange, the time to core uncovery for EPU conditions is 8.3 hours compared to 9.6 hours pre-EPU. These changes in timing are expected to have a negligible impact on operator responses and associated HEPs.

The increased decay heat loads associated with the EPU do not affect the success criteria for the systems normally used to remove decay heat, but the licensee stated that the EPU does impact the time when low-capacity DHR systems can be considered successful alternate DHR systems.

Other success criteria are stated as being marginally impacted by the EPU. The EPU has a minor impact on shutdown RPV inventory makeup during loss of DHR scenarios in shutdown because of the low decay heat level. The heat load to the suppression pool during loss of DHR scenarios is also lower than at power because of the low decay heat level, such that the margins for the suppression pool cooling capacity are adequate for EPU conditions. The licensee stated that the impact of the EPU on the success criteria for blowdown loads, RPV overpressure margin, and SRV actuation is negligible because of the low RPV pressure and low decay heat level during shutdown.

Procedural controls are in place to ensure the risk impacts of EPU on shutdown operations are not significant and defense-in-depth strategies are implemented to assure structures, systems, and components that perform key safety functions are available when needed.

The staff has not identified any issues associated with the licensee's evaluation of shutdown risks that would significantly alter the overall results or conclusions for this license amendment. Therefore, the NRC staff concludes that there are no issues with the shutdown operations risk evaluation that would rebut the presumption of adequate protection or warrant denial of this license amendment. The expectation is that the impact on shutdown risk resulting from the proposed EPU will be negligibly small, based on the licensee's current shutdown risk management process.

2.13.5 Risk Evaluation Conclusions

The NRC staff concludes that there are no issues with the licensee's risk evaluation for the proposed EPU that would create the "special circumstances" described in Appendix D of SRP Chapter 19. Therefore, the NRC staff finds the risk implications of the proposed EPU acceptable.

3.0 FACILITY OPERATING LICENSE AND TECHNICAL SPECIFICATION CHANGES

To achieve the EPU, the licensee proposed the changes described below to the facility operating license and TSs for NMP2.

3.1 Operating License Changes

a. Under License Condition 2.C.(1), the licensee proposed to change the maximum reactor core power level from 3467 MWt to 3988 MWt.

The licensee proposed to change the steady-state reactor core power level from 3467 MWt to 3988 MWt. The change reflects the actual value in the proposed application and is consistent with the results of the licensee's supporting safety analyses. The NRC staff finds this proposed change acceptable.

b. Under License Condition 2.C.(7), the licensee proposed to change the value of feedwater temperature at steady-state conditions from 405 °F to 420.5 °F.

Operating License Section 2.C.(7), "Operation with Reduced Feedwater Temperature (Section 15.1, SSER 4)," currently states NMP2 shall not be operated with a feedwater heating capacity less than that required to produce a feedwater temperature of 405 °F at steady-state conditions unless analyses supporting such operations are submitted by NMPNS and approved by the staff. The licensee proposed to change this value from 405 °F to 420.5 °F. Specifically, the TS value of minimum feedwater temperature allowed during rated steady-state conditions would be increased by the same amount as the feedwater temperature used in the heat balance in order to maintain the same margin to the original basis. The feedwater temperature used in the heat balance was changed from 425.1 °F to 440.5 °F; therefore, the licensee proposed to change the TS value in Section 2.C.(7) from 405 °F to 420.5 °F. The change is consistent with the results of the licensee's supporting safety analyses. The NRC staff finds this proposed change acceptable.

3.2 Technical Specification Changes

a. TS Section 1.1, Definitions - Rated Thermal Power

Rated thermal power is defined as the total reactor core heat transfer rate to the reactor coolant (i.e., 3467 MWt). The licensee proposed to change the stated CLTP value of 3467 MWt to 3988 MWt consistent with License Condition 2.C.(1). The change reflects the actual value in the proposed application and is consistent with the results of the licensee's supporting safety analyses. The NRC staff finds this proposed change acceptable.

b. TS Section 2.1.1, Reactor Core Safety Limits (SLs)

TS Section 2.1.1.1 currently states that with the reactor steam dome pressure < 785 psig or core flow < 10 percent rated core flow, Thermal Power shall be ≤ 25 percent RTP. The licensee proposed to change the stated RTP percentage from ≤ 25 percent RTP to ≤ 23 percent RTP.

The licensee states in Reference 1 that the historical 25 percent of RTP value for the TS Safety Limit, some thermal limits monitoring LCO thresholds, and some SR thresholds are based on generic analyses (evaluated up to ~50 percent of original RTP) applicable to the plant design with highest average bundle power for all of the BWR product lines. As originally licensed, the highest average bundle power (at 100 percent RTP) for any BWR6 is 4.8 MWt/bundle. As described in the NMP2 TSs, the 25 percent RTP value is a conservative basis; however, this percent value should be reduced when any plant is uprated such that at 100 percent of uprated power the average bundle power is greater than the original generic basis of 4.8 MWt/bundle. Therefore, to maintain the same basis with respect to absolute thermal power, if the uprated average bundle power is > 4.8 MWt/bundle, then the percent RTP value is revised to equal (25 percent * 4.8 MWt/bundle * # of bundles / total uprated MWt). For the proposed NMP2 EPU, the average bundle power is > 4.8 MWt/bundle. Therefore, the licensee proposed to change the Safety Limit percent RTP basis from 25 percent RTP to 23 percent RTP. The thermal limits monitoring LCO and SR percent RTP thresholds change from 25 percent to 23 percent RTP are also applicable to this basis. As discussed in SE Section 2.8.2, the NRC staff finds that the licensee has provided adequate information to support their determination of the fuel thermal margin monitoring threshold, as rescaled to NMP2's EPU conditions. On this basis, the NRC staff finds the thermal limits monitoring threshold rescaling acceptable.

c. TS Section 3.1.7, Standby Liquid Control (SLC) System

TS Section 3.1.7, SLC System, Surveillance Requirement (SR) 3.1.7.7, currently requires verification that each pump develop a flow rate ≥ 41.2 gpm at a discharge pressure of ≥ 1325 psig. The licensee proposed to change the stated discharge pressure from ≥ 1325 psig to ≥ 1327 psig.

As discussed in SE Section 2.8.4.5, the NRC staff reviewed the licensee's analyses related to the effects of the proposed EPU on the SLCS and concludes that the licensee has adequately accounted for the effects of the proposed EPU on the system and demonstrated that the system will continue to provide the function of reactivity control independent of the control rod system following implementation of the proposed EPU. On this basis, the NRC staff finds the change to the stated discharge pressure from ≥ 1325 psig to ≥ 1327 psig acceptable.

d. TS Section 3.2.1, Average Planar Linear Heat Generation Rate (APLHGR)

TS Section 3.2.1, APLHGR Applicability, Actions, and Surveillance Requirements are dependent on a percentage of RTP (i.e., 25 percent RTP). The licensee proposed to change the stated RTP percentage from 25 percent RTP to 23 percent RTP. The basis for this change is the same as discussed in SE Section 3.2.b. above. Therefore, the NRC staff finds the proposed change acceptable.

e. TS Section 3.2.2, Minimum Critical Power Ratio (MCPR)

TS Section 3.2.2, MCPR Applicability, Actions, and Surveillance Requirements are dependent on a percentage of RTP (i.e., 25 percent RTP). The licensee proposed to change the stated RTP percentage from 25 percent RTP to 23 percent RTP. The basis for this change is the same as discussed in SE Section 3.2.b. above. Therefore, the NRC staff finds the proposed change acceptable.

f. TS Section 3.2.3, Linear Heat Generation Rate (LHGR)

TS Section 3.2.3, LHGR Applicability, Actions, and Surveillance Requirements are dependent on a percentage of RTP (i.e., 25 percent RTP). The licensee proposed to change the stated RTP percentage from 25 percent RTP to 23 percent RTP. The basis for this change is the same as discussed in SE Section 3.2.b. above. Therefore, the NRC staff finds the proposed change acceptable.

g. TS Section 3.3.1.1, Reactor Protection System (RPS) Instrumentation

The licensee stated in Reference 1 that the following RPS Instrumentation Actions and Surveillance Requirements contained in TS Section 3.3.1.1, including Table 3.3.1.1-1, are dependent on a percentage of RTP and proposed the following changes:

Required Action E.1, which requires that Thermal Power be reduced to < 30 percent RTP, will be revised to require that Thermal Power be reduced to < 26 percent RTP.

The threshold for performing SR 3.3.1.1.3 (and associated Note) will be revised from ≥ 25 percent RTP to ≥ 23 percent RTP.

The threshold for performing SR 3.3.1.1.15, Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions, will be revised from ≥ 30 percent RTP to ≥ 26 percent RTP.

The threshold for performing SR 3.3.1.1.16, Average Power Range Monitor (APRM) Oscillation Power Range Monitor (OPRM)-Upscale Function, will be revised from ≥ 30 percent RTP to ≥ 26 percent RTP.

Table 3.3.1.1-1, Function 2.b, Flow Biased Simulated Thermal Power-Upscale, contains both a flow-biased Allowable Value (AV) (≤ 0.64W + 63.8 percent RTP) and a fixed AV clamped at 115.5 percent RTP. The flow-biased AV will be changed to (≤ 0.55W + 60.5 percent RTP). Note (b) modifies the Function 2.b AV when reset for single loop operation per Limiting Condition for Operation (LCO) 3.4.1, Recirculation Loops Operating. Note (b) will be revised to a value of 0.50(W – 5 percent) + 53.5 percent RTP, where W = Recirculation Drive Flow in percent of Rated Flow.

Table 3.3.1.1-1, Function 8, Turbine Stop Valve-Closure and Function 9, Turbine Control Valve Fast Closure, Trip Oil Pressure-Low, both specify an Applicable Mode or other Specified Conditions of ≥ 30 percent RTP. The ≥ 30 percent RTP value will be revised to ≥ 26 percent RTP.

In addition, the licensee proposed the following notes to be added to the Table 3.3.1.1-1 calibration surveillance requirements for the Flow Biased Simulated Thermal Power – Upscale function:

1. If the As-Found channel setpoint is outside its predefined as-found tolerances, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

2. The instrument channel setpoint shall be reset to a value that is within the As-Left tolerance around the nominal trip setpoint at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the nominal trip setpoint are acceptable provided that the As-Found and As-Left tolerances apply to the actual setpoint implemented in the surveillance procedures to confirm channel performance. The nominal trip setpoint and the methodologies used to determine the As-Found and the As-Left tolerances are specified in the Bases associated with the specified function.

As discussed in SE Section 2.4.3, the NRC staff has reviewed the proposed changes to TS 3.3.11 and found they follow previously approved GE Nuclear Energy Licensing TR NEDC-33004P-A, Licensing TR Constant Pressure Power Uprate, Revision 4, to revise the trip point lower by the ratio of the current licensed thermal power to the proposed uprate power. The proposed TS changes associated with reactor core safety limit and related settings are not changed by a ratio of CLTP to proposed extended power uprate. They are changed according to an alternate method used when power exceeds 4.8 MWt/bundle. The proposed value of 23 percent is acceptable to the NRC staff. Based on the guidelines in Section F.4.2.3 of General Electric Licensing TR NEDC-32424P-A, the Turbine Stop Valve (TSV) Closure and Turbine Control Valve (TCV) Fast Closure Scram and RPT Bypass analytical limit in percent RTP is reduced by the ratio of the power increase. The new analytical limit does not change with respect to absolute thermal power. Because the trip does not change in terms of absolute power, there is no effect on the transient response. Based on the above, the NRC staff finds the proposed changes to TS 3.3.1.1 are acceptable.

h. TS Section 3.3.2.2, Feedwater System and Main Turbine High Water Level Trip Instrumentation

TS Section 3.3.2.2, Feedwater System and Main Turbine High Water Level Trip Instrumentation Applicability and Required Action C.2 are dependent on a percentage of RTP (i.e., 25 percent RTP). The licensee proposed to change the stated RTP percentage from 25 percent RTP to 23 percent RTP. The basis for this change is the same as discussed in SE Section 3.2.b. above. Therefore, the NRC staff finds the proposed change acceptable.

i. TS Section 3.3.4.1, End of Cycle Recirculation Pump Trip (EOC - RPT) Instrumentation

TS Section 3.3.4.1, End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation Applicability, Actions, and Surveillance Requirements are dependent on a percentage of RTP (i.e., 30 percent RTP). The licensee proposed to change the stated RTP percentage from 30 percent RTP to 26 percent RTP. The NRC staff finds the proposed change acceptable.

j. TS Table 3.3.6.1-1, Primary Containment Isolation Instrumentation

TS Table 3.3.6.1-1, Primary Containment Isolation Instrumentation, Function 1.c, Main Steam Line (MSL) Flow - High, specifies an AV of ≤ 122.8 psid. The licensee proposed to change the stated AV from ≤ 122.8 psid to ≤ 184.4 psid.

As discussed in SE Section 2.4.3, the NRC staff has reviewed the proposed changes to TS 3.3.6.1-1 and find that the licensee followed previously approved GE Nuclear Energy Licensing TR NEDC-33004P-A, Licensing TR Constant Pressure Power Uprate, Revision 4, and applies an acceptable methodology (response E1 and E2 of Reference 3) for calculating the AV. Therefore, the NRC staff finds the proposed change to the stated AV from ≤ 122.8 psid to ≤ 184.4 psid acceptable.

k. TS Section 3.4.3, Jet Pumps

TS Section 3.4.3. Jet Pumps, SR 3.4.3.1, Note 2, indicates that the surveillance is not required to be performed until 24 hours after > 25 percent RTP. The licensee proposed to change the stated RTP percentage from 25 percent RTP to 23 percent RTP. The basis for this change is the same as discussed in SE Section 3.2.b. above. Therefore, the NRC staff finds the proposed change acceptable.

l. TS Section 3.7.5, Main Turbine Bypass System

TS Section 3.7.5, Main Turbine Bypass System, Applicability and Actions, are both dependent on a percentage of RTP (i.e., 25 percent RTP). The licensee proposed to change the stated RTP percentage from 25 percent RTP to 23 percent RTP. The basis for this change is the same as discussed in SE Section 3.2.b. above. Therefore, the NRC staff finds the proposed change acceptable.

3.3 Technical Specification Bases Changes

The licensee provided proposed changes to clarify the TS Bases and to reflect the changes being made to the associated TSs. The proposed TS Bases changes are being made by the licensee in accordance with the licensees TS Section 5.5.10, "Technical Specifications (TS) Bases Control Program."

3.4 License Conditions on Potential Adverse Flow Effects

3.4.1 Steam Dryer

These license conditions provide for monitoring, evaluating, and taking prompt action in response to potential adverse flow effects as a result of power uprate operation on plant structures, systems, and components (including verifying the continued structural integrity of the steam dryer) for power ascension from current licensed thermal power (CLTP) (3467 MWt) to 120 percent original licensed thermal power (OLTP or 115 percent of CLTP) (3988 MWt) condition.

1. The following requirements are placed on operation of the facility above the thermal power level of 3467 MWt for the power ascension from CLTP (3467 MWt):

   a. NMPNS shall monitor the main steam line (MSL) strain gauges during power ascension above 3467 MWt for increasing pressure fluctuations in the steam lines. While first increasing power above 3467 MWt, NMPNS shall collect data from the MSL strain gauges at nominal 1 percent thermal power increments and evaluate steam dryer performance based on this data.

   b. NMPNS shall hold the facility at 105 percent and 110 percent of 3467 MWt to collect data from the MSL strain gauges required by Condition 1.a., conduct plant inspections and walkdowns, and evaluate steam dryer performance based on these data; shall provide the evaluation to the NRC staff by facsimile or electronic transmission to the NRC project manager upon completion of the evaluation; and shall not increase power above each hold point until 96 hours after the NRC project manager confirms receipt of the transmission.

   c. During power ascension at each 2.5 percent power level above CLTP, the licensee shall perform stress analysis for the top 100 stress locations of the steam dryer using the applicable ACM 4.1 load definition and determine the minimum alternating stress ratio. The licensee shall confirm that this ratio is equal to or greater than the ratio based on the velocity-square relationship; otherwise, the licensee shall return the facility to a lower power level where the minimum alternating stress ratio satisfies the velocity-square relationship, and shall not further increase the power without approval from the NRC. A summary of the results shall be provided for NRC review at each 5 percent data review plateau. After completion of the full EPU test plateau (approximately 120 percent OLTP or 115 percent CLTP), the licensee shall provide the NRC a full startup test report and final stress analysis report within 90 days.

d. If any frequency peak from the MSL strain gauge data exceeds the Level 1 limit curves, NMPNS shall return the facility to a power level at which the limit curve is not exceeded. NMPNS shall resolve the discrepancy, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation by facsimile or electronic transmission to the NRC project manager prior to further increases in reactor power, except when stress analysis is re-performed and new limit curves are developed. In that case, NMPNS shall not further increase power above each hold point until 96 hours after the NRC project manager confirms receipt of the transmission.

e. In addition to evaluating the MSL strain gauge data, NMPNS shall monitor reactor pressure vessel water level instrumentation, and MSL piping accelerometers on an hourly basis during power ascension above 3467 MWt. If resonance frequencies are identified as increasing above nominal levels in proportion to strain gauge instrumentation data, NMPNS shall stop power ascension, evaluate and document the continued structural integrity of the steam dryer, and provide that documentation to NRC staff by facsimile or electronic transmission to the NRC project manager prior to further increases in reactor power.

2. NMPNS shall implement the following actions for the power ascension from CLTP (3467 MWt) to 120 percent OLTP (3988 MWt) condition.

   a. In the event that acoustic signals (in MSL strain gauge signals) are identified that challenge the limit curves during power ascension above 3467 MWt, NMPNS shall evaluate dryer loads, and stresses, including the effect of ±10 percent frequency shift, and re-establish the limit curves, and shall perform a frequency-specific assessment of ACM uncertainty at the acoustic signal frequency including application of the ACM 4.0 values for percent bias error and for percent uncertainty to all the SRV acoustic resonances. In the event that stress analyses are re-performed based on new strain gauge data to address paragraph 1 above, the revised load definition, stress analysis, and limit curves shall include:

      i. Application of the ACM 4.0 values for percent bias error and for percent uncertainty to all the SRV acoustic resonances.

      ii. Use of bump-up factors associated with all the SRV acoustic resonances and determined from the scale model test results.

      iii. Evaluation of the effect of ±10 percent frequency shifts in increments of 2.5 percent.

   b. NMPNS shall incorporate in NMP2 steam dryer the design modifications identified in Section 2.2.6.1.2 of this SE before increasing the power above CLTP.

   c. After reaching EPU conditions, NMPNS shall obtain measurements from the MSL strain gauges and establish the steam dryer flow-induced vibration load fatigue margin for the facility, update the dryer stress report, and re-establish the limit curves with the updated ACM load definition, which will be provided to the NRC staff.

d. NMPNS shall revise plant procedures to reflect long-term monitoring of plant parameters potentially indicative of steam dryer failure; to reflect consistency of the facility's steam dryer inspection program with BWRVIP-139; and to identify the NRC project manager for the facility as the point of contact for providing power ascension testing information during power ascension.

e. NMPNS shall submit the final EPU steam dryer load definition for the facility to the NRC upon completion of the power ascension test program.

f. NMPNS shall submit the flow-induced vibration related portions of the EPU startup test procedure to the NRC, including methodology for updating the limit curve, prior to initial power ascension above 3467 MWt.

3. NMPNS shall prepare the EPU startup test procedure to include:

a. The stress limit curves to be applied for evaluating steam dryer performance;

b. Specific hold points and their durations during EPU power ascension;

c. Activities to be accomplished during the hold points;

d. Plant parameters to be monitored;

e. Inspections and walkdowns to be conducted for steam, feedwater, and condensate systems and components during the hold points;

f. Methods to be used to trend plant parameters;

g. Acceptance criteria for monitoring and trending plant parameters, and conducting the walkdowns and inspections;

h. Actions to be taken if acceptance criteria are not satisfied; and

i. Verification of the completion of commitments and planned actions specified in its application and all supplements to the application in support of the EPU license amendment request pertaining to the steam dryer prior to power increase above 3467 MWt.

NMPNS shall provide the related EPU startup test procedure sections to the NRC by facsimile or electronic transmission to the NRC project manager prior to increasing power above 3467 MWt.

4. The following key attributes of the program for verifying the continued structural integrity of the steam dryer shall not be made less restrictive without prior NRC approval:

a. During initial power ascension testing above 3467 MWt, each test plateau increment shall be approximately 5 percent of 3467 MWt.

b. Level 1 performance criteria; and

c. The methodology for establishing the limit curves used for the Level 1 and Level 2 performance

5. The results of the power ascension testing to verify the continued structural integrity of the steam dryer and the final steam dryer load definition shall be submitted to the NRC staff in a report within 60 days following the completion of all 120 percent OLTP (EPU) power ascension testing.

6. During the first two scheduled refueling outages after reaching 120 percent OLTP conditions, a visual inspection shall be conducted of all accessible, susceptible locations of the steam dryer in accordance with BWRVIP-139 inspection guidelines. In addition, a visual inspection of all accessible welds that were analyzed using embedded models shall be conducted. In addition, a visual inspection of the existing indications in the upper support ring, the drain channel to skirt weld, the tie bar-to-hood weld heat affected zone, and vertical support plates shall be conducted.

7. The results of the visual inspections of the steam dryer shall be reported to the NRC staff within 90 days following startup from the respective refueling outage.

8. At the end of the second refueling outage, following the implementation of the EPU, the licensee shall submit a long-term steam dryer inspection plan based on industry operating experience along with the baseline inspection results for NRC review and approval.

This license conditions in Section 3.4.1 above shall expire (1) upon satisfaction of the requirements in paragraphs 6 and 7, provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw(s) or unacceptable flaw growth that is due to fatigue, and (2) upon satisfaction of the requirements specified in paragraph 8.

3.4.2 Fatigue Monitoring Program

If stress based fatigue monitoring is used, it shall include all six stress terms in accordance with NB-3200. The condition for this requirement will be carried over and be applicable for operation under EPU conditions and in the plant life extension to 60 years.

4.0 REGULATORY COMMITMENTS

The licensee has made the following regulatory commitments, which have been or will be completed before or concurrent with the EPU amendment implementation or as noted in the individual commitments as "due date":

(1) (NMPNS letter dated May 7, 2010) Submit the responses to requests NMP2-EMCB-SD-RAI - 6, 7, 8, 9, 11, 12, 20, 21 and 24 by June 30, 2010. (Completed by letter dated June 30, 2010).

(2) (NMPNS letter dated May 7, 2010) Submit a revised relief request for elimination of the circumferential reactor vessel weld inspection a full year before the currently approved fluence limit is reached.

(3) (NMPNS letter dated June 30, 2010) The existing steam dryer flaws will be re-examined during the refueling outage implementing EPU and the first refueling outage after implementation of EPU.

(4) (NMPNS letter dated June 30, 2010) The non-proprietary version of CDI Report No. 10- 11 will be submitted by July 9, 2010. (Completed by letter dated July 9, 2010).

(5) (NMPNS letter dated June 30, 2010) By July 30, 2010, NMP2 will submit its evaluation and conclusions regarding the recently identified indications in the steam dryer hood support attachment. (Completed by letter dated July 30, 2010).

(6) (NMPNS letter dated November 5, 2010) A revised CDI Report No. 10-10P will be provided that includes the details of the response to NMP2-EMCB-SD-RAI-8 S01 by December 10, 2010. (Completed by letter dated December 10, 2010).

(7) (NMPNS letter dated November 5, 2010) A revision to the responses to [RAIs NMP2-EMCB- SD-RAI-6 S01 (b), -23 S01, and -24 S01] will be issued to address the final response to NMP2-EMCB-SD-RAI-8 S01(a) by December 10, 2010. (Completed by letter dated December 10, 2010).

(8) (NMPNS letter dated November 5, 2010) A revised benchmark report (CDI Report No. 10- 09P) and NMP2 specific loads report (CDI Report No. 10-10P) will be provided based on [the approach described in the response to RAI NMP2-EMCB-SD-RAI-8 S01(a)] by December 10, 2010. (Completed by letter dated December 10, 2010).

(9) (NMPNS letter dated November 5, 2010) NMPNS will revise the ACM Rev. 4.1 model to provide bias and uncertainty values over frequency ranges consistent with those used for ACM Rev. 4.0 by December 10, 2010. (Completed by letter dated December 10, 2010).

(10) (NMPNS letter dated December 10, 2010) Within two months of final resolution of NRC RAIs regarding the steam dryer analysis methodology, NMPNS will submit a revision to CDI Report No.10-12, Design and Stress Evaluation of Nine Mile Point Unit 2 Steam Dryer Modifications for EPU Operation. (Completed by letter dated June 13, 2011).

(11) (NMPNS letter dated June 13, 2011) NMPNS will conduct in-situ Boron-10 Areal Density Gauge for Evaluating Racks (BADGER) testing on the Phase 1 BORAL® Racks installed at NMP2 in 2001 on a 10-year frequency, beginning in 2012. The BADGER testing program will be the surveillance program for the Phase 1 BORAL® Racks installed at NMP2 in 2001.

(12) (NMPNS letter dated August 5, 2011) Prior to power ascension (i.e., prior to commencing power operations above CLTP), NMPNS plans to update the sample limit curves using the power ascension strain gauge data from the Current Licensed Thermal Power

(CLTP). This approach is a lesson learned from the Hope Creek EPU power ascension where plant noise profiles and refurbished strain gauges impacted the limit curves, requiring the regeneration of the curves. The regenerated limit curves will be submitted to the NRC prior to commencing power operations above CLTP.

(13) (NMPNS letter dated August 5, 2011) During the ascent to EPU conditions from 100 percent CLTP, data from the strain gauges on the main steam lines will be collected at 1 percent intervals and evaluated every 2.5 percent increase. Hold points will be established every 5 percent above CLTP for Plant Operations Review Committee (PORC) and NRC reviews. NMPNS will not increase power above each hold point until 96 hours after submittal of the applicable evaluation to the NRC.

(14) (NMPNS letter dated August 5, 2011) The planned action to be taken at Level 1 and Level 2 is as follows:

If Level 2 criteria are reached, reactor power ascension is to be suspended until an engineering evaluation concludes that further power ascension is justified. Should Level 1 be reached or exceeded, reactor power is returned to a previously acceptable power level that satisfies Level 2 criteria while an engineering evaluation is undertaken.

If Level 1 or 2 criteria are reached, NMPNS would perform a real time stress analysis based on the strain gauge data, regenerate the limit curves, and submit them to the NRC. Similar to the hold points, power would not be increased until 96 hours after submittal to the NRC.

The NRC staff finds that reasonable controls for the implementation and for subsequent evaluation of proposed changes pertaining to the above regulatory commitments are best provided by the licensee's administrative processes, including its commitment management program. The above regulatory commitments do not warrant the creation of regulatory requirements (items requiring prior NRC approval of subsequent changes).

5.0 RECOMMENDED AREAS FOR INSPECTION

As described above, the NRC staff conducted an extensive review of the licensee's plans and analyses related to the proposed EPU and concluded that they are acceptable. The NRC staff's review identified the following areas for consideration by the NRC inspection staff during the licensee's implementation of the proposed EPU:

- Spent Fuel Criticality Analysis
- LTS and ATWS
- Power ascension testing activities (License Condition 3.4.1)

These areas are recommended based on past experience with EPUs, the extent and unique nature of modifications necessary to implement the proposed EPU, and new conditions of operation necessary for the proposed EPU. They do not constitute inspection requirements but are intended to give inspectors insight into important bases for approving the EPU.

6.0 STATE CONSULTATION

In accordance with the Commission's regulations, the NRC notified the New York State official of the proposed issuance of the amendment. The State official had no comments.

7.0 ENVIRONMENTAL CONSIDERATION

Pursuant to 10 CFR 51.21, "Criteria for and Identification of Licensing and Regulatory Actions Requiring Environmental Assessments," 10 CFR 51.32, "Finding of No Significant Impact," 10 CFR 51.33, "Draft Finding of No Significant Impact; Distribution," and 10 CFR 51.35, "Requirement to Publish Finding of No Significant Impact; Limitation on Commission Action," the NRC prepared a draft environmental assessment and finding of no significant impact, published in the *Federal Register* on April 8, 2010 (75 FR 17970). The draft environmental assessment provided a 30-day opportunity for public comment. The NRC staff received no public comments. The final environmental assessment was published in the *Federal Register* on November 29, 2011 (76 FR 73721). 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 CONCLUSION

The Commission has concluded, based on the considerations discussed above, 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) such activities 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.

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Attachment 7, "EPU Test Plan," (ML091610105 (non-proprietary));

Attachment 8, "Grid Stability Evaluation," (ML091610105 (non-proprietary));

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Attachment:
List of Acronyms

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Date: December 22, 2011

ATTACHMENT - LIST OF ACRONYMS

ACRONYM	DEFINITION
AAC	Alternate AC Sources
ABA	Amplitude Based Algorithm
AC	Alternating Current
ADHR	Alternate Decay Heat Removal
ADS	Automatic Depressurization System
AFIL	Acoustic and Flow Induced Loads
AHC	Access Hole Cover
AL	Analytical Limit
ALARA	As Low As reasonable Achievable
ALT	As Left Tolerance
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOO	Anticipated Operational Occurrence (moderate frequency transient event)
AOP	Alternate Operating Procedure
AOR	Analysis of Record
AOV	Air-Operated Valve
AP	Annulus Pressurization
APRM	Average Power Range Monitor
ARI	Alternate Rod Insertion
ARS	Acceleration Response Spectra
ARTS	APRM/RBM/Technical Specifications
ASME	American Society of Mechanical Engineers
ASDC	Alternate Shutdown Cooling
AST	Alternate Source Term
ATU	Analog Trip Unit
ATWS	Anticipated Transient Without Scram
AV	Allowable Value
AWLZ	Above Water Level Zero
BHP	Brake Horsepower
BIIT	Boron Injection Initiation Temperature
BOC	Beginning of Cycle
BOP	Balance-of-Plant
B&PV	Boiler and Pressure Vessel
BPWS	Banked Position Withdrawal Sequence
BSP	Backup Stability Protection
BSW	Biological Shield Wall
BTU	British Thermal Unit
BUF	Bump-Up Factor
BWR	Boiling Water Reactor
BWROG	BWR Owners Group
BWRVIP	BWR Vessel and Internals Project
CAD	Containment Atmospheric Dilution
CBP	Condensate Booster Pump
CDF	Core Damage Frequency
CFD	Condensate Filter Demineralizer

ACRONYM	DEFINITION
CFR	Code of Federal Regulations
CFS	Condensate and Feedwater System
CGCS	Combustible Gas Control System
CGG	Constellation Generation Group LLC
CLTP	Current Licensed Thermal Power
CLTR	Constant Pressure Power Uprate Licensing TR
CMS	Containment Atmospheric Monitoring System
CMTR	Certified Material Test Report
CO	Condensation Oscillation
COLR	Core Operating Limits Report
CPPU	Constant Pressure Power Uprate
CPR	Critical Power Ratio
CRD	Control Rod Drive
CRDA	Control Rod Drop Accident
CRAVS	Control Room Area Ventilation System
CREF	Control Room Emergency Filtration System
CREVS	Control Room Emergency Ventilation System
CRGT	Control Rod Guide Tube
CRHZ	Control Room Habitability Zone
CS	Core Spray
CSC	Containment Spray Cooling
CSH	High Pressure Core Spray
CSL	Low Pressure Core Spray
CST	Condensate Storage Tank
CT	Current Transformer
CUF	Cumulative Usage Factors
CWS	Circulating Water System
DBA	Design-Basis Accident
DBLOCA	Design Basis Loss-of-Coolant Accident
DC	Direct Current
DFFR	Dynamic Forcing Function Report
DIVOM	Delta CPR over Initial CPR Versus Oscillation Magnitude
DLO	Dual (Recirculation) Loop Operation
DVS	Drywell Ventilation System
DW	Dry Well
EAB	Exclusion Area Boundary
ECCS	Emergency Core Cooling System
EECW	Emergency Equipment Cooling Water
EFDS	Equipment and Floor Drainage System
EFPY	Effective Full Power Years
ELLLA	Extended Load Line Limit Analysis
ELTR1	Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate Licensing TR
ELTR2	Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate Licensing TR
EOC	End of Cycle
EOP	Emergency Operating Procedure

ACRONYM	DEFINITION
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
FCV	Flow Control Valve
FFWTR	Final Feedwater Temperature Reduction
FHA	Fuel Handling Accident
FIV	Flow Induced Vibration
FLIM	Failure Likelihood Index Methodology
FLL	Fuel Lift Loads
FPC	Fuel Pool Cooling
FPCCS	Fuel Pool Cooling and Cleanup System
FPP	Fire Protection Program
FSAR	Final Safety Analysis Report
FV	Fussel-Vesely
FW	Feedwater
FWCF	Feedwater Controller Failure Maximum Demand
FWHOOS	Feedwater Heater Out-of-Service
FWP	Feedwater Pump
FWS	Feedwater System
FWTR	Feedwater Temperature Reduction
GDC	General Design Criteria
GE	General Electric
GEH	GE-Hitachi Nuclear Energy Americas LLC
GL	Generic Letter
GNF	Global Nuclear Fuel LLC
GRA	Growth Rate Based Algoritham
GSF	Generic Shape Function
GSU	Generator Step Up
GWMS	Gaseous Waste Management (Offgas) System
HCR	Human Cognitive Reliability
HCTL	Heat Capacity Temperature Limit
HDP	Header Discharge Pressure
HELB	High Energy Line Break
HEP	Human Error Probability
HEPA	High Efficiency Particulate Air
HFCL	High Flow Control Line
Hga	Inches of Mercury Absolute
HPCS	High Pressure Coolant Spray
HPT	High Pressure Turbine
HRA	Human Reliability Analysis
HVAC	Heating Ventilating and Air Conditioning
HWL	High Water Level

ACRONYM	DEFINITION
HX	Heat Exchanger
IASCC	Irradiation-Assisted Stress Corrosion Cracking
ICA	Interim Corrective Action
ICF	Increased Core Flow
IEB	Inspection & Enforcement Bulletins
ICS	Integrated Computer System
IEEE	Institute of Electrical and Electronics Engineers
IGSCC	Intergranular Stress Corrosion Cracking
ILBA	Instrument Line Break Accident
IORV	Inadvertent Opening of a Relief Valve
IPB	Isolated Phase Bus
IPE	Individual Plant Examination
IPEEE	Individual Plant Examination of External Events
IRM	Intermediate Range Monitor
ISLOCA	Interfacing System Loss-of-Coolant Accident
ISP	Integrated Surveillance Program
ISI	In-Service Inspection
IST	In-Service Testing
JR	Jet Reaction
LAT	Leave Alone Tolerance
LCS	Leakage Control System
LDS	Leak Detection System
LER	Licensee Event Report
LERF	Large Early Release Frequency
LFWH	Loss of Feedwater Heater
LHGR	Linear Heat Generation Rate
LLHS	Light Load Handling System
LOC	Loss of Condenser
LOCA	Loss-of-Coolant Accident
LOCV	Loss of Condenser Vacuum
LOFW	Loss of Feedwater
LOOP	Loss of Offsite Power
LPCI	Low Pressure Coolant Injection
LPCS	Low Pressure Core Spray
LPRM	Local Power Range Monitor
LPSP	Low Power Setpoint
LRNBP	Generator-Load Rejection with no Steam Bypass Failure
LTR	Licensing TR
LWL	Low Water Level
LWMS	Liquid Waste Management System
MAAP	Modular Accident Analysis Program
MAPLHGR	Maximum Average Planar Linear Heat Generation Rate
MBTU	Millions of BTUs
MC	Main Condenser
MCPR	Minimum Critical Power Ratio
MCR	Main Control Room
MELB	Moderate Energy Line Break

ACRONYM	DEFINITION
MELLLA	Maximum Extended Load Line Limit Analysis
MeV	Million Electron Volts
MFLCPR	Maximum Fraction of Limiting Critical Power Ratio (ratio MCPR to limit)
MFLPD	Maximum Fraction of Limiting Power Density (ratio MLHGR to limit)
Mlb	Millions of Pounds
MLOCA	Medium Loss-of-Coolant Accident
MOC	Middle of Cycle
MOV	Motor Operated Valve
MS	Main Steam
MSIV	Main Steam Isolation Valve
MSIVC	Main Steam Isolation Valve Closure
MSIVF	Main Steam Isolation Valve Closure with Scram on High Flux
MSL	Main Steam Line
MSLB	Main Steam Line Break
MSLBA	Main Steam Line Break Accident
MSRV	Main Steam Relief Valve
MSS	Main Steam System
MSVV	Main Steam Valve Vault
MVA	Million Volt Amps
Mvar	Megavar
MWe	Megawatts-Electric
MWt	Megawatt-Thermal
NA	Not Applicable
NCL	Natural Circulation Line
NDE	Non-Destructive Testing
NMP2	Nine Mile Point Nuclear Station Unit 2
NMPC	Niagra Mohawk Power Corporation
NMPNS	Nine Mile Point Nuclear Station, LLC
NPSH	Net Positive Suction Head
NPSHR	Net Positive Suction Head Required
NRC	Nuclear Regulatory Commission
NSSS	Nuclear Steam Supply System
NTSP	Nominal Trip Set Point
NUREG	Nuclear Regulatory Commission Technical Report Designation
OFS	Orificed Fuel Support
OLMCPR	Operating Limit Minimum Critical Power Ratio
OLTP	Original Licensed Thermal Power
OOS	Out-of-Service
OPRM	Oscillation Power Range Monitor
ΔP	Differential Pressure - psi
P25	25 percent of EPU Rated Thermal Power
PBDA	Period Based Detection Algorithm
PCPL	Primary Containment Pressure Limit
PCS	Pressure Control System
PCT	Peak Clad Temperature
PF	Power Factor

ACRONYM	DEFINITION
PLOF	Partial Loss of Feedwater Initiating Event
PRA	Probabilistic Risk Assessment
PRFD	Pressure Regulator Failure Downscale
PRFO	Pressure Regulator Failure Open
PSA	Probabilistic Safety Analysis
PSF	Performance-Shaping Factor
psi	Pounds per Square Inch
psia	Pounds per Square Inch - Absolute
psid	Pounds per Square Inch - Differential
psig	Pounds per Square Inch - Gauge
PSP	Pressure Suppression Pressure
PSPL	Primary Suppression Pressure Limit
P-T	Pressure-Temperature
PUSAR	Power Uprate Safety Analysis Report
RAVS	Radwaste Area Ventilation System
RAW	Risk Achievement Worth
RBCCW	Reactor Building Closed Cooling Water
RBCLC	Reactor Building Closed Loop Cooling
RBM	Rod Block Monitor
RCIC	Reactor Core Isolation Cooling
RCPB	Reactor Coolant Pressure Boundary
RCS	Reactor Coolant System
RCW	Raw Cooling Water
RG	Regulatory Guide
RHS	Residual Heat Removal System
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RIPD	Reactor Internal Pressure Difference
RLA	Reload Licensing Analysis
RMS	Root Mean Square
RMS	Radiation Monitoring System
RPT	Recirculation Pump Trip
RPV	Reactor Pressure Vessel
RRRB	Reactor Recirculation Runback
RRS	Reactor Recirculation System
RSLB	Recirculation System Line Break
RSP	Remote Shutdown Panel
RTNDT	Reference Temperature of Nil-Ductility Transition
RTP	Rated Thermal Power
RWE	Rod Withdrawal Error
RWM	Rod Worth Minimizer
Salt	EPU Alternating Stress Intensity
Sm	Code Allowable Stress Limit
SAFDL	Specified Acceptable Fuel Design Limits
SAR	Safety Analysis Report
SBO	Station Blackout
SCM	Steam Condensing Mode

ACRONYM	DEFINITION
SDC	Shutdown Cooling
SER	SE Report
SFC	Spent Fuel Pool Cooling
SFP	Spent Fuel Pool
SFPC	Spent Fuel Pool Cooling
SFPAVS	Spent Fuel Pool Area Ventilation System
SGTS	Standby Gas Treatment System
SHB	Shroud Head Bolts
SIL	Service Information Letter
SJAE	Steam Jet Air Ejectors
SLCS	Standby Liquid Control System
SLMCPR	Safety Limit Minimum Critical Power Ratio
SLO	Single Loop Operation
SLOCA	Small Loss-of-Coolant Accident
SORV	Stuck Open SRV
SOV	Solenoid-Operated Valve
SP	Suppression Pool
SPC	Suppression Pool Cooling
SPDS	Safety Parameter Display System
SPDES	State Pollutant Discharge Elimination System
SRLR	Supplemental Reload Licensing Report
SRM	Source Range Monitor
SRP	Standard Review Plan
SRV	Safety Relief Valve(s)
SRVDL	Safety Relief Valve Discharge Line
SSC	Systems Structures Components
SSE	Safe Shutdown Earthquake
SSP	Supplemental Surveillance Capsule Program
SSV	Spring Safety Valve
STP	Simulated Thermal Power
SWMS	Solid Waste Management Systems
SWS	Station Service Water System
TAF	Top of Active Fuel
TAVS	Turbine Area Ventilation System
TBCCW	Turbine Building Closed Loop Cooling Water
TBS	Turbine Bypass System
TCV	Turbine Control Valve
TEDE	Total Effective Dose Equivalent
TFSP	Turbine First-Stage Pressure
T-G	Turbine-Generator
TIP	Traversing Incore Probe
TLO	Two Loop Operation
TSV	Turbine Stop Valve
TSVC	Turbine Stop Valve Closure
TT	Turbine Trip
TTNBP	Turbine Trip with no Steam Bypass Failure
Tw	Time Available

ACRONYM	DEFINITION
UHS	Ultimate Heat Sink
UPS	Uninterruptible Power Supply
USAR	Updated Safety Analysis Report
USE	Upper Shelf Energy
VB	Vacuum Breaker
WCS	Reactor Water Cleanup System
WW	Wet Well

Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/ra/

Richard V. Guzman, Senior Project Manager
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-410

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1. Amendment No. 140 to License No. NPF-69
2. Non-Proprietary Safety Evaluation (ML113560333)
3. Proprietary Safety Evaluation (ML112930470)

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