NMC
Committed to Nuclear Excellence

Monticello Nuclear Generating Plant
Operated by Nuclear Management Company, LLC

WITHHOLD ENCLOSURES 5 and 11 FROM PUBLIC DISCLOSURE UNDER 10 CFR 2.390

March 31, 2008

L-MT-08-018
10 CFR 50.90

U. S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington, DC 20555-0001

Monticello Nuclear Generating Plant
Docket 50-263
Renewed Facility Operating License
License No. DPR-22

License Amendment Request: Extended Power Uprate

References
1) June 19, 2007, "Summary of the June 5, 2007, Meeting With the Licensee to Discuss Pre-Application Issues Related to a Future Extended Power Uprate Amendment Application (TAC NO. MD5531)," ML071580627

2) October 19, 2007, "Summary of the October 3, 2007, Meeting With the Licensee to Discuss Pre-Application Issues Related to a Future Extended Power Uprate Amendment Application (TAC NO. MD5531)," ML072780599

3) February 21, 2008, "Summary of the February 13, 2008, Meeting With the Licensee to Discuss Pre-Application Issues Related to a Future Extended Power Uprate Amendment Application (TAC NO. MD5531)," ML080450168

Pursuant to 10 CFR 50.90, Nuclear Management Company, LLC (NMC), hereby requests approval of an amendment to the Monticello Nuclear Generating Plant (MNGP) Renewed Operating License (OL) and Technical Specifications (TS) as described in Enclosure 1. The proposed change would increase the maximum power level authorized by OL Section 2.C (1) from 1,775 megawatts thermal (MWt) to 1,870 MWt, an approximate five percent increase in the current licensed thermal power (CLTP). This proposed request for Extended Power Uprate (EPU) represents an increase of approximately 12 percent above the Original Licensed Thermal Power (OLTP). This request also includes the supporting TS changes necessary to implement the increased power level.

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This planned application was the topic of public meetings between the NRC and NMC on June 5, 2007 (Reference 1), October 3, 2007 (Reference 2), and February 13, 2008 (Reference 3).

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

NMC plans to implement a 2,004 MWt EPU in two phases. NMC plans to implement the first phase of the EPU to 1,870 MWt during or following the spring 2009 refueling outage. NMC plans on implementing the second phase of the EPU to 2,004 MWt at a later date. Based on this two phased EPU implementation plan, two MNGP power increase interconnection requests with the Midwest Independent System Operator, Inc (MISO) were submitted. The first request was for the expected increase in generation following modifications planned for the 2009 MNGP refueling outage. The second request was for the remaining increase in generation following modifications planned for the 2011 refueling outage.

During a telephone conference between NMC and NRC staff on March 27, 2008, it was agreed that the NRC review would be performed at a power level of 2,004 MWt which supports the current request for operation at 1,870 MWt. NMC plans to submit a license amendment request for the implementation of phase two of the EPU (to 2,004 MWt) when the 2011 interconnection study request becomes available.

NMC has evaluated the proposed changes in accordance with the requirements of 10 CFR 50.91 against the standards of 10 CFR 50.92 and has determined this request involves no significant hazards. Enclosures to this letter contain information supporting the proposed change. These enclosures are described below.

Enclosure 1 contains NMC's evaluation of this proposed change. Included are a description of the proposed change, technical analysis of the change, regulatory safety analysis of the change (No Significant Hazards Consideration and the applicable regulatory requirements/criteria), and environmental consideration.

Enclosure 2 provides a mark-up of the Technical Specifications and the Operating License (OL) indicating the proposed changes. Additionally, NMC is transferring the OL to Northern States Power - Minnesota. The enclosed markup of the OL pages does not reflect this pending change and the OL pages will need to be reconciled prior to issuance of the EPU amendment.

Enclosure 3 provides a copy of the associated draft mark-up TS Bases pages for information.

Enclosure 4 contains the MNGP Extended Power Uprate Environmental Assessment supporting a conclusion of no significant impact.

Enclosure 5 contains the power uprate safety analysis report[1] (PUSAR) formatted in accordance with RS-001, "Review Standard for Extended Power Uprates." The PUSAR is an integrated summary of the results of the safety analysis and evaluations performed specifically for the MNGP EPU and follows the guidelines contained in General Electric (GE) Licensing Topical Reports (LTR) NEDC-33004P-A, "Constant Pressure Power Uprate" (CLTR). NRC has approved use of this LTR for reference as a basis for a power uprate license amendment request with the exception of the CLTR's proposed elimination of large transient testing.

Enclosure 5 contains information which is proprietary to GE Hitachi (GEH). GEH requests that this proprietary information be withheld from public disclosure in accordance with 10 CFR 2.390(a)4 and 9.17(a)4. An affidavit supporting this request is provided in Enclosure 6. A non-proprietary version of the PUSAR is provided as Enclosure 7.

Enclosure 8 includes a list of modifications planned for EPU implementation. The modifications listed in Enclosure 8 are planned actions which do not constitute regulatory commitments by NMC. Modifications listed in Enclosure 8 are being implemented in accordance with the requirements of 10 CFR 50.59. The Enclosure 8 tables also include modifications that are not required for EPU but have been approved as part of the ongoing life cycle management (LCM) program for MNGP. These LCM modifications are planned to be coordinated with the EPU project and are planned to incorporate EPU conditions to maintain or improve performance margin of the respective systems.

Enclosure 9 provides the MNGP Extended Power Uprate Startup Test Plan. This enclosure specifies the EPU testing planned and provides a comparison of initial startup testing and EPU testing. Enclosure 9 includes justification for not performing the main steam isolation valve (MSIV) closure and the load rejection transient tests. Enclosure 9 supplements PUSAR Section 2.12.

Enclosure 10 provides a discussion of the analyses and testing program planned to provide assurance that unacceptable flow induced vibration issues are not experienced at MNGP due to EPU implementation.

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[1] The actual title of this document is Safety Analysis Report for Monticello Constant Pressure Power Uprate

Enclosure 11 provides the Steam Dryer Dynamic Stress Evaluation. This enclosure summarizes the analyses performed to demonstrate the structural adequacy of the MNGP steam dryer at EPU conditions. Enclosure 11 contains information which is proprietary to Continuum Dynamics Incorporated (CDI). CDI requests that this proprietary information be withheld from public disclosure in accordance with 10 CFR 2.390(a)4 and 9.17(a)4. An affidavit supporting this request is provided in Enclosure 12. Enclosure 13 contains the non-proprietary version of the Steam Dryer Dynamic Stress Evaluation.

Enclosure 14 is a summary of a grid stability evaluation performed at the expected full EPU electrical output (2,004 MWt) that demonstrates that the EPU will not have a significant effect on the reliability or operating characteristics of MNGP or on the offsite system. The evaluation was performed by an independent engineering firm. By June 30, 2008, NMC will submit a summary of the grid stability evaluation provided by the Midwest Independent Transmission System Operator, Inc. (MISO) for the expected electrical output for the first phase of the EPU.

Enclosure 15 is the Identification of Risk Implications Due to Extended Power Uprate at Monticello and provides an assessment of the power uprate impacts on risk relative to the current probabilistic risk assessment (PRA). This Enclosure supplements PUSAR Section 2.13.

Commitment Summary

This letter makes the following new commitment:

1. The NMC will submit a summary of the MISO grid stability study completed for the electrical output for the first implementation phase of the EPU. This summary will be submitted by June 30, 2008.

Two existing commitments initially issued in conjunction with the 24-month fuel cycle license amendment for the MNGP are applicable and will be extended to include this license amendment request. NMC made these commitments to address industry / NRC instrumentation issues in the interim until TSTF-493, "Clarify Application of Setpoint Methodology for LSSS Functions," is approved and issued by the NRC. These two commitments are restated below:

- Continue resetting Limiting Safety System Settings (LSSS) setpoints within the specified tolerances (as-left criteria) until the Technical Specification Task Force's TS change pertinent to instrument setpoints [i.e., TSTF-493] has been approved by the NRC and assessed for applicability to Monticello.

- Assess applicability of the Technical Specification Task Force's TS change pertinent to instrument setpoints [i.e., TSTF-493], when approved by the NRC, to determine whether changes to Monticello's licensing basis are necessary.

As stated earlier in this letter, a two phased implementation of the EPU is planned. NMC plans to implement the first phase of the EPU during or following the spring 2009 refueling outage. NMC plans to implement the second phase of the EPU at a later date. Therefore, NMC requests an approval date of April 1, 2009 to support NMC's implementation schedule of the first phase of the EPU. Implementation of the EPU amendment request is planned to be completed within 120 days of NRC approval. In accordance with 10 CFR 50.91(b), a copy of this application, with non-proprietary Enclosures is being provided to the designated Minnesota Official.

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

Executed on March 31, 2008.

FOR

Timothy J. O'Connor
Site Vice President, Monticello Nuclear Generating Plant
Nuclear Management Company, LLC

cc: Administrator, Region III, USNRC
Project Manager, Monticello, USNRC
Resident Inspector, Monticello, USNRC
Minnesota Department of Commerce w/o enclosures 5 and 11

Enclosures (15)

Enclosure 1 to L-MT-08-018

NMC Evaluation of Proposed Changes to Operating License and Technical Specifications for Extended Power Uprate

ENCLOSURE 1

DESCRIPTION OF CHANGE
LICENSE AMENDMENT REQUEST
EXTENDED POWER UPRATE

1.0 SUMMARY DESCRIPTION

This evaluation supports a request to amend Renewed Operating License (OL) DPR-22 for Monticello Nuclear Generating Plant (MNGP). The proposed amendment includes supporting changes to the Operating License and Technical Specifications (TSs) necessary to implement the increased power level.

The proposed changes would change the TS definition of the term "Rated Thermal Power (RTP)." The proposed changes also revise the OL to increase the MNGP authorized steady state reactor core power level to 1,870 megawatts thermal (MWt), which is approximately 12 percent above the original rated thermal power (RTP) of 1,670 MWt, and approximately five percent above the current RTP of 1,775 MWt.

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

Enclosure 5 contains the power uprate safety analysis report (PUSAR) formatted in accordance with RS-001, "Review Standard for Extended Power Uprates." The PUSAR follows the guidelines contained in General Electric (GE) Licensing Topical Reports (LTR) NEDC-33004P-A, "Constant Pressure Power Uprate" (CLTR) (Reference 1). The PUSAR provides the technical bases for this request and contains an integrated summary of the results of the underlying safety analyses and evaluations performed specifically for the MNGP extended power uprate (EPU). The PUSAR analyses were completed to support an EPU to 2,004 MWt. The 2,004 MWt power used in analyses bounds the requested change in licensed thermal power to 1,870 MWt.

As part of the MNGP EPU request, NMC is also proposing changes to the licensing basis for methodology used for containment analysis, credit for use of containment overpressure for net positive suction head (NPSH) for low pressure Emergency Core Cooling System (ECCS) pumps, and reactor internal pressure differentials for the steam dryer.

A two-phased implementation of the EPU is planned. NMC plans to implement the first phase of the EPU during or following the spring 2009 refueling outage. The proposed changes of this license amendment request support operation at the requested maximum authorized thermal power level of 1,870 MWt. This thermal power level conservatively correlates to the electrical power cited in the

interconnection request for the first implementation phase of the EPU (620 MWe net generation to the grid). NMC plans to implement the second phase of the EPU at a later date. Therefore, NMC requests an approval date of April 1, 2009 to support NMC's implementation schedule of the first phase of the EPU. Implementation of the EPU amendment request (proposed changes) is planned to be completed within 120 days of NRC approval.

The CLTR Section 6.1, states the licensee will perform a grid stability evaluation and the results of that evaluation will be summarized in the plant-specific submittal. The MNGP grid stability evaluation, to be performed by the independent system operator, is coordinated through Xcel Energy. The Midwest Independent System Operator, Incorporated (MISO) is the regional transmission organization that controls the connected transmission facilities.

Based on the two-phase EPU implementation described above, Xcel Energy submitted two MNGP power increase interconnection requests with the Midwest Independent System Operator, Inc (MISO). The first request was for the expected increase in generation following modifications planned for the 2009 MNGP refueling outage. The second request was for the remaining increase in generation following modifications planned for the 2011 refueling outage. Xcel Energy prepared the interconnection requests allowing reasonable time frames for MISO study to support the generation increases in 2009 and in 2011. The timing of the interconnection request submittals was based on Xcel's experience. Other interconnection study requests currently have priority over the Monticello 2011 request. Due to Federal Energy Regulatory Commission (FERC) regulations governing the MISO, the Monticello requests can not be given priority over the other requests.

Currently, the 2009 interconnection study request is scheduled to be completed by the MISO in June 2008. The interconnection study request for the remaining portion of the increase in electrical generation is forecast to start in 2018. MISO expects to complete the evaluation within 18 months from its initiation. NMC is continuing to work with the MISO on the completion schedule for the 2011 interconnection study. NMC is told that MISO is pursuing the viability of changing the regulations that currently govern the interconnection queue by submitting a requested rule change application to FERC.

To support NRC review pending completion of the 2009 interconnection study request (the formal MISO study), NMC is providing a summary of the grid stability evaluation performed at the EPU rated thermal power level of 2,004 MWt. This evaluation was completed by an independent consulting firm as Enclosure 14. This study was performed in a manner consistent with the MISO study process and is, therefore, expected to give an accurate insight into the probable results of the upcoming MISO studies. Additionally, NMC commits to submit a summary of the first MISO study results supporting the 2009 EPU implementation by June 30, 2008. NMC plans to submit a license amendment request for the implementation of phase two of the EPU (to 2,004 MWt) when the 2011 interconnection study request becomes available.

Although NMC has proposed changes to increase the licensed thermal power to 1,870 MWt, the safety analyses, including the emergency core cooling system and containment performance, have been evaluated at an RTP of 2,004 MWt and the revised TS are based on an RTP of 2,004 MWt. Therefore, NMC requests that a full scope review of the EPU (to 2,004 MWt) be performed by the NRC with the exception of grid stability. NMC has committed to provide a summary of the grid stability evaluation for the first phase of the EPU (1,870 MWt) by June 30, 2008.

2.0 PROPOSED CHANGE

The marked-up pages for the proposed changes to the OL and the Technical Specifications are included in Enclosure 2 of this submittal. One page of Enclosure 2 (TS page 3.3.1.1-6) has been retyped to include the Power Range Neutron Monitoring System (PRNMS) proposed changes (Reference 9). Additionally, NMC is transferring the OL to Northern States Power - Minnesota. The markup of the OL pages does not reflect this change. The OL pages will need to be reconciled prior to issuance of the EPU amendment.

This EPU proposal would change the following:

Extended Power Uprate

NMC is requesting an increase in the licensed thermal power for MNGP from 1,775 MWt to 1,870 MWt. This represents an increase of approximately five percent from the current RTP.

Proposed changes to the OL and TSs are listed in Table 1 with a brief description of the basis for the change.

For clarity, selected TSs that include values expressed in percent RTP not affected or changed by this request are discussed in Table 2. Any value expressed in percent RTP that is not revised for EPU represents an actual change in absolute power level (i.e., MWt). The table provides a listing of these values and the bases for not changing them.

NMC proposes to make the supporting changes to the TS Bases in accordance with TS 5.5.9, "Technical Specifications (TS) Bases Control Program." Associated TS Bases changes are provided in Enclosure 3, for information only.

The CLTR (Reference 1) Section 6.1 states that the licensee will perform a grid stability evaluation and the results of that evaluation will be summarized in the plant-specific submittal. As discussed in Section 1.0 of this enclosure, a grid stability evaluation by the MISO is not complete. NMC contracted an independent consulting firm to conduct a grid stability evaluation assuming the full EPU generation increase. The results of this evaluation are summarized as Enclosure 14. NMC requests that a full scope review of the EPU be performed by the NRC with the exception of grid stability as explained in Section 1.0 of this

Enclosure. As part of the EPU, NMC is also proposing the following changes to the Licensing Basis:

Methodology Used for Containment Analysis

In support of the proposed constant pressure extended power uprate, re-evaluation of the DBA-LOCA (design basis accident - loss of coolant accident) containment analyses was required. Re-evaluation of the associated long-term response analyses were performed by GE with the SHEX code, which is the MNGP current licensing basis methodology except for station blackout (SBO). With respect to the revised analysis, three alternate analytical elements were employed which are not part of the MNGP current licensing basis for containment analysis. These elements are: 1) crediting the presence of passive containment heat sinks for the DBA-LOCA analysis; 2) allowing the residual heat removal (RHR) heat exchanger capability (K-Value, BTU/sec°F) to vary as a function of hot inlet temperature for the long term DBA-LOCA analysis; and (3) assuming mechanistic heat and mass transfer from the suppression pool surface to the wetwell airspace after 30 seconds for the long term DBA-LOCA containment analysis. NRC approval is requested for these three elements since they are changes to the current licensing basis for containment analysis. Approval is also requested for use of the SHEX code for containment analysis performed for station blackout.

Increase in Credit for Containment Overpressure for Low Head ECCS Pumps

The NRC, by its safety evaluation report (SER) dated June 2, 2004 (Reference 8), approved use of containment overpressure for the low head ECCS pumps for DBA-LOCA and Appendix R for MNGP. EPU operation increases the reactor decay heat, which increases the heat addition to the suppression pool following an event. As a result, both the suppression pool water temperature and containment pressure increase. Changes in vapor pressures corresponding to the increases in suppression pool temperatures affect the NPSH margins. NRC approval is requested for a change to the current licensing basis for use of 21.20 psia containment pressure for the low head ECCS pumps to bound all design and licensing basis events.

Reactor Internal Pressure Differentials (RIPDs) for the Steam Dryer

The effects on reactor internal loads as a result of EPU were evaluated. The increase in core power generally results in increased RIPDs for reactor internals due to the higher core exit steam quality. The RIPDs for the steam dryer in the EPU analysis are reduced from those used in the current analyses. NRC approval is requested for this change since it is a change to the current licensing basis for analytical methods used for evaluation of the loads for the reactor internals. The EPU methodology is based on a more realistic correlation for a BWR3 steam dryer instead of air test data for BWR6 steam dryers. The change methodology for determining steam dryer RIPDs is described in Enclosure 5, Section 2.2.3.

Table 1 Monticello Proposed Operating License and Technical Specification Changes		
TS Section	**Description of Change**	**Basis for Change**
License Condition 2.C.1	Revises the value of the Maximum Power Level to the EPU power level of 1,870 MWt.	See this Enclosure, Section 1.0 and Enclosure 5, Section 1.3.1 and Table 1-2.
Operating License Condition 2.C.13 (New)	Add a new License Condition to allow leak rate tests required by Surveillance Requirements SR 3.6.1.1.1, SR 3.6.1.2.1, SR 3.6.1.3.11, SR 3.6.1.3.12, and SR 3.6.1.3.13 to be considered met per SR 3.0.1 upon implementation of the license amendment approving the proposed EPU until the next scheduled performance.	The proposed change precludes having to perform these affected leak rate tests before their next scheduled performance solely for the purpose of documenting compliance. This does not supersede that aspect of Surveillance Requirements (SR) that governs cases where it is believed that, if the SR were performed, it would not be met. Performance of the leak rate tests merely to document compliance would unnecessarily divert resources, interfere with plant operations, potentially incur additional personnel dose, and would not improve plant safety. The results of the integrated leak rate test (ILRT) and local leak rate testing (LLRT) performed in the 2007 refueling outage indicated significant margin to acceptance limits.

Table 1 Monticello Proposed Operating License and Technical Specification Changes		
TS Section	**Description of Change**	**Basis for Change**
1.1, Definitions	Revises the definition of RATED THERMAL POWER (RTP) from 1,775 MWt to 2,004 MWt. Adds the following sentence at the end of the current definition: "This power level is the basis for all safety analyses, including emergency core cooling system (ECCS) and containment performance." The current TS definition for RTP applies to analyses, plant operating parameters (such as setpoints), and the maximum authorized power level. The proposed change to the definition maintains applicability to analyses and plant operating parameters (such as setpoints), however, RTP will no longer refer to the maximum authorized power level.	For power level, see Enclosure 5, Section 1.3.1 and Table 1-2. As the requested maximum authorized power level is less than the analyzed power limit, RTP has been redefined to apply only to the analyses and plant operating parameters (such as setpoints).
3.3.1.1, RPS Instrumentation, Required Action E.1	Revises the value for the Required Action from 45 percent RTP to 40 percent RTP.	Revises the value for the Limit to maintain the value approximately unchanged in thermal power. At current licensed thermal power (CLTP), 45 percent RTP = 798.8 MWt. At EPU 801.6 MWt = 40 percent RTP. Use of 40 percent RTP is slightly less conservative but supported by analysis. See Enclosure 5, Section 2.4.1.3. At CLTP the SR verifies that the functions are not bypassed when power is > 798.8 MWt. At EPU the SR verifies that the functions are not bypassed when power is > 801.6 MWt.

ENCLOSURE 1

Table 1 Monticello Proposed Operating License and Technical Specification Changes		
TS Section	**Description of Change**	**Basis for Change**
3.3.1.1, RPS Instrumentation SR 3.3.1.1.6	Revise the Frequency from 2000 effective full power hours to 1770 effective full power hours.	Revises the value for the Frequency to maintain the value approximately unchanged in fluence between performances. (2000 effective full power hours (EFPH) X 1,775 MWt / 2,004 MWt = 1771.5 EFPH)
3.3.1.1, RPS Instrumentation SR 3.3.1.1.13	Revises the limit specified in the SR from 45 percent RTP to 40 percent RTP.	Revises the value for the Limit to maintain the value approximately unchanged in thermal power. At CLTP, 45 percent RTP = 798.8 MWt. At EPU 801.6 MWt = 40 percent RTP. Use of 40 percent RTP is slightly less conservative but supported by analysis. See Enclosure 5, Section 2.4.1.3. At CLTP the SR verifies that the functions are not bypassed when power is > 798.8 MWt. At EPU the SR verifies that the functions are not bypassed when power is > 801.6 MWt.
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, function 2.a	Revises the allowable value (AV) for Simulated Thermal Power - High (for two loop operation) from < 0.66W + 61.6 percent RTP to < 0.55W + 61.5 percent RTP	(Note: This change assumes approval of PRNMS changes previously submitted.) See Enclosure 5, Section 2.4.1.3 and Table 2.4-1. Setpoints were determined using an NRC approved methodology based on the change to the Analytical Limit.
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, Note (b)	Revises the AV for Simulated Thermal Power - High (for single loop operation) from < 0.66(W - DeltaW) + 61.6 percent RTP to < 0.55(W - DeltaW) + 61.5 percent RTP.	(Note: This change assumes approval of PRNMS changes previously submitted.) See Enclosure 5, Section 2.4.1.3 and Table 2.4-1. Setpoints were determined using an NRC approved methodology based on the change to the Analytical Limit.

Table 1 Monticello Proposed Operating License and Technical Specification Changes		
TS Section	**Description of Change**	**Basis for Change**
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, function 8	Revises the Applicable Modes or Other Specified Conditions from 45 percent RTP to 40 percent RTP.	Revises the value for the Limit to maintain the value approximately unchanged in thermal power. At CLTP, 45 percent RTP = 798.8 MWt. At EPU 801.6 MWt = 40 percent RTP. Use of 40 percent RTP is slightly less conservative but supported by analysis. See Enclosure 5, Section 2.4.1.3. At CLTP the SR verifies that the functions are not bypassed when power is > 798.8 MWt. At EPU the SR verifies that the functions are not bypassed when power is > 801.6 MWt.
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, function 9	Revises the Applicable Modes or Other Specified Conditions from 45 percent RTP to 40 percent RTP.	Revises the value for the Limit to maintain the value approximately unchanged in thermal power. At CLTP, 45 percent RTP = 798.8 MWt. At EPU 801.6 MWt = 40 percent RTP. Use of 40 percent RTP is slightly less conservative but supported by analysis. See Enclosure 5, Section 2.4.1.3. At CLTP the SR verifies that the functions are not bypassed when power is > 798.8 MWt. At EPU the SR verifies that the functions are not bypassed when power is > 801.6 MWt.

Table 1 Monticello Proposed Operating License and Technical Specification Changes		
TS Section	**Description of Change**	**Basis for Change**
3.5.1, Emergency Core Cooling System (ECCS) and Reactor Core Isolation Cooling System (RCIC), current Action K	Delete current Action K and renumber subsequent Actions (L and M) accordingly.	Current Action K permits one Automatic Depressurization System (ADS) valve to be inoperable in combination with low pressure ECCS injection/spray subsystems. The ECCS/LOCA analysis supporting EPU does not support inoperability of an ADS valve in combination with other ECCS components or subsystem. The CLTP analysis assumes only two of the three ADS valves are operable and applies the single failure criterion from that point. Using this assumption, the CLTP analysis includes one inoperable ADS valve in combination with other ECCS components. The EPU analysis assumes the three ADS valves are operable and applies the single failure criterion from that point. Using this assumption, the EPU analysis does not include an ADS valve inoperable in combination with any other ECCS component. Since it is not addressed in the EPU analysis, the TS allowance cannot be retained.

Table 1 Monticello Proposed Operating License and Technical Specification Changes		
TS Section	**Description of Change**	**Basis for Change**
3.5.1, Emergency Core Cooling System (ECCS) and Reactor Core Isolation Cooling System (RCIC), entry conditions, current Action L	Modify 3rd entry condition for current Action L (renumbered to be Action K) to require placing the unit in Mode 3 with reactor steam pressure ≤ 150 psig when the High Pressure Coolant Injection (HPCI) System in combination with other ECCS components or subsystems without regard to operability of ADS valves.	The ECCS/LOCA analysis supporting EPU does not support inoperability of an ADS valve in combination with any other ECCS components or subsystem. The ECCS/LOCA analysis supporting EPU does not support inoperability of an ADS valve in combination with other ECCS components or subsystem. The CLTP analysis assumes only two of the three ADS valves are operable and applies the single failure criterion from that point. Using this assumption, the CLTP analysis includes one inoperable ADS valve in combination with other ECCS components. The EPU analysis assumes the three ADS valves are operable and applies the single failure criterion from that point. Using this assumption, the EPU analysis does not include an ADS valve inoperable in combination with any other ECCS component. Since it is not addressed in the EPU analysis, the TS allowance cannot be retained.

Table 1 Monticello Proposed Operating License and Technical Specification Changes		
TS Section	**Description of Change**	**Basis for Change**
3.5.1, Emergency Core Cooling System (ECCS) and Reactor Core Isolation Cooling System (RCIC), entry conditions, current Action L	Added a 4th entry condition for current Action L to require placing the unit in Mode 3 with reactor steam pressure ≤ 150 psig when an ADS valve in combination with other ECCS components or subsystems without regard to operability of the HPCI System	The ECCS/LOCA analysis supporting EPU does not support inoperability of an ADS valve in combination with any other ECCS components or subsystem. The ECCS/LOCA analysis supporting EPU does not support inoperability of an ADS valve in combination with other ECCS components or subsystem. The CLTP analysis assumes only two of the three ADS valves are operable and applies the single failure criterion from that point. Using this assumption, the CLTP analysis includes one inoperable ADS valve in combination with other ECCS components. The EPU analysis assumes the three ADS valves are operable and applies the single failure criterion from that point. Using this assumption, the EPU analysis does not include an ADS valve inoperable in combination with any other ECCS component. Since it is not addressed in the EPU analysis, the TS allowance cannot be retained.

Table 1 Monticello Proposed Operating License and Technical Specification Changes		
TS Section	**Description of Change**	**Basis for Change**
SR 3.6.1.3.12	Modify acceptance surveillance requirement (b) to reduce the leakage limit from ≤ 77 scfh to 75.3 scfh.	The existing limit is based on the proportionality of the leakage limit at the reduced test pressure (25 psig) to 100 scfh at P_a. [77 = (100/√42) x (√25)] The revised limit is based on maintaining the same relationship based on the test pressure (25 psig) to the associated leakage limit. [75.3 = (100/√44.1) x (√25)]
SR 3.6.1.3.13	Modify acceptance surveillance requirement (b) to reduce the leakage limit from ≤ 154 scfh to 150.6 scfh.	The existing limit is based on the proportionality of the leakage limit at the reduced test pressure (25 psig) to 200 scfh at P_a. [154 = (200/√42) x (√25).] The revised limit is based on maintaining the same relationship based on the test pressure (25 psig) to the associated leakage limit. [150.6 = (200/√44.1) x (√25)]
5.5.11.a	Change word exception to exceptions.	Editorial correction because more than 1 exception is listed.
5.5.11.b	Revise the value of P_a from 42 psig to 44.1 psig.	See Enclosure 5, Section 2.6.1.

Table 2 Monticello Technical Specifications Unchanged References to Percent RTP	
TS Section	**Bases for No Change**
1.3, Completion Times	Example 1.3-6, contain "% RTP," this is only an example used to clarify Completion Time requirements and does not need to change for EPU.
1.4, Frequency	Examples 1.4-2 and 1.4-3 contain "% RTP," these are only examples used to clarify frequency requirements and do not need to change for EPU.
2.1.1.1, Reactor Core SLs	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.1.3, Control Rod OPERABILITY, Note to Condition D	Maintaining the value at 10 percent RTP is more conservative in terms of absolute power.
3.1.4, Control Rod Scram Times, SR 3.1.4.1 Frequency and SR 3.1.4.4 1st and 2nd Frequency	The 40 percent RTP remains unchanged even though the actual power level will be slightly higher than the pre-EPU condition. 40 percent RTP is greater than the Rod Worth Minimizer low power set point (< 10 percent RTP) such that Control Rod Drive positioning is less restricted and scram testing is easier to perform. Reactor dome pressure is expected to be greater than 800 psig, which allows testing conditions that are closer to normal operating pressure. Additionally 40 percent RTP is well below 100 percent RTP.
3.1.6, Rod Pattern Control, Applicability	Maintaining the value at 10 percent RTP is more conservative in terms of absolute power.
3.2.1, APLHGR, Applicability	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.2.1, APLHGR, Required Action B.1	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.2.1, APLHGR, SR 3.2.1.1 1st Frequency	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.2.2, MCPR, Applicability	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.

Table 2 Monticello Technical Specifications Unchanged References to Percent RTP	
TS Section	**Bases for No Change**
3.2.2, MCPR, Required Action B.1	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.2.2, MCPR, SR 3.2.1.1 1st Frequency	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.2.3, LHGR, Applicability	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.2.3, LHGR, Required Action B.1	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.2.3, LHGR, SR 3.2.1.1 1st Frequency	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.3.1.1, RPS Instrumentation, Required Action J.1	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.3.1.1, RPS Instrumentation, SR 3.3.1.1.2 and associated note	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.3.1.1, RPS Instrumentation, SR 3.3.1.1.16	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, Function 2.a, Allowable Value	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.3.1.1, RPS Instrumentation, Table 3.3.1.1-1, Function 2.f, Applicable Modes or Other Specified Conditions	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.3.2.1, Control Rod Block Instrumentation, SR 3.3.2.1.2	Maintaining the value at 10 percent RTP is more conservative in terms of absolute power.
3.3.2.1, Control Rod Block Instrumentation, SR 3.3.2.1.3	Maintaining the value at 10 percent RTP is more conservative in terms of absolute power.

Table 2 Monticello Technical Specifications Unchanged References to Percent RTP	
TS Section	**Bases for No Change**
3.3.2.1, Control Rod Block Instrumentation, SR 3.3.2.1.5.a, b, and c; Table 3.3.2.1-1, Notes to Applicable Mode or Other Specified Conditions (a), (b), (c), (d), and (e)	The low power setpoint (LPSP), intermediate power setpoint (IPSP), and high power setpoint (HPSP) for the Rod Block Monitor do not change for EPU.
3.3.2.1, Control Rod Block Instrumentation, Table 3.3.2.1-1, Note (f)	Maintaining the value at < 10 percent RTP is more conservative in terms of absolute power.
3.3.2.2, Feedwater Pump and Main Turbine High Water Level Trip Instrumentation, Applicability	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.3.2.2, Feedwater Pump and Main Turbine High Water Level Trip Instrumentation, Required Action C.2	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.4.2, Jet Pumps, SR 3.4.2.1, Note 2	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.
3.6.2.1, Suppression Pool Average Temperature, LCO a, b, and c	At 1 percent RTP, heat input is approximately equal to normal system heat. The difference in heat input between CLTP and EPU is slightly greater than 2 MWt. The change is not significant.
3.6.3.1, Primary Containment Oxygen Concentration, Applicability (a and b) and Required Action B	The 15 percent RTP establishes the start of a 24 hour window for completing inerting and de-inerting the containment during plant startups and shutdowns. This specification for drywell oxygen concentration does not change for EPU. As long as reactor power is ≤ 15% RTP, the potential for an event that generates significant hydrogen and oxygen is low and the primary containment need not be inert. The probability of an event that generates hydrogen occurring within the first 24 hours of a startup, or within the last 24 hours before a shutdown, is low enough that these "windows," are justified. Therefore, the current 15 percent RTP value does not need to be changed.
3.7.7, Main Turbine Bypass System, Applicability	See Enclosure 5, Section 2.8.2.2, Fuel Thermal Margin Monitoring Threshold. The threshold for thermal monitoring does not require any change.

3.0 BACKGROUND

Extended Power Uprate

MNGP was originally licensed to operate at a maximum power level of 1,670 MWt. Northern States Power (NSP), the predecessor to NMC, has performed one previous power uprate. This previous uprate increased the licensed thermal power by approximately 6.3 percent (References 5, 6, and 7).

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

In March 2003, the NRC approved the use of the CLTR (Reference 1) as a basis for power uprate license amendment requests, subject to limitations specified in the CLTR and in the associated NRC safety evaluation. The limitations relate to license amendment requests that may not be pursued concurrently with the power uprate request. NMC is not concurrently pursuing any changes associated with the specified limitations.

A higher steam flow is achieved by increasing the reactor power along specified control rod and core flow lines. A limited number of operating parameters are changed, some setpoints are adjusted, and instruments are recalibrated. Plant procedures are revised, and tests similar to some of the original startup tests are performed. Modifications to power generation equipment will be implemented as necessary. See Enclosure 8 for a list of planned modifications.

Detailed evaluations of the reactor, engineered safety features, power conversion, emergency power, support systems, environmental issues, and design basis accidents were performed and are provided in Enclosure 5. These evaluations demonstrate that MNGP can safely operate at 2,004 MWt.

Containment Analysis Methods Changes

The DBA-LOCA long-term containment response is described in Section 5.2.3.2 of the USAR. The supporting analysis was performed by GE with the SHEX

code, which is the MNGP current licensing basis methodology (except for station blackout). In that analysis, passive heat sinks were not credited, the RHR heat exchanger K-value is a fixed value at 147 Btu/sec-°F, and the wetwell air space is in thermal equilibrium with the suppression pool, (except for NPSH cases). The EPU containment analysis takes credit for passive heat sinks, assumes a variable heat exchanger K-value, and assumes a mechanistic heat and mass transfer from the suppression pool surface to the wetwell airspace after 30 seconds. The EPU containment analysis for station blackout also uses SHEX. The containment analysis is described in Enclosure 5, Sections 2.6.1 and 2.6.5.

Increase in Credit for Containment Overpressure for Low Head ECCS Pumps

The NRC, by its SER dated June 2, 2004 (Reference 8), approved use of containment overpressure for the low head ECCS pumps for DBA-LOCA and Appendix R for MNGP. The current licensing basis does not specifically credit containment overpressure for the anticipated transient without scram (ATWS) and small steam line break accident (SBA) events. The EPU analysis credits containment overpressure for DBA-LOCA, Appendix R, ATWS, and SBA events as described in Enclosure 5, Section 2.6.5.

Reactor Internal Pressure Differentials for the Steam Dryer

The EPU method of establishing steam dryer differential pressures uses a different method from that used in the previous uprate. Specific details include information proprietary to GE Hitachi and are described in Enclosure 5, Section 2.2.3.

4.0 TECHNICAL ANALYSIS

Extended Power Uprate

Enclosure 5 summarizes the results of the significant safety evaluations performed that justify uprating the licensed thermal power at MNGP. Enclosure 5 is based on the CLTR and formatted in accordance with RS-001, "Review Standard for Extended Power Uprates." These evaluations demonstrate that MNGP can safely operate at 2,004 MWt.

Summary

The generation and supply of higher steam flow for the turbine-generator accomplishes an increase in electrical output of a BWR plant. Most BWR plants, including MNGP, as currently licensed, have an as-designed equipment and system capability to accommodate steam flow rates at least 5 percent above the original rating. In addition, continuing improvements in the analytical techniques (computer codes and data) based on several decades of BWR safety technology, plant performance feedback, and improved fuel and core designs have resulted in a significant increase in the design and operating margins between calculated safety analysis results and the licensing limits. These available safety analyses

differences, combined with the excess as-designed equipment, system and component capabilities, provide BWR plants the capability to achieve an increase in their thermal power ratings of between 5 and 20 percent without major NSSS hardware modifications, and provide for power increases to 20 percent with limited hardware modifications, with no significant increase in the hazards presented by the plant as approved by the NRC at the original license stage.

The plan for achieving higher power is to extend the power to flow map along the standard maximum extended load line limit analysis power to flow upper boundary. The extension of the power-to-flow map does not require an increase in the maximum core flow limit or operating pressure over the pre-EPU values.

Discussions of Issues Being Evaluated

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

EPU Analysis Basis

NSP, the predecessor to NMC, has performed one previous power uprate. This uprate increased the licensed thermal power by approximately 6.3 percent (References 5, 6, and 7). The key thermal power levels are as follows:

- The original licensed thermal power (OLTP) is 1,670 MWt.
- The rerate licensed thermal power of 1,775 MWt is the current licensed thermal power.
- The requested maximum authorized power level of this license amendment request is 1,870 MWt. This thermal power level conservatively correlates to the electrical power cited in the interconnection request for the first implementation phase of the EPU (620 MWe net generation to the grid).
- The EPU thermal power is 2,004 MWt.
- The analysis thermal power is 1.02 x 2,004 MWt or 2,044 MWt.

Thus, MNGP is currently licensed for operation up to 1,775 MWt, and the current safety analyses are based on this value or greater[1]. The EPU RTP level included in this evaluation is 120 percent of the original licensed thermal power level. The EPU safety analyses are based on a power level of 1.02 times the

[1] Most of the analyses performed for the previous uprate and approved by the SER used 1,880 MWt (112.6% of 1670 MWt).

EPU power level unless the Regulatory Guide 1.49 (Reference 12) two percent power factor is already accounted for in the analysis methods.

Fuel Thermal Limits

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

Makeup Water Sources

The BWR design concept includes a variety of ways to pump water into the reactor vessel to mitigate all types of events. There are numerous safety-related and non-safety-related cooling sources. The safety-related cooling water sources alone would maintain core integrity by providing adequate cooling water. EPU does not result in a change in the number of available water sources, nor does it change the selection of those assumed to function in the safety analyses. NRC-approved methods were used for analyzing the performance of the ECCS during loss-of-coolant-accidents. EPU results in an increase in decay heat, and thus, the time required to cooldown to cold shutdown conditions increases. The existing cooling capacity can bring the MNGP unit to cold shutdown within a time span that continues to meet plant safety and regulatory operational requirements.

Design Basis Accidents

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

Several of the most significant licensing assessments are based on the LOCA. These assessments are:

1. Challenges to Fuel

   The ECCS are described in Section 6.2 of the MNGP Updated Safety Analysis Report (USAR). The ECCS performance evaluation described in Enclosure 5, Section 2.8.5.6.2 demonstrates the continued conformance to the acceptance criteria of 10 CFR 50.46. The change in peak clad temperature (PCT) for EPU is insignificant compared to the large amount by

which the results are below the regulatory criteria. Therefore, the ECCS safety margin is not affected by EPU.

2. Challenges to the Containment

Enclosure 5, Table 2.6-1 provides the results of analyses of the MNGP containment response to the most severe LOCAs. The effect of EPU on the peak values for containment pressure and temperature confirms the suitability of the plant for operations at EPU RTP. Also, the effects of EPU on the conditions that affect the containment dynamic loads are evaluated in Enclosure 5, Section 2.6, and the results were satisfactory for EPU operation. Where plant conditions with EPU are within the range of conditions used to define the current dynamic loads, current safety criteria are met and no further structural analysis is required. The change in short-term containment response is acceptable. Because there will be more residual heat with EPU, the containment long-term response increases. However, containment pressures and temperatures remain below their design limits following any design basis accident, and thus, the results for the containment and its cooling systems are satisfactory for EPU operation. The increase in the calculated post LOCA suppression pool temperature above the currently assumed peak temperature was evaluated and determined to be acceptable. The design temperature for torus attached piping will be increased to bound the new higher peak suppression pool temperatures. The NPSH requirements for the residual heat removal and core spray pumps were analyzed at the design required flow rates during the short-term and long-term DBA-LOCA ECCS pump operation, calculated suppression pool temperature, and the design basis suction strainer debris loading. The inputs in the ECCS NPSH calculations for friction loss, static head, and suction strainer debris loading are not changed and are not affected by EPU. ECCS low pressure pumps (RHR and Core Spray) will continue to require overpressure to be credited to satisfy pump NPSH requirements.

3. Design Basis Accidents Radiological Consequences

The results of source term and radiological consequence analyses are provided in Enclosure 5, Section 2.9. The magnitude of the potential radiological consequences is dependent upon the quantity of fission products released to the environment, the atmospheric dispersion factors, and the dose exposure pathways. The atmospheric dispersion factors and the dose exposure pathways do not change. Therefore, the only factor that could influence the magnitude of the consequences is the quantity of activity released to the environment. This quantity is a product of the activity released from the core and the transport mechanisms between the core and the effluent release point. The radiological consequences of a LOCA inside containment, Main Steam Line Break Accident (MSLBA) outside containment, Control Rod Drop Accident (CRDA) and Fuel Handling Accident (FHA) are reevaluated for EPU. The dose consequence analyses demonstrate that the dose criteria of 10 CFR 50.67 are met for the EPU power level.

Anticipated Operational Occurrence Analyses

Anticipated Operational Occurrences (AOOs) are evaluated against the Safety Limit Minimum Critical Power Ratio (SLMCPR). The SLMCPR is determined using NRC approved methods. The limiting transients are core specific and are analyzed for each reload fuel cycle.

As described in Section 2.8.5 of Enclosure 5, the limiting AOOs have been evaluated for the EPU RTP conditions. The results of the EPU AOO evaluations demonstrate that EPU RTP operation can be safely implemented consistent with the bases for the TS Power Distribution Limits. Licensing acceptance criteria are not exceeded. Continued compliance with the SLMCPR and other applicable fuel design limits will be confirmed on a cycle specific basis. Therefore, the margin of safety is not affected by EPU.

Combined Effects

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

The DBA that produces the highest peak clad temperature does not result in more severe damage to the fuel than assumed in the MNGP off-site and control room dose evaluations. The DBA that produces the maximum containment pressure does not result in leak rates to the environment that are greater than assumed in the off-site and control room dose evaluations. Thus, the post accident doses calculated in conformance with Regulatory Guide 1.183 (Reference 13) and SRP Section 15.0.1 (Reference 4) provide bounding DBA results that envelope the greatest challenge to fuel and containment.

Environmental Qualification

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

Balance-of-Plant

The balance-of-plant (BOP) systems and equipment used to perform safety-related and normal operation functions have been reviewed for EPU in a manner

comparable to that for safety related NSSS systems/equipment. Extended power uprate operation for BOP systems and equipment is supported by either generic or plant specific evaluations, which includes modifications made (or planned) to BOP components.

Probabilistic Risk Assessment

Enclosure 5, Section 2.13 and Enclosure 15 describes the results of Level I and Level 2 Probabilistic Risk Assessments (PRAs) performed for EPU conditions. Using the NRC guidelines established in Regulatory Guide 1.174 (Reference 2) and the calculated results from the Level I PRA, the best estimate for the MNGP CDF risk increase due to the EPU (7.89E-06/yr) is in Region III (i.e., very small risk changes). The best estimate for the LERF increase (3.94E-07/yr) is also in Region III range of Regulatory Guide 1.174.

Primary Containment Leakage Rate Testing Program

Surveillance Requirements SR 3.6.1.1.1, SR 3.6.1.2.1, SR 3.6.1.3.11, SR 3.6.1.3.12, and SR 3.6.1.3.13 require that primary containment leakage rates be demonstrated in accordance with the Primary Containment Leakage Rate Testing Program. The testing program is required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J and is described in TS 5.5.11. Test intervals are established on a performance basis in accordance with 10 CFR 50 Appendix J, Option B, as modified by approved exemptions.

The Type A integrated leak rate test and the Type B and C local leak rate tests are performed at the calculated peak containment pressure (Pa). Pa increases to 44.1 psig for the EPU. Therefore, TS 5.5.11 is being revised to reflect the change. The results of the integrated leak rate test (ILRT) and local leak rate testing (LLRT) performed in the 2007 refueling outage indicated significant margin to acceptance limits. Based on the substantial margin between the recent results and the acceptance limits discussed above, NMC proposes to not re-perform all the leak rate tests at the higher Pa before implementation of the EPU. Proposed License Condition 2.C.(13) would allow leak rate tests required by Surveillance Requirements SR 3.6.1.1.1, SR 3.6.1.2.1, SR 3.6.1.3.11, SR 3.6.1.3.12, and SR 3.6.1.3.13 to be considered to be met per SR 3.0.1 until the next scheduled performance. This would preclude having to perform the affected leak rate tests before their next scheduled performance solely for the purpose of documenting compliance. The allowance provided in License Condition 2.C.(13) would not supersede that aspect of SR 3.0.1 that governs cases where it is believed that, if the SR were performed, it would not be met.

Containment Analysis Methods Change

The existing computer program of record for the MNGP DBA-LOCA long-term suppression pool temperature response is the GE SHEX methodology, and thus, the continued use of this methodology is consistent with the MNGP current licensing basis, except for station blackout. The EPU containment analysis for

SBO uses SHEX. However, three analytical elements, which are consistent with GE standards for containment re-evaluations, are not part of the MNGP current licensing bases. These elements are: 1) crediting the presence of passive containment heat sinks heat sinks for the DBA-LOCA analysis; 2) allowing the RHR heat exchanger capability (K-Value, BTU/sec°F) to vary as function of hot inlet temperature for the long term DBA-LOCA analysis; (3) assuming mechanistic heat and mass transfer from the suppression pool surface to the wetwell airspace after 30 seconds for the long term DBA-LOCA containment analysis.

The practice of crediting selected passive heat sinks is discussed in Branch Technical Position BTP 6-2 (Reference 3). The current MNGP containment analysis does not credit passive heat sinks. The MNGP EPU analysis credits structural steel, and the containment liner. The use of these heat sinks is consistent with the limitations of the SHEX code, and provides a realistic model of this natural phenomenon.

The MNGP EPU long-term containment analyses with suppression pool cooling was modeled using an RHR heat exchanger K value that varies as a function of the suppression pool water temperature. This provides a more accurate prediction of the heat exchanger performance and therefore, of the long-term containment response. The difference between the maximum and minimum calculated value for K using this approach is only 3.5 percent. Consequently, the effect on heat exchanger performance of using this approach versus using a constant value for K is relatively small. Additionally, there is no difference between the methodology used to calculate the varying K values and the constant K values. In either case the values for K have been conservatively derived using design assumptions including fouling factors. Confirmation of the ability of the RHR heat exchangers to support the K values used is verified annually by performance of a heat exchanger efficiency test. The RHR heat exchanger performance (K value) modeled in the MNGP EPU long-term containment analysis provides more accuracy but maintains conservatism.

The long-term DBA-LOCA containment analyses use assumptions that include mechanistically modeling heat and mass transfer between the wetwell airspace and the suppression pool to more realistically represent the containment pressure response and better reflect the effects of different modes of RHR operation on the containment response. For the DBA-LOCA with RHR suppression pool cooling mode modeled, the first 30 seconds of the DBA-LOCA thermodynamic equilibrium is modeled assuming thermodynamic equilibrium between the pool water and wetwell airspace. This assumption is based on expected conditions associated with the vigorous mixing and pool agitation, which occurs during the early blowdown period. It is assumed that after this period, the amount of mixing between the pool surface and wetwell airspace is reduced and mechanistic modeling of the heat and mass transfer is more appropriate. This approach allows the effects of heat sinks, which are modeled for these analyses to be represented in the results. It should be noted that there is little effect of using either modeling approach on the peak suppression pool

temperature since the amount of energy transferred to the wetwell airspace is small relative to the energy added to the suppression pool. Also, as indicated by the results of the DBA-LOCA with RHR suppression pool cooling mode, the peak long-term wetwell temperature is within a few degrees of the peak suppression pool temperature, so the effect of assuming mechanistic heat and mass transfer on the long-term wetwell peak temperature and pressure values is not significant.

For the DBA-LOCA with containment sprays, this approach is required to allow an accurate representation of the effect of the sprays on wetwell pressure and temperature. This is of main concern for the DBA-LOCA analyses with containment sprays, which provide the suppression pool temperature and wetwell pressure input to NPSH evaluations. Modeling mechanistic heat and mass transfer for this event produces conservatively low values of wetwell pressure, which minimizes the available NPSH margin.

Increase in Credit for Containment Overpressure for Low Head ECCS Pumps

Enclosure 5, Section 2.6.5 includes the results of analysis regarding NPSH margins for low pressure ECCS pumps. The evaluation of NPSH margins for the low pressure ECCS pumps indicates no increase in credit allowable for containment overpressure is required for the DBA-LOCA case. The assumptions used in containment response analyses used in the evaluation of NPSH margin maximized the suppression pool temperature and minimized the available containment pressure. The debris loading on the suction strainers for EPU is the same as the CLTP condition. The assumptions in the NPSH calculations for friction loss, static head, and flow are consistent with previous analyses.

For LOCA, Table 2.6-2 and Figure 2.6-1A and Figure 2.6-1B provide the results of the short-term and long-term containment response, including suppression pool temperature, required containment pressure to satisfy the NPSH Required (NPSHR), and available wetwell pressure based on the use of 3 percent NPSHR curves. Figure 2.6-1C is provided for comparison and shows the results if based on the use of one percent NPSHR curves except the short term core spray (CS) NPSHR that utilized the three percent curve value. The short and long-term analysis indicates that overpressure is available from the beginning of the event until the end of the event with Technical Specification containment leakage assumed (1.2 percent/day).

For Appendix R, Enclosure 5, Table 2.6-3 and Figure 2.6-2 (case 1) and Table 2.6-4 and Figure 2.6-3 (case 2) provide the results of the containment response, including suppression pool temperature, the containment pressure necessary to satisfy the NPSHR, and the available wetwell pressure. NPSHR values are based on the one percent NPSHR curves.

For ATWS, Enclosure 5, Tables 2.6-6, 2.6-7, and 2.6-8 and Figures 2.6-4, 2.6-5 and 2.6-6 provide the results of the containment response including suppression pool temperature, required containment pressure to satisfy the NPSHR, and available wetwell pressure, for the Pressure Regulator Failed – Open (PRFO)

case 1, PRFO case 2, and the loss of offsite power case respectively. NPSHR values are based on the one percent NPSHR curves.

For SBA Enclosure 5, Table 2.6-9 and Figure 2.6-7 provide the results of the containment response including suppression pool temperature, required containment pressure to satisfy the NPSHR, and available wetwell pressure, for the SBA event. NPSHR values are based on the one percent NPSHR curves.

Based on the above, Monticello is requesting approval of increased maximum overpressure credit from 20.36 psia to 21.2 psia to bound NPSH requirements for any analyzed design basis or license basis event.

For each event the analyses indicates sufficient containment overpressure is available to satisfy the NPSHR for the associated low pressure ECCS pumps using conservative methodology that maximized the suppression pool temperature and minimized the available containment pressure.

Reactor Internal Pressure Differentials for the Steam Dryer

The technical bases for the change in steam dryer RIPDs used in the reactor vessel internal load evaluation includes information proprietary to GE Hitachi and are discussed in Enclosure 5, Section 2.2.3.

5.0 REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration

In accordance with the requirements of 10 CFR 50.90, the Nuclear Management Company, LLC (NMC) requests an amendment for an extended power uprate. NMC has evaluated the proposed amendment in accordance with 10 CFR 50.91 against the standards in 10 CFR 50.92 and has determined that the operation of the facility in accordance with the proposed amendment presents no significant hazards. NMC's evaluation against each of the criteria in 10 CFR 50.92 follows.

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

Extended Power Uprate

Response: No.

The probability (frequency of occurrence) of Design Basis Accidents occurring is not affected by the increased power level, because Monticello Nuclear Generating Plant (MNGP) continues to comply with the regulatory and design basis criteria established for plant equipment. A probabilistic risk assessment demonstrates that the calculated core damage frequencies do not significantly change due to Extended Power Uprate (EPU). Scram setpoints (equipment

settings that initiate automatic plant shutdowns) are established such that there is no significant increase in scram frequency due to EPU. No new challenges to safety-related equipment result from EPU.

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

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

Challenges to the containment have been evaluated, and the containment and its associated cooling systems continue to meet the current licensing basis. The increase in the calculated post LOCA suppression pool temperature above the currently assumed peak temperature was evaluated and determined to be acceptable. Radiological release events (accidents) have been evaluated, and have been shown to meet the guidelines of 10 CFR 50.67.

Containment Analysis Methods Change

Response: No.

The use of passive heat sinks, variable RHR heat exchanger capability K-value, and mechanistic heat and mass transfer from the suppression pool surface to the wetwell airspace after 30 seconds for the long term design basis accident loss of coolant accident (DBA-LOCA) containment analysis are not relevant to accident initiation, but rather, pertain to the method used to accurately evaluate postulated accidents. The use of these elements does not, in any way, alter existing fission product boundaries, and provides a conservative prediction of the containment response to DBA-LOCAs. Therefore, the containment analysis method change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

Increase in Credit for Containment Overpressure for Low Head Emergency Core Cooling System (ECCS) Pumps

Response: No.

These changes update parameters used in the MNGP safety analyses and expand the range and scope of the analyses. This will result in a more realistic

analysis of available containment overpressure under design basis accident conditions. The updated analyses affect only the evaluation of previously reviewed accidents. No plant structure, system, or component (SSC) is physically affected by the updated and expanded analyses. No method of operation of any plant SSC is affected. Therefore, there is no significant increase in the probability or consequence of a previously evaluated accident.

Reactor Internal Pressure Differentials (RIPDs) for the Steam Dryer

Response: No.

The revised steam dryer RIPDs are used in evaluating loads in reactor vessel internals for various conditions (i.e., during normal, upset and faulted conditions). The values more accurately represent the actual plant configuration. No plant structure, system, or component (SSC) is physically affected by the updated and expanded analyses. No method of operation of any plant SSC is affected. Therefore, there is no significant increase in the probability or consequence of a previously evaluated accident.

The analyses supporting the above evaluations were performed at the EPU power level of 2,004 MWt, which bounds this license amendment request to operate at 1,870 MWt. Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

Extended Power Uprate

Response: No.

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

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

Containment Analysis Methods Change

Response: No.

The use of passive heat sinks, variable RHR heat exchanger capability K-value, and mechanistic heat and transfer from the suppression pool surface to the wetwell airspace after 30 seconds for the long term DBA-LOCA containment analysis are not relevant to accident initiation, but pertain to the method used to evaluate currently postulated accidents. The use of these analytical tools does not involve any physical changes to plant structures or systems, and does not create a new initiating event for the spectrum of events currently postulated. Further, they do not result in the need to postulate any new accident scenarios. Therefore, the containment analysis method change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

Increase in Credit for Containment Overpressure for Low Head ECCS Pumps

Response: No.

The proposed change involves the updating and expansion in scope of the existing design bases analysis with respect to the available containment overpressure. No new failure mode or mechanisms have been created for any plant SSC important to safety nor has any new limiting single failure been identified as a result of the proposed analytical changes. Therefore, the change to containment overpressure credited for low pressure ECCS pumps does not create the possibility of a new or different kind of accident from any accident previously evaluated.

Reactor Internal Pressure Differentials for the Steam Dryer

Response: No.

The revised steam dryer RIPDs are used in evaluating loads in reactor vessel internals for various conditions (i.e., during normal, upset and faulted conditions). The steam dryer RIPDs are not relevant to accident initiation, but only pertain to the method used to evaluate reactor vessel internals loads. The revised steam dryer RIPD values more accurately represent the actual plant configuration. Therefore, the change to steam dryer RIPDs does not create the possibility of a new or different kind of accident from any accident previously evaluated.

The analyses supporting the above evaluations were performed at the EPU power level of 2,004 MWt, which bounds this license amendment request to operate at 1,870 MWt. Therefore, the proposed changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

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

Extended Power Uprate

Response: No.

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

Containment Analysis Methods Change

Response: No.

The use of passive heat sinks, variable RHR heat exchanger capability K-value, and mechanistic heat and mass transfer from the suppression pool surface to the wetwell airspace after 30 seconds for the long term DBA-LOCA containment analysis are realistic phenomena and provide a conservative prediction of the plant response to DBA-LOCAs. The increase in pressure and temperature are relatively small and are within design limits. Therefore, the containment analysis methods change does not involve a significant reduction in the margin of safety.

Increase in Credit for Containment Overpressure for Low Head ECCS Pumps

Response: No.

The proposed changes revise containment response analytical methods and scope for containment pressure to assist in ECCS pump net positive suction head (NPSH). The changes are still based on conservative but more realistic analysis of available containment overpressure determined using analysis methods that minimize containment pressure and maximize suppression pool temperature. These changes do not constitute a significant reduction in the margin of safety.

Reactor Internal Pressure Differentials for the Steam Dryer

Response: No.

The revised steam dryer RIPDs are used in evaluating loads in reactor vessel internals for various conditions (i.e., during normal, upset and faulted conditions). The revised steam dryer RIPD values more accurately represent the actual plant

configuration. The changes are still conservative but more accurately represent the MNGP configuration. These changes do not constitute a significant reduction in the margin of safety.

The analyses supporting the above evaluations were performed at the EPU power level of 2,004 MWt, which bounds this license amendment request to operate at 1,870 MWt. Therefore, the proposed changes do not involve a significant reduction in a margin of safety.

Based on the considerations above, the NMC has determined that operation of the facility in accordance with the proposed change does not involve a significant hazards consideration as defined in 10 CFR 50.92(c), in that it does not: (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety.

5.2 Applicable Regulatory Requirements

5.2.1 Analysis

Extended Power Uprate

10 CFR 50.36 (d)(2)(ii) Criterion 2, requires that TS LCOs include process variables, design features, and operating restrictions that are initial conditions of design basis accident analysis. The Technical Specifications ensure that the MNGP system performance parameters are maintained within the values assumed in the safety analyses. The Technical Specification changes are supported by the safety analyses and continue to provide a level of protection comparable to the current Technical Specifications. Applicable regulatory requirements and significant safety evaluations performed in support of the proposed changes are described in Enclosure 5.

Containment Analysis Methods Change

The MNGP principal design criteria with respect to containment are specified in USAR section 1.2.4. The applicable criteria in this section are specified in USAR sections 1.2.4.a and 1.2.4.b.

USAR Section 1.2.4.a requires that a primary containment system be provided that is designed, fabricated and erected to accommodate, without failure, the pressures and temperatures resulting from or subsequent to the double-ended rupture, or equivalent failure of any coolant pipe within the primary containment. The evaluations described in Enclosure 5, Section 2.6 demonstrate that containment parameters stay within their design limits.

Section 1.2 of the Monticello USAR contains principal design criteria specific to MNGP. Section 1.2.4.b of the USAR states, "Provision is made both for the

removal of energy from within the primary containment and/or such other measures as may be necessary to maintain integrity of the primary containment system as long as necessary following the various postulated design-basis loss-of-coolant accidents." The evaluations described in Enclosure 5, Section 2.6 demonstrate that containment parameters stay within their design limits.

Increase in Credit for Containment Overpressure for Low Head ECCS Pumps

Section 1.2 of the Monticello USAR contains principal design criteria specific to MNGP. Section 1.2.4.b of the USAR states, "Provision is made both for the removal of energy from within the primary containment and/or such other measures as may be necessary to maintain integrity of the primary containment system as long as necessary following the various postulated design-basis loss-of-coolant accidents."

Regulatory Guide (RG) 1.82, Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident, Revision 3 (Reference 11) is not part of MNGP's licensing basis. However its provisions may be useful as guidance. This RG recognizes that it may not be practicable to alter the design of an operating reactor. Therefore, some overpressure may be needed to assure adequate available NPSH. RG 1.82 indicates that containment accident pressure should be conservatively calculated and the amount of credit given for containment overpressure should be minimized.

The proposed increased credit for containment overpressure bounds analyzed design and licensing basis events. The containment response used for NPSH evaluations was calculated using MNGP specific inputs to maximize suppression pool temperature and minimize containment pressure for the DBA LOCA analysis. The containment responses used for NPSH evaluations for Special Events (such as ATWS, SBO, and Appendix R) used MNGP specific nominal inputs to provide realistic maximized suppression pool temperatures and corresponding realistic minimized wetwell pressures.

Reactor Internal Pressure Differentials for the Steam Dryer

Section 1.2 of the Monticello USAR contains principal design criteria specific to Monticello. Section 1.2.1.a of the USAR states, "The plant is designed, fabricated, erected, and operated to produce electrical power in a safe, reliable, and efficient manner and in accordance with applicable codes and regulations."

Section 1.2.2.i of the USAR states, "The reactor core and associated systems are designed to accommodate plant operational transients or maneuvers which might be expected without compromising safety and without fuel damage."

The EPU methodology is based on a more realistic correlation for a BWR3 steam dryer instead of air test data for BWR6 steam dryers. The change methodology for determining steam dryer RIPDs is described in Enclosure 5, Section 2.2.3. The evaluation indicates that the reactor internals and core supports will continue

to meet the requirements of 10 CFR 50.55a and MNGP's current licensing basis following implementation of the proposed EPU.

In conclusion, based on the considerations discussed above, (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

Proposed Changes for Extended Power Uprate

The proposed TS changes required for implementation of EPU meet the requirements for an environmental review as set forth in 10 CFR 51.20, "Criteria for and Identification of Licensing and Regulatory Actions Requiring Environmental Impact Statements." The Environmental Assessment in Enclosure 4 concludes that, "Extended power uprate does not involve any significant impacts to the environment. There are no new significant environmental hazards in addition to those previously evaluated. The environmental impacts and adverse effects identified by the NRC Staff for MNGP operation at 1,670 MWt in the Summary and Conclusions Section of the Final Environmental Statement continue to bound plant operation at extended power uprate conditions. The proposed changes do not, individually or cumulatively, affect the human environment. There is no significant change in the types or amounts of plant effluents. Extended power uprate does not involve significant increases in individual or cumulative occupational radiation exposure." The evaluation described in the Environmental Assessment, Enclosure 4, supports increases in the licensed power level up to 2,004 MWt.

Other Proposed Changes

Containment Analysis Methods Change, Containment Overpressure for NPSH for Low Pressure ECCS Pumps, and Steam Dryer RIPDs

These proposed changes do not involve (i) a significant hazards consideration, (ii), a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, these proposed changes meet the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with these proposed changes.

7.0 References

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

2. USNRC Regulatory Guide 1.174, "An Approach For Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes to The Licensing Basis"

3. Branch Technical Position BTP 6-2, "Minimum Containment Pressure Model For PWR ECCS Performance Evaluation" (NUREG-0800, BTP 6-2), Rev. 3, March 2007

4. Standard Review Plan (SRP) 15.0.1, "Radiological Consequence Analyses Using Alternative Source Terms" Rev. 0, July, 2000

5. Northern States Power letter to NRC, July 26, 1996, License Amendment Request Supporting the Monticello Nuclear Generating Plant Power Rerate Program

6. Northern States Power letter to NRC, December 4, 1997, Revision 1 to License Amendment Request Dated July 26 1996, Supporting the Monticello Nuclear Generating Plant Power Rerate Program

7. NRC Letter to Northern States Power, September 16, 1998, Monticello Nuclear Generating Plant - Issuance of Amendment Re: Power Uprate Program (TAC No. M96238)

8. NRC Letter to Northern States Power, June 2, 2004, Monticello Nuclear Generating Plant - Issuance of Amendment RE: Revised Analyses of Long-Term Containment Response and Net Positive Suction Head (TAC No. MB7185)

9. February 6, 2008, NMC letter to NRC, License Amendment Request: Power Range Neutron Monitoring System Upgrade, ML 080430634

10. RIS-001, Review Standard for Extended Power Uprates, Revision 0, December 2003

11. Regulatory Guide 1.82, Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident, Revision 3

12. Regulatory Guide 1.49, "Power Levels of Nuclear Power Plants," Revision 1, 1973 (Withdrawn[2] -- See 72 FR 36737, 07/05/2007)

[2] The federal register notice states that "Withdrawal of RG 1.49 does not, in and of itself, alter any prior or existing licensing commitments based on its use."

13. Regulatory Guide 1.183, "Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors" July, 2000 ML003716792

Enclosure 2 to L-MT-08-018

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

2. Pursuant to the Act and 10 CFR Part 70, NMC to receive, possess, and use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operations, as described in the Final Safety Analysis Report, as supplemented and amended, and the licensee's filings dated August 16, 1974 (those portions dealing with handling of reactor fuel) and August 17, 1977 (those portions dealing with fuel assembly storage capacity);

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

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

5. Pursuant to the Act and 10 CFR Parts 30 and 70, NMC to possess, but not separate, such byproduct and special nuclear material as may be produced by operation of the facility.

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

1. Maximum Power Level

NMC is authorized to operate the facility at steady state reactor core power levels not in excess of ~~1773~~ megawatts (thermal). 1870

2. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. ~~152~~ are hereby incorporated in the license. NMC shall operate the facility in accordance with the Technical Specifications.

3. Physical Protection

NMC shall implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search

3. Designated staging areas for equipment and materials
4. Command and control
5. Training of response personnel

(b) Operations to mitigate fuel damage considering the following:
1. Protection and use of personnel assets
2. Communications
3. Minimizing fire spread
4. Procedures for implementing integrated fire response strategy
5. Identification of readily-available pre-staged equipment
6. Training on integrated fire response strategy
7. Spent fuel pool mitigation measures

(c) Actions to minimize release to include consideration of:
1. Water spray scrubbing
2. Dose to onsite responders

Insert OL-2.C.13

12. The licensee shall implement and maintain all Actions required by Attachment 2 to NRC Order EA-06-137, issued June 20, 2006, except the last action that requires incorporation of the strategies into the site security plan, contingency plan, emergency plan and/or guard training and qualification plan, as appropriate.

D. NMC shall immediately notify the NRC of any accident at this facility which could result in an unplanned release of quantities of fission products in excess of allowable limits for normal operation established by the Commission.

E. Northern States Power Company 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.

F. NMC shall observe such standards and requirements for the protection of the environment as are validly imposed pursuant to authority established under Federal and State law and as determined by the Commission to be applicable to the facility covered by this renewed facility operating license.

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

H. The Updated Safety Analysis Report supplement, as revised, describes certain future activities to be completed prior to the period of extended operation. NMC shall complete these activities no later than September 8, 2010, and shall notify the NRC in writing when implementation of these activities is complete and can be verified by NRC inspection.

INSERT OL-2.C.13

Leak Rate Testing

2.C.13 Leak rate tests required by surveillance requirements (SR) 3.6.1.1.1, SR 3.6.1.2.1, SR 3.6.1.3.11, SR 3.6.1.3.12, and SR 3.6.1.13 are not required to be performed until their next scheduled performance. The next scheduled performance is due at the end of the first surveillance interval that begins on the date the SR was last performed prior to implementation of Amendment No.____.

1.1 Definitions

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).
RATED THERMAL POWER (RTP)	~~RTP shall be a total reactor core heat transfer rate to the reactor coolant of 1775 MWt.~~ INSERT TS 1.1-4A
REACTOR PROTECTION SYSTEM (RPS) RESPONSE TIME	The RPS RESPONSE TIME shall be that time interval from initiation of any RPS channel trip to the de-energization of the scram pilot valve solenoids. The response time may be measured by means of any series of sequential, overlapping, or total steps so that the entire response time is measured.
SHUTDOWN MARGIN (SDM)	SDM shall be the amount of reactivity by which the reactor is subcritical or would be subcritical assuming that: a. The reactor is xenon free; b. The moderator temperature is 68°F; and c. All control rods are fully inserted except for the single control rod of highest reactivity worth, which is assumed to be fully withdrawn. With control rods not capable of being fully inserted, the reactivity worth of these control rods must be accounted for in the determination of SDM.
STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.
THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.

Insert TS 1.1-4A

RTP shall be a total reactor core heat transfer rate to the reactor coolant of 2004 MWt. This power level is the basis for all safety analyses, including emergency core cooling system (ECCS) and containment performance.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1 Reduce THERMAL POWER to ≤ ~~45~~ 40% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1 Be in MODE 2. AND F.2 ----------NOTE---------- Only applicable to Function 5. ---------- Reduce reactor pressure to < 600 psig.	6 hours 12 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1 Be in MODE 3.	12 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1 Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

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

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

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

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.1.2	----------NOTE---------- Not required to be performed until 12 hours after THERMAL POWER ≥ 25% RTP. ---------- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP while operating at ≥ 25% RTP.	7 days
SR 3.3.1.1.3	----------NOTE---------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL FUNCTIONAL TEST.	7 days
SR 3.3.1.1.4	Perform a functional test of each RPS automatic scram contactor.	7 days
SR 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	31 days
SR 3.3.1.1.6	Calibrate the local power range monitors.	~~2000~~ 1770 effective full power hours
SR 3.3.1.1.7	Perform CHANNEL FUNCTIONAL TEST.	92 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.8	Calibrate the trip units.	92 days
SR 3.3.1.1.9	----------NOTE---------- Neutron detectors are excluded. ---------- Perform CHANNEL CALIBRATION.	 92 days
SR 3.3.1.1.10	Perform CHANNEL FUNCTIONAL TEST.	24 months
SR 3.3.1.1.11	----------NOTES---------- 1. Neutron detectors are excluded. 2. For Function 1, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. ---------- Perform CHANNEL CALIBRATION.	 24 months
SR 3.3.1.1.12	Perform LOGIC SYSTEM FUNCTIONAL TEST.	24 months
SR 3.3.1.1.13	Verify Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure - Low Functions are not bypassed when THERMAL POWER is > ~~45~~ 40% RTP.	24 months
SR 3.3.1.1.14	----------NOTE---------- For Function 5 "n" equals 4 channels for the purpose of determining the STAGGERED TEST BASIS Frequency. ---------- Verify the RPS RESPONSE TIME is within limits.	 24 months on a STAGGERED TEST BASIS

Table 3.3.1.1-1 (page 1 of 4)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Intermediate Range Monitors					
a. Neutron Flux - High High	2	3	G	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.11 SR 3.3.1.1.12 SR 3.3.1.1.14	≤ 122/125 divisions of full scale
	5[a]	3	H	SR 3.3.1.1.1 SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.11 SR 3.3.1.1.12 SR 3.3.1.1.14	≤ 122/125 divisions of full scale
b. Inop	2	3	G	SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.12	NA
	5[a]	3	H	SR 3.3.1.1.3 SR 3.3.1.1.4 SR 3.3.1.1.12	NA
2. Average Power Range Monitors					
a. Neutron Flux – High, (Setdown)	2	3[c]	G	SR 3.3.1.1.1 SR 3.3.1.1.4 SR 3.3.1.1.6 SR 3.3.1.1.11 SR 3.3.1.1.15	≤ 20% RTP
b. Simulated Thermal Power – High	1	3[c]	F	SR 3.3.1.1.1 SR 3.3.1.1.2 SR 3.3.1.1.4 SR 3.3.1.1.6 SR 3.3.1.1.11 SR 3.3.1.1.15	≤ ~~0.66 W + 61.6~~ 0.55W+61.5 % RTP[b] and ≤ 116% RTP

0.55(W - DeltaW) + 61.5

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

(b) ≤ ~~0.66 (W - Delta W) + 61.6~~ 0.55(W - DeltaW) + 61.5 % RTP when reset for single loop operation per LCO 3.4.1, "Recirculation Loops Operating." The cycle-specific value for Delta W is specified in the COLR.

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

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

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION D.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Scram Discharge Volume Water Level - High					
b. Float Switch	1, 2	2	G	SR 3.3.1.1.4 SR 3.3.1.1.7 SR 3.3.1.1.9 SR 3.3.1.1.12	≤ 56.0 gallons
	5[a]	2	H	SR 3.3.1.1.4 SR 3.3.1.1.7 SR 3.3.1.1.9 SR 3.3.1.1.12	≤ 56.0 gallons
8. Turbine Stop Valve - Closure	>45% RTP	4	E	SR 3.3.1.1.4 SR 3.3.1.1.7 SR 3.3.1.1.11 ~~SR 3.3.1.1.12~~ ~~SR 3.3.1.1.13~~ SR 3.3.1.1.14	≤ 10% closed 40
9. Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure - Low	>45% RTP	2	E	SR 3.3.1.1.4 SR 3.3.1.1.7 SR 3.3.1.1.9 SR 3.3.1.1.12 SR 3.3.1.1.13 SR 3.3.1.1.14	≥ 167.8 psig
10. Reactor Mode Switch - Shutdown Position	1, 2	1	G	SR 3.3.1.1.10 SR 3.3.1.1.12	NA
	5[a]	1	H	SR 3.3.1.1.10 SR 3.3.1.1.12	NA
11. Manual Scram	1, 2	1	G	SR 3.3.1.1.5 SR 3.3.1.1.12	NA
	5[a]	1	H	SR 3.3.1.1.5 SR 3.3.1.1.12	NA

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

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. HPCI System inoperable. AND Condition A, B, or C entered.	I.1 Restore HPCI System to OPERABLE status. OR I.2 Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status.	72 hours 72 hours
J. One ADS valve inoperable.	J.1 Restore ADS valve to OPERABLE status.	14 days
~~K. One ADS valve inoperable.~~ ~~AND~~ ~~Condition A, B, or C entered.~~	~~K.1 Restore ADS valve to OPERABLE status.~~ ~~OR~~ ~~K.2 Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status.~~	~~72 hours~~ ~~72 hours~~
~~L.~~ Required Action and associated Completion Time of Condition H, I, J, or ~~K~~ not met. OR Two or more ADS valves inoperable. OR HPCI System or one or more ADS valves inoperable and Condition D or F entered.	~~L.1~~ Be in MODE 3. AND ~~L.2~~ Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours

OR

K

OR

One ADS Valve inoperable and Condition A, B, C, D, or F entered.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
M Two or more low pressure ECCS injection/spray subsystems inoperable ~~for reasons other than~~ Condition C, D, or F. OR HPCI System and one or more ADS valves inoperable.	M1 Enter LCO 3.0.3.	Immediately L

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify, for each low pressure ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	31 days
SR 3.5.1.2	Verify each ECCS injection/spray subsystem manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.5.1.3	Verify ADS pneumatic pressure is as follows for each required ADS pneumatic supply: a. S/RV Accumulator Bank header pressure ≥ 88.3 psig; and b. Alternate Nitrogen System pressure is ≥ 220 psig.	31 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.1.3.6	Verify the isolation time of each MSIV is ≥ 3 seconds and ≤ 9.9 seconds.	24 months
SR 3.6.1.3.7	Verify each automatic PCIV actuates to the isolation position on an actual or simulated isolation signal.	24 months
SR 3.6.1.3.8	Verify each reactor instrumentation line EFCV actuates on a simulated instrument line break to restrict flow to ≤ 2 gpm.	24 months
SR 3.6.1.3.9	Verify each 18 inch primary containment purge and vent valve is blocked to restrict the valve from opening > 40°.	24 months
SR 3.6.1.3.10	Remove and test the explosive squib from each shear isolation valve of the TIP System.	24 months on a STAGGERED TEST BASIS
SR 3.6.1.3.11	Perform leakage rate testing for each 18 inch primary containment purge and vent valve with resilient seals.	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.3.12	Verify leakage rate through each MSIV is: (a) ≤ 100 scfh when tested at ≥ 42 psig (P_a); or (b) ≤ 77 scfh when tested at ≥ 25 psig. 75.3 44.1	In accordance with the Primary Containment Leakage Rate Testing Program
SR 3.6.1.3.13	Verify leakage rate through the main steam pathway is: (a) ≤ 200 scfh when tested at ≥ 42 psig (P_a); or (b) ≤ 154 scfh when tested at ≥ 25 psig). 150.6	In accordance with the Primary Containment Leakage Rate Testing Program

5.5 Programs and Manuals

5.5.10 Safety Function Determination Program (SFDP) (continued)

3. A required system redundant to the support system(s) for the supported systems described in Specifications 5.5.10.b.1 and 5.5.10.b.2 above is also inoperable.

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

5.5.11 Primary Containment Leakage Rate Testing Program

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

1. The Type A testing Frequency specified in NEI 94-01, Revision 0, Paragraph 9.2.3, as "at least once per 10 years based on acceptable performance history" is modified to be "at least once per 15 years based on acceptable performance history." This change applies only to the interval following the Type A test performed in March 1993;

2. The main steam line pathway leakage contribution is excluded from the sum of the leakage rates from Type B and C tests specified in Section III.B of 10 CFR 50, Appendix J, Option B, Section 6.4.4 of ANSI/ANS 56.8-1994, and Section 10.2 of NEI 94-01, Rev. 0; and

3. The main steam line pathway leakage contribution is excluded from the overall integrated leakage rate from Type A tests specified in Section III.A of 10 CFR 50, Appendix J, Option B, Section 3.2 of ANSI/ANS 56.8-1994, and Section 8.0 and 9.0 of NEI 94-01, Rev. 0.

b. The calculated peak containment internal pressure for the design basis loss of coolant accident, P_a, is 42 psig. The containment design pressure is 56 psig. 44.1

c. The maximum allowable containment leakage rate, L_a, at P_a, shall be 1.2% of containment air weight per day.

Enclosure 3 to L-MT-08-018

Proposed Technical Specifications Bases Changes Mark-up (For Information Only)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Allowable Value is chosen low enough to ensure that there is sufficient volume in the SDV to accommodate the water from a full scram. The Allowable Value refers to the volume of water in the discharge volume receiver tank and does not include the volume in the lines to the levels switches.

Four channels of each type of Scram Discharge Volume Water Level - High Function, with two channels of each type in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from these Functions on a valid signal. These Functions are required in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

8. Turbine Stop Valve - Closure

Closure of the TSVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TSV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Stop Valve - Closure Function is the primary scram signal for the turbine trip event analyzed in Reference 14. For this event, the reactor scram reduces the amount of energy required to be absorbed and ensures that the MCPR SL is not exceeded.

Turbine Stop Valve - Closure signals are initiated from position switches located on each of the four TSVs. One position switch and two independent contacts are associated with each stop valve. One of the two contacts provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Stop Valve - Closure channels, each consisting of one position switch. The logic for the Turbine Stop Valve - Closure Function is such that three or more TSVs must be closed to produce a scram. This Function must be enabled at THERMAL POWER >45% RTP. This is normally accomplished automatically by pressure switches sensing turbine first stage pressure. The pressure switches are normally adjusted lower (60% RTP) to account for the turbine bypass valves being opened, such that 14% of the THERMAL POWER is being passed directly to the condenser.

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26.6

11.6

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

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Eight channels of Turbine Stop Valve - Closure Function, with four channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function even if one TSV should fail to close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is >~~45~~% RTP. This Function is not required when THERMAL POWER is ≤~~45% RTP~~ 40 since the Reactor Vessel Steam Dome Pressure - High and the Average Power Range Monitor Flow Referenced Neutron Flux - High High Functions are adequate to maintain the necessary safety margins.

9. Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure - Low

Fast closure of the TCVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the transients that would result from the closure of these valves. The Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure - Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 15. For this event, the reactor scram reduces the amount of energy required to be absorbed and ensures that the MCPR SL is not exceeded.

Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure - Low signals are initiated by loss of oil pressure at the acceleration relay. Two pressure switches are mounted on one pressure tap while two other pressure switches are mounted at a distance on another pressure tap. The pressure switches associated with one pressure tap are assigned to different RPS trip systems. ~~This Function must be enabled at THERMAL~~ 40 POWER >~~45~~% RTP. This is normally accomplished automatically by pressure switches sensing turbine first ~~stage pressure. The pressure~~ 26.6 switches are normally adjusted lower (~~30~~% RTP) to account for the turbine bypass valves being opened, such that ~~14~~% of the THERMAL POWER is being passed directly to the condenser. 11.6

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

Four channels of Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure - Low Function with two channels in each trip system arranged in a one-out-of-two logic are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. This Function is required, consistent with the

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

analysis assumptions, whenever THERMAL POWER is > 45% RTP. This Function is not required when THERMAL POWER is ≤ 45% RTP, since the Reactor Vessel Steam Dome Pressure - High and the Average Power Range Monitor Flow Referenced Neutron Flux - High High Functions are adequate to maintain the necessary safety margins.

10. Reactor Mode Switch - Shutdown Position

The Reactor Mode Switch - Shutdown Position Function provides signals, via the two manual scram logic channels (A3 and B3), which are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

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

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

Two channels of Reactor Mode Switch - Shutdown Position Function, with one channel in each trip system, are available and required to be OPERABLE. The Reactor Mode Switch - Shutdown Position Function is required to be OPERABLE in MODES 1 and 2, and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

11. Manual Scram

The Manual Scram push button channels provide signals, via the two manual scram logic channels (A3 and B3), which are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

There is one Manual Scram push button channel for each of the two manual scram logic channels. In order to cause a scram it is necessary that both channels be actuated.

BASES

SURVEILLANCE REQUIREMENTS (continued)

extensions for RPS Functions were not affected by the difference in configuration since each automatic RPS logic channel has a test switch that is functionally the same as the manual scram switches in the generic model. As such, a functional test of each RPS automatic scram contactor using either its associated test switch or by test of any of the associated automatic RPS Functions is required to be performed once every 7 days. The Frequency of 7 days is based on the reliability analysis of Reference 16.

SR 3.3.1.1.5

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specification tests at least once per refueling interval with applicable extensions. The 31 day Frequency is based on engineering judgment, operating experience, and reliability of this instrumentation.

1770

SR 3.3.1.1.6

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 2000 effective full power hour Frequency is based on operating experience with LPRM sensitivity changes.

SR 3.3.1.1.7 and SR 3.3.1.1.10

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specification tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with

BASES

SURVEILLANCE REQUIREMENTS (continued)

1770

The Note to SR 3.3.1.1.9 and Note 1 to SR 3.3.1.1.11 state that neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in APRM neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.2) and the 2000 effective full power hours LPRM calibration against the TIPs (SR 3.3.1.1.6). Changes in IRM neutron detector sensitivity are compensated for by periodically evaluating the compensating voltage setting and making adjustments as necessary. Note 2 to SR 3.3.1.1.11 requires the IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

The Frequency of SR 3.3.1.1.9 is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.1.1.11 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.1.12

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

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.13

This SR ensures that scrams initiated from the Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure - Low Functions will not be inadvertently bypassed when THERMAL POWER is > 45% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed during in-service calibration at THERMAL POWER > 45% RTP, if performing the calibration using actual turbine first stage pressure, to ensure that the calibration is valid. The pressure switches are normally adjusted lower (30% RTP) to account for the turbine bypass valves being opened, such that 14% of the THERMAL POWER is being passed directly to the condenser.

If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at > 45% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure - Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

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

SR 3.3.1.1.14

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. RPS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements.

The RPS RESPONSE TIME acceptance criterion is 50 milliseconds.

RPS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. A Note requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV - Closure Function. This Frequency is based on the logic interrelationships

B 3.3 INSTRUMENTATION

B 3.3.2.2 Feedwater Pump and Main Turbine High Water Level Trip Instrumentation

BASES

BACKGROUND

The Feedwater Pump and Main Turbine High Water Level Trip Instrumentation is designed to detect a potential failure of the Feedwater Level Control System that causes excessive feedwater flow.

With excessive feedwater flow, the water level in the reactor vessel rises toward the high water level reference point, causing the trip of the two feedwater pumps and the main turbine.

Reactor Vessel Water Level - High signals are provided by level sensors that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level in the reactor vessel (variable leg). Four channels of Reactor Vessel Water Level - High instrumentation are provided as input to a one-out-of-two-taken-twice initiation logic that trips the two feedwater pumps and the main turbine. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre- established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a feedwater pump and main turbine trip signal to the trip logic.

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

APPLICABLE SAFETY ANALYSES

The Feedwater Pump and Main Turbine High Water Level Trip Instrumentation is assumed to be capable of providing a turbine trip in the design basis transient analysis for a feedwater controller failure, maximum demand event (Ref. 1). The high level trip indirectly initiates a reactor scram from the main turbine trip (above 45% RTP) and trips the feedwater pumps, thereby terminating the event. The reactor scram mitigates the reduction in MCPR. 40

Feedwater Pump and Main Turbine High Water Level Trip Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires four channels of the Reactor Vessel Water Level - High instrumentation to be OPERABLE to ensure that no single instrument failure will prevent the feedwater pumps and main turbine trip on a valid high level signal. Each channel must have its setpoint set within the specified Allowable Value of SR 3.3.2.2.4. The Allowable Value is set to ensure that the thermal limits are not exceeded during the event. The

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. The core is maintained in a coolable geometry; and

e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference 10. For a large discharge pipe break LOCA, failure of the LPCI valve on the unbroken recirculation loop is considered the most limiting break/failure combination. For a small break LOCA, HPCI failure is the most severe failure. One ADS valve is assumed to fail for events requiring ADS operation. The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

The ECCS satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Each ECCS injection/spray subsystem and three ADS valves are required to be OPERABLE. The ECCS injection/spray subsystems are defined as the two CS subsystems, the two LPCI subsystems, and one HPCI System. The low pressure ECCS injection/spray subsystems are defined as the two CS subsystems and the two LPCI subsystems.

With less than the required number of ECCS subsystems OPERABLE, the potential exists that during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in Reference 9 could be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by Reference 9.

As noted, LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR shutdown cooling supply isolation interlock in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. This allowance is necessary since the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

BASES

ACTIONS (continued)

K.1 and K.2

If any one low pressure ECCS injection/spray subsystem, or one LPCI pump in both LPCI subsystems, is inoperable in addition to one inoperable ADS valve, adequate core cooling is ensured by the OPERABILITY of HPCI and the remaining low pressure ECCS injection/spray subsystem. However, overall ECCS reliability is reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since both a high pressure system (ADS) and a low pressure subsystem(s) are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the low pressure ECCS subsystem(s) or the ADS valve to OPERABLE status. This Completion Time is based on a reliability study cited in Reference 11 and has been found to be acceptable through operating experience.

K

L.1 and L.2

If any Required Action and associated Completion Time of Condition H, I, J or K is not met, or if two or more ADS valves are inoperable, or if the HPCI System or one or more ADS valves are inoperable and Condition D or F entered, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

OR A

L

Insert B 3.5.1-10A

M.1

When multiple ECCS subsystems are inoperable, as stated in Condition M, the plant is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the CS System and LPCI subsystems full of water ensures that the ECCS will perform properly, injecting its full capacity into the RCS upon demand. This will

Insert B 3.5.1-10A

or one ADS valve is inoperable in combination with any other inoperable ECCS component or subsystem

BASES

APPLICABLE SAFETY ANALYSES

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

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

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

The maximum allowable leakage rate for the primary containment (L_a) is 1.2% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 42 psig (Ref. 1).

Primary containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Primary containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time the applicable leakage limits must be met.

Compliance with this LCO will ensure a primary containment configuration, including equipment hatches and manways, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analyses.

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

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, primary containment is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

BASES

APPLICABLE SAFETY ANALYSES

The DBA that postulates the maximum release of radioactive material within primary containment is a loss of coolant accident (LOCA). In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 1.2% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 42 psig (Ref. 2). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock.

44.1

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

The primary containment air lock satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

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

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

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the primary containment air lock is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.10

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

SR 3.6.1.3.11

For the 18 inch primary containment purge and vent valves with resilient seals, leakage rate testing consistent with the test requirements of 10 CFR 50, Appendix J, Option B (Ref. 8), is required to ensure OPERABILITY. The Frequency of this SR is in accordance with the Primary Containment Leakage Rate Testing Program.

SR 3.6.1.3.12

75.3

The Alternative Source Term DBA LOCA analyses are based on the specified leakage rate. Leakage through each MSIV must be ≤ 100 scfh when tested at ≥ 42 psig (P_a) or ≤ 77 scfh when tested at ≥ 25 psig (P_t). This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency of this SR is in accordance with the Primary Containment Leakage Rate Testing Program.

44.1

SR 3.6.1.3.13

150.6

The Alternative Source Term DBA LOCA analyses are based on the specified leakage rate. Leakage through the main steam pathway (i.e., the four main steam lines and the main steam line drains) must be ≤ 200 scfh when tested at ≥ 42 psig (P_a) or ≤ 154 scfh when tested at ≥ 25 psig (P_t). Compliance with the SR should be based on minimum pathway leakage rates when considering As-Found testing results, and maximum pathway leakage rates for results of As-left testing. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.8 Residual Heat Removal (RHR) Drywell Spray

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the RHR Drywell Spray System condenses any steam that may exist in the drywell thereby lowering drywell pressure and temperature. The RHR Drywell Spray mode of operation is not credited in the DBA loss of coolant accident (LOCA), however it is credited for the evaluation of steam line breaks inside the drywell. For these events, the RHR Drywell Spray System will ensure that the drywell air temperature is within the peak drywell air temperature limit of 335°F specified for the drywell temperature envelope for equipment qualification and will also ensure that the drywell wall temperature is within the design limit of 281°F. This function is provided by two redundant RHR drywell spray subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

340

Each of the two RHR drywell spray subsystems contains two pumps and one heat exchanger, which are manually initiated and independently controlled. The two subsystems perform the drywell spray function by circulating water from the suppression pool through the RHR heat exchangers and returning most of it to the associated drywell spray header. RHR service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the ultimate heat sink. Either RHR drywell spray subsystem is sufficient to condense the steam that may exist in the drywell during the postulated DBA.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict drywell temperature following various sizes of steam line breaks. The intent of the analyses is to demonstrate that the temperature reduction capacity of the RHR Drywell Spray System is adequate to maintain the primary containment conditions within design limits. The time history for primary containment temperature is calculated to demonstrate that the maximum temperature remains below the design limit.

The RHR Drywell Pool System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

In the event of a DBA, a minimum of one RHR drywell spray subsystem is required to mitigate the consequences of steam line breaks in the drywell and maintain the primary containment peak temperature below the design limits (Ref. 1). To ensure that these requirements are met, two RHR drywell spray subsystems must be OPERABLE with power from two

BASES

APPLICABLE SAFETY ANALYSES (continued)

discussed in the USAR, Section 5.2.3 (Ref. 2). This analysis explicitly assumes that the RHRSW System will provide adequate cooling support to the equipment required for safe shutdown. This analysis includes the evaluation of the long term primary containment response after a design basis LOCA.

The safety analysis for long term cooling was performed for various combinations of RHR System failures. The worst case single failure that would affect the performance of the RHRSW System is any failure that would disable one subsystem of the RHRSW System. As discussed in the USAR, Section 5.2.3 (Ref. 2), for this analysis, manual initiation of the OPERABLE RHRSW subsystem and the associated RHR System is assumed to occur 10 minutes after a DBA. The RHRSW flow assumed in the analysis is 3500 gpm with one pump operating in one loop. In this case, the maximum suppression chamber water temperature is 194.2°F, well below the design temperature of 281°F. 207.2

The RHRSW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

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

An RHRSW subsystem is considered OPERABLE when:

a. One pump is OPERABLE; and

b. An OPERABLE flow path is capable of taking suction from the intake structure and transferring the water to the RHR heat exchangers at the assumed flow rate. Additionally, the RHRSW cross tie valve (which allows the two RHRSW loops to be connected) may be opened since the cross tie valve is only 1 inch in size and the RHRSW pump flow requirements (tested per the requirements of the Inservice Testing Program) account for the flow through the open cross tie valve.

An adequate suction source is not addressed in this LCO since the minimum net positive suction head (899 ft mean sea level in the service water basin) is bounded by the emergency service water pump requirements (LCO 3.7.2, "Emergency Service Water (ESW) System and Ultimate Heat Sink (UHS)").

B 3.7 PLANT SYSTEMS

B 3.7.7 Main Turbine Bypass System

BASES

BACKGROUND	The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is 12% of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of two valves connected to the main steam lines between the main steam isolation valves and the turbine stop valve bypass valve chest. Each of the two valves is operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Electrical Pressure Regulator or the Mechanical Pressure Regulator, as discussed in the USAR, Section 7.7.2.2 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves that direct all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows from the bypass chest, through connecting piping, to the pressure reducer assemblies, where the steam pressure is reduced before the steam enters the condenser. 11.6
APPLICABLE SAFETY ANALYSES	The Main Turbine Bypass System is assumed to function during the feedwater controller failure (maximum demand) and pneumatic system degradation, turbine trip with bypass - reduced scram speeds transients, as discussed in the USAR, Sections 14.4.4 and 14A.4 (Refs. 2 and 3), respectively. Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. The Main Turbine Bypass System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, so that the Safety Limit MCPR is not exceeded. An OPERABLE Main Turbine Bypass System requires the bypass valves to open in response to increasing main steam line pressure. This response is within the assumptions of the applicable analyses (Refs. 2 and 3).