Xcel Energy

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

November 5, 2008

L-MT-08-052
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 (TAC MD9990)

References
1) March 31, 2008, "License Amendment Request: Extended Power Uprate" (TAC No. MD5531) ML081010193
2) June 25, 2008, "Monticello Nuclear Generating Plant (MNGP) – Withdrawal of Application for Extended Power Uprate Amendment" (TAC No. MD8398) ML081990446
3) June 26, 2008, "Monticello Nuclear Generating Plant (MNGP) – Withdrawal of Application for Extended Power Uprate Amendment" (TAC MD8398) ML081770338

Pursuant to 10 CFR 50.90, Northern States Power Company, a Minnesota corporation (NSPM), 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 2,004 MWt, an approximate thirteen percent increase in the current licensed thermal power (CLTP). This proposed request for Extended Power Uprate (EPU) represents an increase of approximately 20 percent above the Original Licensed Thermal Power (OLTP). This request also includes the supporting TS changes necessary to implement the increased power level.

By letter dated March 31, 2008 (Reference 1), Nuclear Management Company (now NSPM) submitted a request to increase the maximum power level of MNGP. By letter dated June 25, 2008, NMC withdrew this request (Reference 2). The enclosed submittal supersedes the original request.

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Nuclear Regulatory Commission (NRC) approval of the requested increase in reactor thermal power level would allow NSPM 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.

NSPM 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 NSPM'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 has transferred the OL to NSPM. References to NMC in the EPU LAR resubmittal are to be considered as references to NSPM. NSPM is the operating company for MNGP. MNGP is owned by Northern States Power Company, a Minnesota Corporation (NSPM) which is doing business in Minnesota as Xcel Energy. NSPM is used in this LAR where the subject applies to a function of the operating company. The "Company" is used where the subject applies to the plant owner (NSPM/Xcel Energy).

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 Report (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.

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

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 NSPM. 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.

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 the Midwest Independent System Operator 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.

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.

Enclosure 16 provides a table of docketed NRC acceptance review questions associated with the March 31, 2008 EPU LAR submittal. It also contains the response letters provided by NMC during the acceptance review process. Enclosure 16 is provided as a reference to assist the NRC in its review of NSPM's EPU LAR resubmittal request.

Enclosure 17 provides information to address the NRC's review concerns documented in Reference 3.

NSPM plans to implement the first phase of the extended power uprate following the spring 2009 refueling outage (RF024). Therefore, to support the NSPM schedule for the power ascension which would occur following the completion of RF024 EPU modifications (listed in Enclosure 8), NSPM requests that the proposed amendment be approved by December 1, 2009. Implementation of the first phase of the uprate is planned to be completed within 120 days from NRC approval of the EPU LAR. Phase two of the extended power uprate is planned for implementation following the completion of modifications scheduled for the refueling outage in 2011 (RF025). 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.

Commitment Summary

NSPM will inspect the steam dryer during the next refueling outage to confirm no unexpected changes in crack length on the steam dryer.

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

Executed on November 5, 2008.

Timothy J. O'Connor
Site Vice President
Monticello Nuclear Generating Plant
Northern States Power Company - Minnesota

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

Enclosures (17)

Enclosure 1 to L-MT-08-052

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

ENCLOSURE 1

EVALUATION OF PROPOSED CHANGES

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 2,004 megawatts thermal (MWt), which is approximately 20 percent above the original rated thermal power (RTP) of 1,670 MWt, and approximately thirteen 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 Northern States Power Company, a Minnesota corporation (NSPM) 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 of the power to flow map. 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.

As part of the MNGP EPU request, NSPM 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.

NSPM plans to implement the first phase of the extended power uprate following the spring 2009 refueling outage (RF024). Therefore, to support the NSPM schedule for the power ascension which would occur following the completion of RF024 EPU modifications (listed in Enclosure 8), NSPM requests that the proposed amendment be approved by December 1, 2009.

Implementation of the first phase of the uprate is planned to be completed within 120 days from NRC approval of the EPU LAR. Phase two of the extended power uprate is planned for implementation following the completion of modifications scheduled for the refueling outage in 2011 (RF025).

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, performed by the Midwest Independent System Operator, Incorporated (MISO) was coordinated through Xcel Energy. MISO is the regional transmission organization that controls the connected transmission facilities.

Based on the two-phase EPU implementation as described in the original EPU LAR, Xcel Energy submitted two MNGP power increase interconnection requests to 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. The results of the grid stability evaluation summarized in Enclosure 14 support the requested power increase from 1775 MWt to 2,004 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, NSPM requests that a full scope review of the EPU (to 2,004 MWt) be performed by the NRC.

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 has transferred the OL to Northern States Power Company, a Minnesota corporation (NSPM). References to NMC in the EPU LAR resubmittal are to be considered as references to NSPM. NSPM is the operating company for MNGP. MNGP is owned by Northern States Power Company, a Minnesota corporation (NSPM) which is doing business in Minnesota as Xcel Energy. NSPM is used in this LAR where the subject applies to a function of the operating company. The "Company" is used where the subject applies to the plant owner (NSPM/Xcel Energy).

ENCLOSURE 1

EVALUATION OF PROPOSED CHANGES

This EPU proposal would change the following:

Extended Power Uprate

NSPM is requesting an increase in the licensed thermal power for MNGP from 1,775 MWt to 2,004 MWt. This represents an increase of approximately thirteen 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.

NSPM 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 has been completed. The results of this evaluation are summarized as Enclosure 14. NSPM requests that a full scope review of the EPU be performed by the NRC. As part of the EPU, NSPM 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.

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 to credit 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.

ENCLOSURE 1

EVALUATION OF PROPOSED CHANGES

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 2,004 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.
1.1, Definitions	Revises the definition of RATED THERMAL POWER (RTP) from 1,775 MWt to 2,004 MWt.	For power level, see Enclosure 5, Section 1.3.1 and Table 1-2.

Table 1
Monticello Proposed
Operating License and Technical
Specification Changes

TS Section	Description of Change	Basis for Change
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.
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)

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 3.3.1.1.13	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.b	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 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 4^{th} 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 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.
SR 3.6.1.3.12	Modify acceptance surveillance requirement (b) to reduce the leakage limit from ≤ 77 scfh to 75.3 scfh. Modify acceptance surveillance requirement (b) to increase the test pressure limit from 42 P_a to 44.1 P_a.	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. $[77 = (100/\sqrt{42}) \times (\sqrt{25})]$ The revised limit is based on maintaining the same relationship based on the test pressure (25 psig) to the associated leakage limit. $[75.3 = (100/\sqrt{44.1}) \times (\sqrt{25})]$

Table 1
Monticello Proposed
Operating License and Technical
Specification Changes

TS Section	Description of Change	Basis for Change
SR 3.6.1.3.13	Modify acceptance surveillance requirement (b) to reduce the leakage limit from ≤ 154 scfh to 150.6 scfh. Modify acceptance surveillance requirement (b) to increase the test pressure limit from 42 P_a to 44.1 P_a.	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 3.2.3.1 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) 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. NSPM 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.

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 NSPM, 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 2,004 MWt. This thermal power level conservatively correlates to the electrical power cited in the interconnection request for the implementation phase of the EPU.
- 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 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.

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

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 (P_a). P_a 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, NSPM proposes to not re-perform all the leak rate tests at the higher P_a 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.

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 for containment overpressure is required for the DBA-LOCA case. The assumptions used in containment response analyses 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, available wetwell pressure and required containment pressure to satisfy the NPSH Required (NPSHR), 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 originally 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 weight 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 three percent NPSHR curves. One percent NPSHR curves are provided for information.

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 three percent NPSHR curves. One percent NPSHR curves are provided for information.

For SBA Enclosure 5, Table 2.6-9 and Figures 2.6-7 and 2.6-8 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 three percent NPSHR curves. One percent NPSHR curves are provided for information.

Based on the above, Monticello is requesting continued approval of maximum overpressure credit of 20.36 psia to 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, Northern States Power Company, a Minnesota corporation (NSPM) requests an amendment for an extended power uprate. NSPM 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. NSPM'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.

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.

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 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.

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 to cover additional events. 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.

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 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.

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.

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

Based on the considerations above, the NSPM 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.

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 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.

<u>Other Proposed Changes</u>

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

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)

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

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[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.”

Enclosure 2 to L-MT-08-052

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

2. Pursuant to the Act and 10 CFR Part 70, NSPM 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, NSPM 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, NSPM 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, NSPM 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

NSPM is authorized to operate the facility at steady state reactor core power levels not in excess of ~~4775~~ megawatts (thermal). 2004

2. Technical Specifications

The Technical Specifications contained in Appendix A, as revised through Amendment No. ~~156,~~ are hereby incorporated in the license. NS PM shall operate the facility in accordance with the Technical Specifications.

Remove space between "S" and "P"

3. Physical Protection

NSPM 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. NSPM 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. NSPM 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. NSPM 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, NSPM may make changes to the programs and activities described in the supplement without prior Commission approval, provided that NSPM 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. NSPM 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

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 3.6.1.3.13 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.~~ 2004 MWt
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.

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~~ % RTP. {40}	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
	AND		
	F.2	------------NOTE------------ Only applicable to Function 5. ------------------------------------- Reduce reactor pressure to < 600 psig.	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% RTP[(b)] and ≤ 116% RTP 0.55W+61.5

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% 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~~ 40% 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
9. Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure - Low	> ~~45~~ 40% 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 OR I.2	Restore HPCI System to OPERABLE status. 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~~ ~~OR~~ ~~K.2~~	~~Restore ADS valve to OPERABLE status.~~ ~~Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status.~~	~~72 hours~~ ~~72 hours~~
~~L.~~ [K] Required Action and associated Completion Time of Condition H, I, [or] 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. [OR One ADS valve inoperable and Condition A, B, C, D, or F entered.]	~~L~~[K].1 AND ~~L~~[K].2	Be in MODE 3. Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
~~H~~. 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.	~~H~~.1 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 ≥ 410 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~~ 44.1 psig (P_a); or (b) ≤ ~~77~~ 75.3 scfh when tested at ≥ 25 psig.	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~~ 44.1 psig (P_a); or (b) ≤ ~~154~~ 150.6 scfh when tested at ≥ 25 psig).	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 exceptions:

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~~ 44.1 psig. The containment design pressure is 56 psig.

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-08-052
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 (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.

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 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 POWER > 45% RTP. This is normally accomplished automatically by pressure switches sensing turbine first stage pressure. 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.

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.

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)

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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)

This LCO helps to ensure that the following acceptance criteria for the ECCS (Ref. 8), established by 10 CFR 50.46 (Ref. 9), will be met following a LOCA, assuming the worst case single active component failure in the ECCS:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

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

BASES

ACTIONS (continued)

reliability study cited in Reference 11 and has been found to be acceptable through operating experience.

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.

L.1 and L.2 K

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.

INSERT B3.5.1-10A

M.1 L

When multiple ECCS subsystems are inoperable, as stated in Condition M, the plant is in a degraded condition not specifically justified for continued operation, and may be in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

For many cases, including the one where two or more low pressure ECCS injection/spray subsystems in the same Division (one LPCI subsystem and one core spray subsystem) are inoperable, per the single

Insert B 3.5.1-10A

or one ADS valve is inoperable in combination with Condition A, B, C, D or F entered.

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 ≤ 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

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 ≥ 44.1 psig (P_a) or ≤ 75.3 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.

SR 3.6.1.3.13

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 ≥ 44.1 psig (P_a) or ≤ 150.6 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
340 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.

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. 11.6 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.

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).

Enclosure 4 to L-MT-08-052

MNGP Extended Power Uprate
Environmental Assessment

ENCLOSURE 4

MNGP EXTENDED POWER UPRATE ENVIRONMENTAL ASSESSMENT

NOVEMBER 2008

NORTHERN STATES POWER COMPANY, A MINNESOTA CORPORATION (NSPM)

MONTICELLO NUCLEAR GENERATING PLANT

MONTICELLO, MINNESOTA

RENEWED LICENSE NO. DPR-22

DOCKET NO. 50-263

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EXECUTIVE SUMMARY

This document presents an evaluation of the environmental impacts of the proposed Monticello extended power uprate from 1775 MWth to 2004 MWth. The intent of this document is to provide sufficient information for the NRC Staff to evaluate the environmental impacts of extended power uprate in accordance with the requirements of 10 CFR Part 51.

The environmental impacts of extended power uprate are identified and compared against the environmental impacts associated with the present power level which have been previously evaluated by the NRC Staff in the 1998 Monticello Nuclear Generating Plant (MNGP) Power Rerate Environmental Evaluation (Ref's. 17 and 18) as part of the MNGP Power Rerate Project and associated license amendment (Amendment 102) as well as the MNGP Operating License Renewal Environmental Evaluation, NUREG-1437 Supplement 26 (Ref's. 19 and 20). The original licensed power level environmental impacts have been previously evaluated by the NRC Staff in the Final Environmental Statement (Ref. 2) associated with the issuance of the Monticello full term operating license.

The environmental impacts identified by the NRC Staff in the Final Environmental Statement are based on conservative assumptions for source terms and other environmental parameters. Since initial operation, a variety of systematic environmental improvements have been implemented at Monticello that have further increased the margin of conservatism associated with these assumptions. By adjusting actual plant operating parameters for extended power uprate effects, it can be demonstrated that the previous assumptions and conclusions concerning the environmental impact of Monticello operation at present power levels continue to bound plant operation at extended power uprate conditions with significant margin.

In a few cases, the Final Environmental Statement and its associated documentation does not contain sufficient information necessary for a detailed comparison of the extended power uprate environmental impacts with previously evaluated impacts. In these instances, comparisons and conclusions are made using other appropriate environmental criteria established by the NRC. Where other environmental authorities govern Monticello operation such as in the matter of state water appropriation limits, comparisons and conclusions are made using the appropriate environmental permits and regulations.

The Monticello extended power uprate is being implemented without consequential changes to the plant systems that directly or indirectly interface with the environment. No environmental permits are adversely affected by extended power uprate. This evaluation demonstrates that the environmental impacts of extended power uprate are either well bounded or encompassed by previously evaluated criteria established by the NRC Staff in the FES, Rerate Environmental Evaluation and License Renewal Environmental Evaluation, NUREG-1437 Supplement 26, or well bounded by other appropriate regulatory criteria.

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1.0 INTRODUCTION

The Northern States Power Company, a Minnesota corporation (NSPM) is committed to operating the Monticello Nuclear Generating Plant (MNGP) in an environmentally sound manner. All plant activities, including design, construction, maintenance, and operation, are conducted in a manner that involves strict compliance with environmental regulations and deliberate consideration of environmental practices and consequences. Numerous controls and modifications have been implemented to prevent and reduce impacts to the environment, and extensive environmental monitoring programs have been instituted at MNGP. In keeping with this important obligation and in accordance with regulatory requirements, NSPM has conducted a comprehensive environmental evaluation of the proposed MNGP extended power uprate from 1775 MWth to 2004 MWth.

This environmental evaluation is provided pursuant to 10 CFR 51.41 and is intended to fully support the Commission in complying with the requirements of Section 102(2) of the National Environmental Policy Act (NEPA), as amended, for the proposed change to the MNGP operating power level. The scope of the evaluation is limited to that information necessary and sufficient to determine the environmental impact of those particular changes associated with the proposed extended power uprate at MNGP from 1775 MWth to 2004 MWth. This evaluation is not specifically intended to reestablish the current environmental licensing basis or to justify the environmental impacts of operating at the present power level.

The environmental impact of operation at the current licensed power level has been reviewed and determined to be acceptable by the NRC Staff. In 1971-1972, the Company provided an Environmental Report (Ref.1 & 3) to the Atomic Energy Commission (AEC) as part of NSP's application for a full term operating license. The Environmental Report addressed the environmental impacts of construction and operation of MNGP. The report was utilized by the AEC in preparing a Final Environmental Statement or FES (Ref. 2) in fulfillment of the requirements of the National Environmental Policy Act of 1969. The NRC subsequently issued a full term operating license to MNGP (Ref. 12). This license authorized a maximum power level of 1670 MWth. By the Notice of Issuance included as Enclosure 2 to Ref. 12, the Commission stated that "...issuance of this license will not result in any environmental impacts other than those evaluated in the Final Environmental Statement since the activity authorized by the license is encompassed by the overall action evaluated in the Final Environmental Statement." In September 1998, the Commission approved an increase in the maximum power level of MNGP from 1670 MWth to 1775 MWth (Ref. 18). This approval was supported by an "Environmental Assessment and Final Finding of No Significant Impact" that was transmitted to NSP in August 1998 (Ref. 17). The MNGP Facility Operating License was renewed in November 2006. This renewed operating license was supported by an Environmental Impact Statement, NUREG-1437 Supplement 26, prepared for MNGP (Ref. 19).

This evaluation demonstrates that the environmental impacts of extended power uprate are either well bounded or encompassed by previously evaluated criteria established by the NRC Staff in the FES, Rerate Evaluation and License Renewal Evaluation or well bounded by other appropriate regulatory criteria.

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2.0 OVERVIEW OF OPERATIONAL AND EQUIPMENT CHANGES

Monticello is a Boiling Water Reactor (BWR) that operates in a direct thermodynamic cycle between the reactor and the turbine. At extended power uprate conditions, thermodynamic processes are changed to extract additional work from the turbine. Simply put, extended power uprate involves an increase in the heat output of the reactor to support increased turbine inlet steam flow requirements and an increase in the heat dissipated by the condenser to support increased turbine exhaust steam flow requirements. In order to support an extended power uprate to 2004 MWth, the reactor core operating range will be expanded by increasing reactor power within existing rod and core flow control lines. No changes in operating pressure are necessary to support extended power uprate. In the turbine portion of the heat cycle, increases in steam flow will result in a slight increase in the heat rejected to the Mississippi River. The environmental impacts of these operational changes are discussed herein.

Several plant modifications are required to support operation at the extended power uprate power level. Enclosure 8 to this license amendment request contains a listing and brief description of the planned modifications. In summary, modifications are required to some systems to generate and/or accommodate the increased feedwater and steam flow rates to achieve EPU power levels. These modifications are planned to be installed over the course of two operating cycles and refueling outages to support the EPU project schedule in 2009 and 2011. There are other modifications planned for installation in the 2009 and 2011 outages. However, these other modifications are not specifically required to support EPU and many are planned to address life cycle management improvements. Additionally, the operating conditions and performance of the steam dryer will be closely monitored to determine if a modification or replacement will be necessary to support the extended power uprate.

3.0 PROPOSED ACTION AND NEED

3.1 Proposed Action

With the operational goal of increasing electrical generating capacity, NSPM, in conjunction with the plant designer, General Electric, has comprehensively evaluated the effects of an extended power uprate at Monticello. This evaluation concluded that sufficient safety and design margins exist such that a prudent increase in the rated core thermal power from 1775 to 2004 MWth can be accomplished without any adverse impact on the health and safety of the public and without any significant impact on the environment. Accordingly, NSPM is proposing an amendment to the MNGP Operating License to allow for an increase in the rated core thermal power level to 2004 MWth.

NSPM does intend to raise power in increments at MNGP. The power level following the refueling outage in 2009 will be approximately 15 MWe higher. The maximum rated thermal power level of 2004 MWth will be implemented following startup from the refueling outage in 2011. The maximum power level proposed by this action and evaluated for environmental impact herein is 2004 MWth.

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3.2 Need for Proposed Action

The Company filed a fifteen-year resource plan for the period 2008-2022 with the State of Minnesota (Ref. 21). This Resource Plan includes a forecasted average annual increase in expected customer peak demand of 1.2 percent through the 2008-2022 planning period. To meet this projected demand, generating capacity must have a net increase of 598 MWe to 11,314 MWe by 2012[1].

This Resource Plan forecast is first produced with a 50 percent probability that the energy or demand will be less than the forecast and a 50 percent probability it could be higher. These forecasts are referred to as the median forecasts. From these forecasts, the 90/10 probability forecasts are developed for both energy and demand. The forecasts include the impacts of past and future demand-side management ("DSM") programs[2]. These forecasts include a "business as usual" assumption in which there is no basic change in the relationship between the regional and national economies. The Company plans to the 50 percent energy forecast and the 90 percent demand forecast. The 90 percent forecast is used for capacity planning due to the significant financial penalties associated with not maintaining the 15 percent Mid-Continent Area Power Pool ("MAPP") reserve sharing requirement and the increasingly tight market for short-term purchases seen in recent years.

The Company has determined the need for additional generation resources through a comparison of the projected resource needs (Obligations) to the resources available to the Company (Committed Resources). The Company's resource obligations include forecasted summer peak net demand, MAPP minimum reserve requirements, and other contracted obligations. Committed resources include existing capacity, committed capacity additions, and committed capacity purchases. The results of this comparison are shown in Table 3.2-1 below.

Table 3.2-1
Company Total Resource Needs (MWe)

	2008	2012	2016	2020
Net Forecasted Obligations	10,716	11,314	11,892	12,465
Committed Resources	10,818	11,086	10,113	10,103

Included in Table 3.2-1 above is 2,400 MW of wind capacity that will be added between 2010 and 2022 to comply with the 2007 Renewable Energy Standard legislation requiring the Company to provide 25 percent of its retail sales through wind resource by 2025[3]. The proposed increase in electrical generating capacity due to the Monticello extended power uprate is not included in the Committed Resource values displayed above. As shown in Table 3.2-1, the Company expects to require increasing additional capacity through 2020. The effects of existing and new DSM programs necessary to assume a 1.1 percent reduction in retail sales has already been factored into the energy

[1] Net peak forecast after load management programs and including a 15 percent reserve margin as required by MAPP.
[2] DSM savings of 1.1 percent assumed to comply with 2007 Next Generation Act.
[3] The committed resources assumes Prairie Island Units 1 and 2 are both relicensed to operate an additional 20 years past their current licenses which expire in 2013 and 2014.

and demand forecasts. Additionally, the net forecasted demand obligations have already been reduced by the expected peak savings due to load management programs.

4.0 SOCIOECONOMIC EFFECTS

This section addresses the effect of extended power uprate on the social and economic conditions of communities affected by MNGP operation. The Company, as a matter of policy, factors in environmental costs in determining its selection of generation resources, but does not quantify socioeconomic effects of new generation. Therefore, the following discussions include the environmental costs as found in Table 4.0-1.

Table 4.0-1
Environmental Cost Values

Effluent	
SO2	$776.54/ton based on the current cost of permits under title IV of the Clean Air Act. This value increases significantly in 2010 with the implementation of the Clean Air Interstate Rule (CAIR)
NOx	$591.54/ton based on the current cost of permits under title IV of the Clean Air Act. This value increases significantly in 2009 with the implementation of the Clean Air Interstate Rule (CAIR)
Mercury	$18,432/ton starting in 2010 with the implementation of the Clean Air Mercury Rule (CAMR)
CO2	$20/ton starting in 2010. This value is meant to be an estimate of the costs from future carbon regulation.
PM10	$7,094-$923/ton depending on location, based on externality values established by the Minnesota Public Utilities Commission.
CO	$2.17-$0.40/ton depending on location, based on externality values established by the Minnesota Public Utilities Commission.
Pb	$2.17-$0.40/ton depending on location, based on externality values established by the Minnesota Public Utilities Commission.

The Company (including the employees of NSPM) is a major employer in the community (second behind the school district) and the largest single contributor, by far, to the local tax base. MNGP personnel have higher incomes than the area on average and contribute significantly to the local tax base by payment of sales taxes and property taxes. Many MNGP personnel are actively involved in volunteer work within the local community and contribute to local service agencies. All these activities have a positive impact on the local and regional economies.

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4.1 Economic Structure

Extended power uprate does not significantly affect the size of the MNGP work force and does not have a material effect on the labor force required for future plant outages.

In 2007, the Company (including the employees of NSPM) employed approximately 327 full-time workers at MNGP. These workers have a disproportionate influence on the economics of the region because of higher than average incomes. Estimated per capita and median household income in 1999 for Monticello, St. Cloud, Sherburne County, and Wright County are presented in Table 4.1-1. (The 2000 Census is the most recent demographic information available that covers all categories in Table 4.1-1 below.) The 1999 estimated average annual wage of MNGP employees was $56,720. The 2006 estimated average annual salary was $64,200.

Table 4.1-1
2000 Census Per Capita Personal and Median Household Income

Jurisdiction	Per Capita Personal Income	Median Household Income
Communities		
Monticello	$19,229	$45,384
St. Cloud	$19,769	$37,346
Counties		
Sherburne	$21,322	$57,014
Wright	$21,844	$53,945
Two-County Average	$21,583	$55,480 (rounded)
Minnesota	$23,198	$47,111

Source = http://facfinder.census.gov

4.2 Economic Benefits of Extended Power Uprate Equipment on Service Suppliers

Although the amount of plant modification and new equipment required to implement the extended power uprate is relatively small[1], there is a significant positive economic benefit to local and national businesses derived from extended power uprate at MNGP. There is a direct impact on the economy due to contracts awarded for project implementation. General Electric – Hitachi (GEH) was awarded the contract for the major engineering services associated with extended power uprate. Other local engineering firms, equipment suppliers, and service industries are receiving payments for extended power uprate related activities. This direct impact of these revenues from the Company will eventually cease

[1] The reactor system will require few modifications, but a number of balance-of-plant improvements and a new steam turbine will be necessary to take advantage of the increased steam flow.

within a few years of extended power uprate implementation. Successful implementation of extended power uprate at MNGP could result in additional follow-on revenue for equipment and service suppliers as other nuclear plant owners similarly decide to implement extended power uprate projects.

4.3 Tax Benefits of Extended Power Uprate

It is expected that the extended power uprate project will contribute approximately $1.2 million annually in property taxes above that associated with the continued operation of the plant without the extended power uprate project. The uprate will result in a payment of over $4.5 million in sales taxes. In addition, the extended power uprate project will result in an increase in state and federal income taxes being paid by workers during the implementation. Moreover, the Company will pay an estimated $30.5 million in additional state and federal income taxes over the project life.

The ability of the local community to provide public services at a reasonable tax rate is largely due to Company payments to local taxing jurisdictions. Public services, including law enforcement, fire protection, public education, and health services, receive a substantial amount of economic support through tax revenues generated by MNGP. The Company paid a total of $5,610,014 in local taxes to the City of Monticello, Wright County, School District 882, and Monticello/Big Lake Community Hospital in 2007. A significant reduction in the Company contribution from MNGP operations will result in economic penalties and/or loss of services to businesses, farmers, and homeowners as the Company tax contribution differential is apportioned to the remaining tax revenue sources.

Market values and tax disbursements for 1995, 2000, 2005, and 2007 can be found in Table 4.3-1 and Table 4.3-2 below.

Table 4.3-1
Assessed Market Values of MNGP

	1995	2000	2005	2007
Assessed Value	$262,339,700	$260,934,300	$232,574,300	$244,145,500

Table 4.3-2
Company Tax Disbursements

Taxing Jurisdiction	Taxes Paid			
	1995	2000	2005	2007
State	0	0	$567,703	$607,788
City	$2,203,800	$3,166,500	$2,727,683	$2,072,853
County	$3,718,600	$2,834,800	$1,600,493	$1,499,495
School District	$7,416,900	$5,425,700	$1,353,213	$1,285,806
Hospital	$311,700	$201,300	$124,034	$144,072
Total	$13,651,000	$11,628,300	$6,373,126	$5,610,014

4.4 Economic Competitiveness of MNGP Under Extended Power Uprate Conditions

The socioeconomic effects of extended power uprate are, in part, dependent on whether extended power uprate is economically competitive. Although implementation of extended power uprate is not the sole factor affecting the future economic competitiveness of MNGP, it is a real and material factor. While MNGP is not the least cost provider among the Company's generation assets, it is a low cost provider as compared to other base load generation. Additionally, the base load operation of a non-carbon emitting plant provides a significant hedge against future carbon regulation due to the increasing concern over the effect of carbon emissions has on global warming. The economic impact of that potential carbon hedge is estimated to be a savings of between $158 million and $295 million over the life of the plant - based on a hypothetical carbon tax of between $9/ton and $40/ton.

4.5 Environmental Justice Information

Minority and Low Income Populations

In the environmental justice analyses for previous license renewal applications, NRC used a 50-mile plant radius as the overall area that could contain environmental impact sites, and the state as the geographic area for comparative analysis. NSPM adopts a similar approach in order to identify and analyze the minority and low-income populations that could be affected by operation at extended power uprate conditions at MNGP. The following information is taken from the recent MNGP Operating License Renewal Environmental Report (Ref. 27).

Minority Populations

Minority populations were identified using the Year 2000 Census demographic data to the block group level for the following racial minority categories: Black or African American, American Indian or Alaskan Native, Asian, Native Hawaiian or Other Pacific Islander, Other Single Race, and Two or More Races. The Hispanic or Latino origin ethnicity designation is also identified. In addition to these groups, the minority population as a whole (an aggregate minority category) was included in the analysis, in accordance with NRC guidance. The aggregate minority category included data from the following minority categories: Black or African American, American Indian or Alaskan Native, Asian, Native Hawaiian or Other Pacific Islander, Other Single Race, and Two or More Races. The minority population determination for the MNGP environmental justice analysis included an evaluation of the seven minority categories used in the census and the aggregate minority population as indicated by NRC. NRC guidance specifies that a minority population exists in either of the following cases:

Exceeds 50 Percent – the minority population of the environmental impact site exceeds 50 percent or

More than 20 Percentage Points Greater – the minority population percentage of the impact site is significantly greater (typically at least 20 percentage points) than the minority population percentage in the geographic area chosen for comparative analysis.

The area within a 50-mile radius of MNGP was used in this analysis to define the area of potential environmental impact. Census block groups with greater than 50 percent of their area located outside the 50-mile radius, as defined above, were excluded from this area. The 50-mile radius of MNGP is located entirely within the State of Minnesota, and encompasses all or part of 21 counties (see Figure 4.5-1). The geographic area chosen for comparative analysis consisted of the State of Minnesota. The population demographic data from the State comprises average numbers for both the minority population as a whole and each minority category for comparison (see Table 4.5-2). The percentage of each minority group in an individual census block group was calculated as a percentage using the following:

$$[(\text{minority group population})_{\text{block group}} / \text{total population}] * 100$$

To calculate the aggregate minority population in an individual census block group, the populations of each of the six minority groups (Black or African American, American Indian or Alaskan Native, Asian, Native Hawaiian or Other Pacific Islander, Other Single Race, and Two or More Races) and the Hispanic ethnicity designation were added together and used in the above equation. Since Hispanics may be of any race, and therefore, are included within the other racial categories, the number of persons identified as white Hispanics was included in the calculation of the aggregate minority population.

Census 2000 data for the block group level from Minnesota was analyzed to determine which block groups meet either or both of the above criteria (exceed 50 percent or more than 20 percentage points greater). The 50-mile radius includes 2,166 census block groups. Table 4.5-2 shows the number of census blocks groups in each county with a minority population, and the threshold values for determining if a minority population exists. No block groups exhibit minority populations greater than 50 percent. Therefore the applicable threshold values were calculated using the "greater than 20 percent points" criterion.

There were no census block groups with a minority population of Native Hawaiian or other Pacific Islander within the 50-mile radius of MNGP. There were 325 census block groups with an aggregate minority population (see Figure 4.5-1).

For the individual minority categories:

- 149 census block groups had a minority population of Black or African Americans (see Figure 4.5-2 and Table 4.5-2),
- 3 census block groups had a minority population of American Indian or Native Alaskan (see Figure 4.5-3 and Table 4.5-2),
- 46 census block groups had a minority population of Asians (see Figure 4.5-4 and Table 4.5-2),
- 11 census block groups had a minority population of "other" single race (see Figure 4.5-5 and Table 4.5-2),
- 1 census block group had a minority population of two or more races (see Figure 4.5-6 and Table 4.5-2), and
- 52 census block groups had a minority population of Hispanics or Latino origin (see Figure 4.5-7 and Table 4.5-2).

Hennepin County, Minnesota has 123 block groups with a Black or African American minority population, Ramsey County has 25, and Carver County had one block group (see Table 4.5-2). Hennepin County is the only county within the 50-mile radius of MNGP to have block groups with an American Indian or Native Alaskan minority population (three block groups). Hennepin and Ramsey counties had block groups with Asian minority populations and were the only two counties within the 50-mile radius with an Asian minority.

The majority of the block groups with minority populations (581 of 587) were located in Hennepin and Ramsey counties, part of the Minneapolis-St. Paul metropolitan area. In conclusion, the minority populations in the 50-mile radius of MNGP are concentrated near an urban center with a high population density approximately 30 or more miles from the plant.

Low-Income Populations

As for the minority group analysis above, information about the percentage of low-income households within the 50-mile radius of MNGP was compiled using Census 2000 data to the block group level. NRC guidance specifies that a low-income population exists in either of the following cases:

<u>Exceeds 50 Percent</u> – the percentage of households below the poverty level in the census block group or environmental impact site exceeds 50 percent or

<u>More than 20 Percentage Points Greater</u> – the percentage of households below the poverty level in the census block group or environmental impact site is significantly greater (typically at least 20 percentage points) than the percentage of households below the poverty level in the geographic area chosen for comparative analysis.

The environmental impact area and geographic area for comparative analysis used to identify low-income populations are identical to those described above for identifying minority populations (i.e., all block groups extending 50 percent or more within the 50-mile radius and counties with at least one block group extending within the 50-mile radius, respectively). The percentage of households below poverty level in the State of Minnesota comprised average regional number for comparison (see Table 4.5-2). Data for both the total number of households and the number of households with an income below the poverty level was obtained for each census block group within the 50-mile radius of MNGP. The number of households below poverty in each census block group was then calculated as a percentage using the following:

$$[(\text{households below poverty})_{\text{block group}} / \text{total households}] * 100$$

Any census block group with a percentage of households below the poverty level greater than 27.9 percent (see Table 4.5-2) was considered a low-income population in this assessment.

A total of 91 census block groups within the 50-mile radius of MNGP meet the criteria for low-income populations (see Table 4.5-2). The majority of the census block groups with a low-income population were located in Hennepin County (61 block groups) and Ramsey County (23 block groups) 35 miles or more from the plant. The two other counties with census block groups that have low-income populations are Sherburne and Stearns counties (1 and 6 census blocks, respectively; see Table 4.5-2). The NRC reviewed similar Environmental Justice information for the MNGP License Renewal (Ref. 19) and concluded for that licensing action that the offsite impacts to minority and low-income populations were small and no mitigation actions were warranted.

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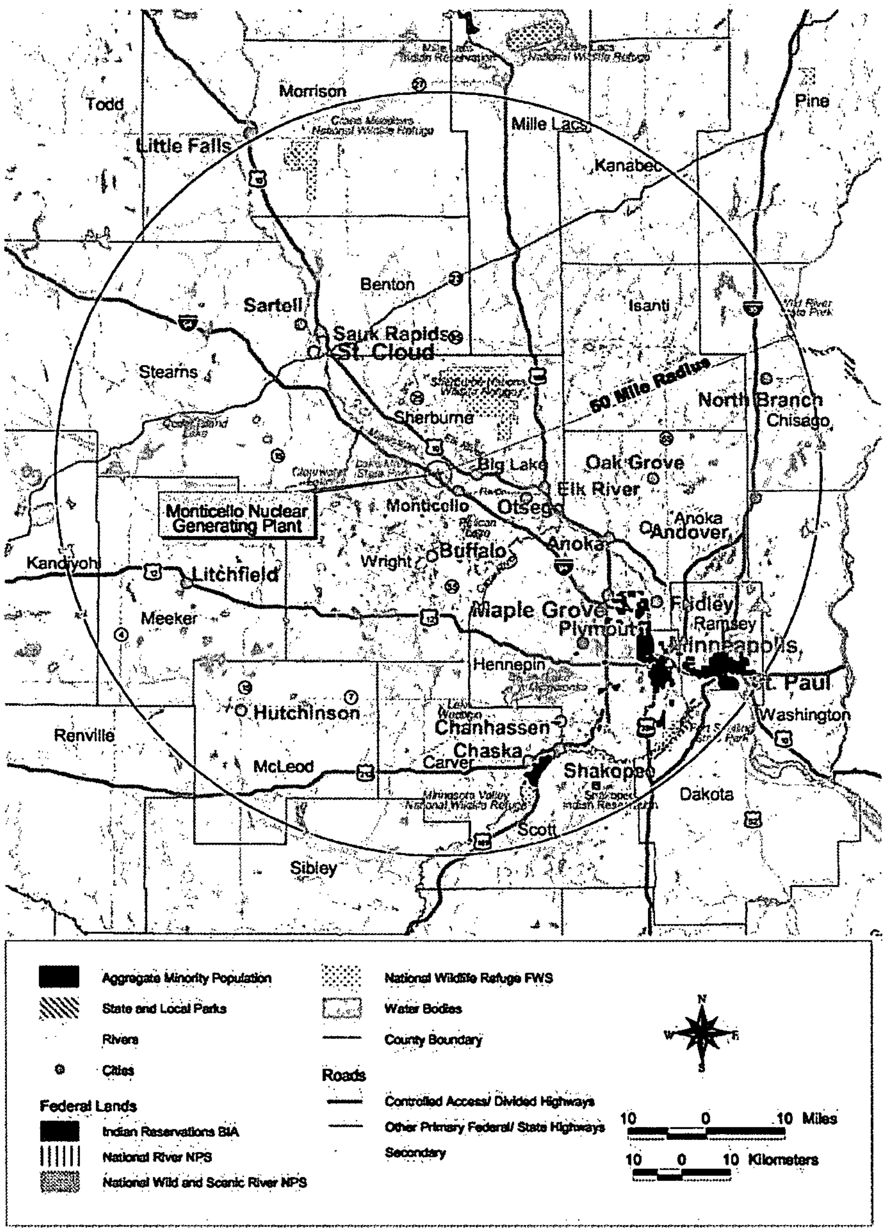
FIGURE 4.5-1

AGGREGATE MINORITY POPULATION



ENCLOSURE 4

FIGURE 4.5-2

BLACK OR AFRICAN AMERICAN MINORITY POPULATION

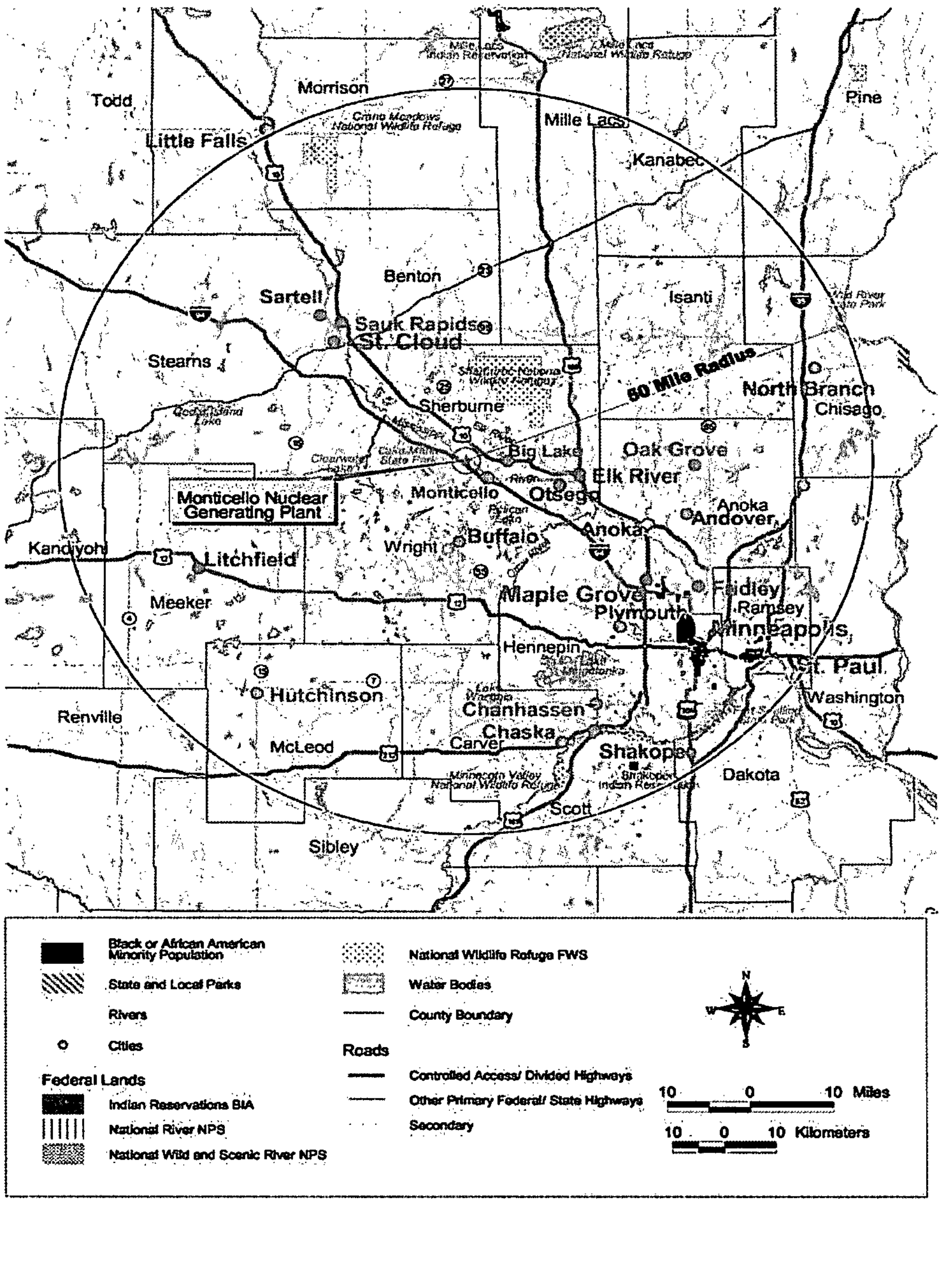


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FIGURE 4.5-3

NATIVE AMERICAN MINORITY POPULATION

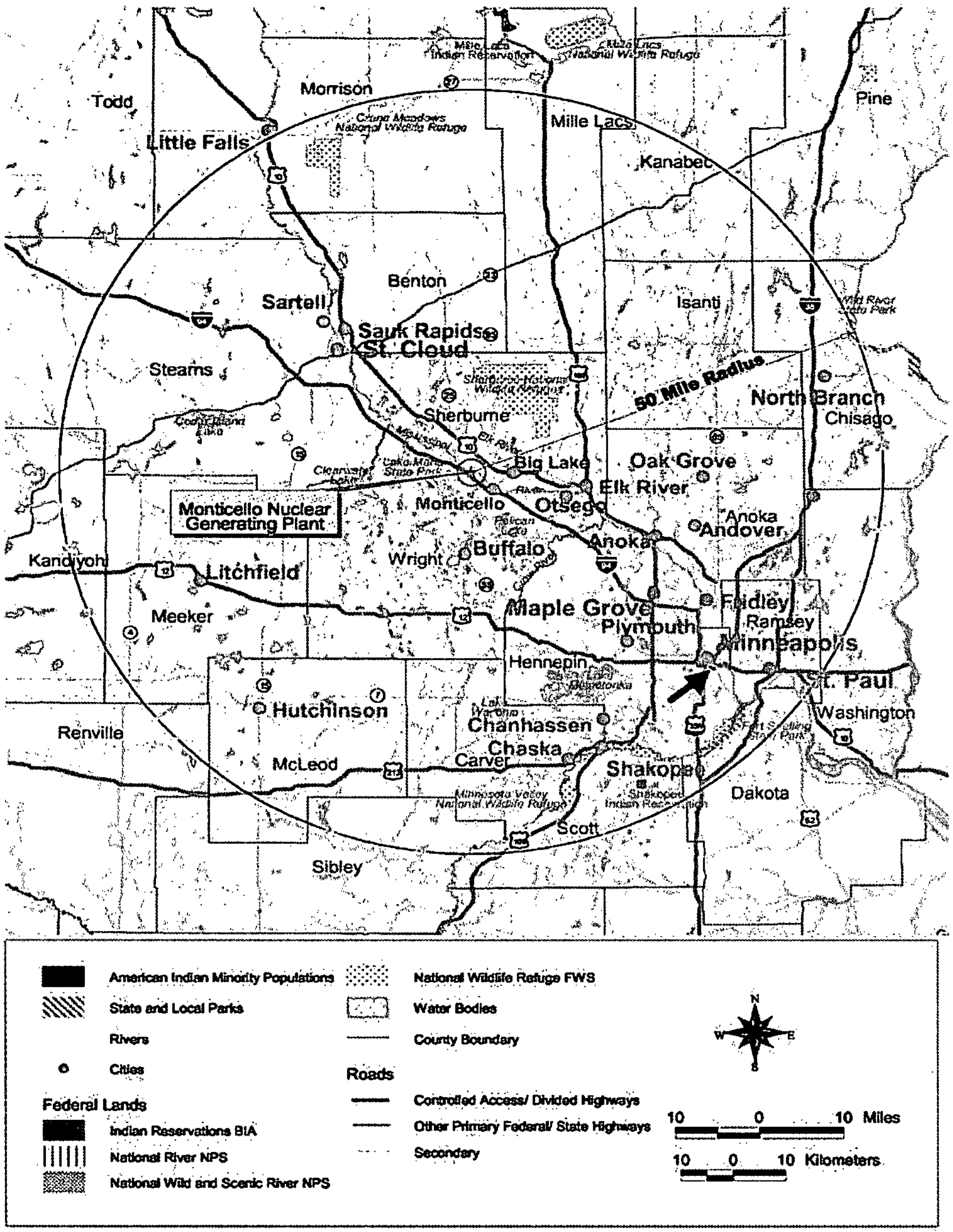

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FIGURE 4.5-4

ASIAN MINORITY POPULATION

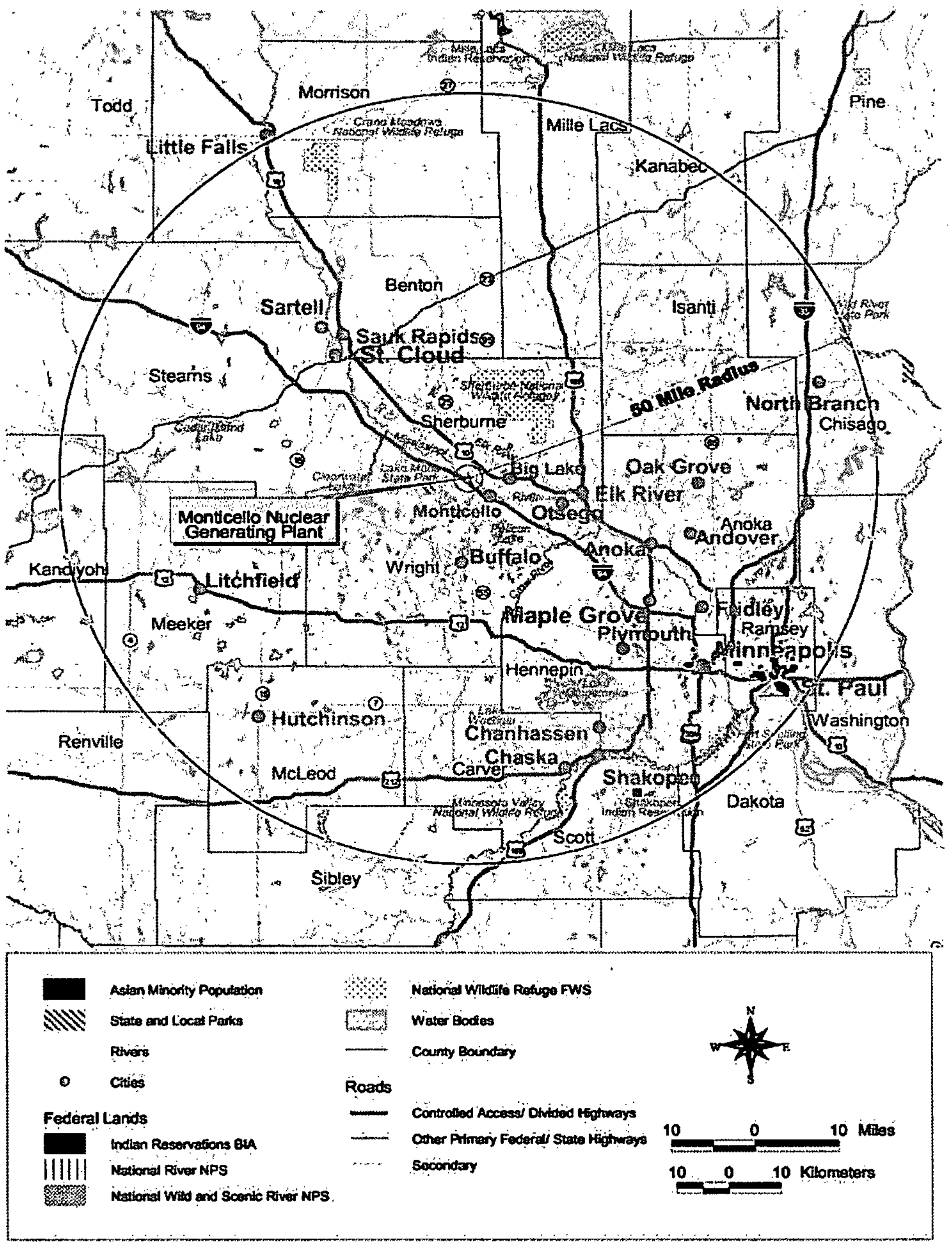

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FIGURE 4.5-5

OTHER SINGLE RACE MINORITY POPULATION

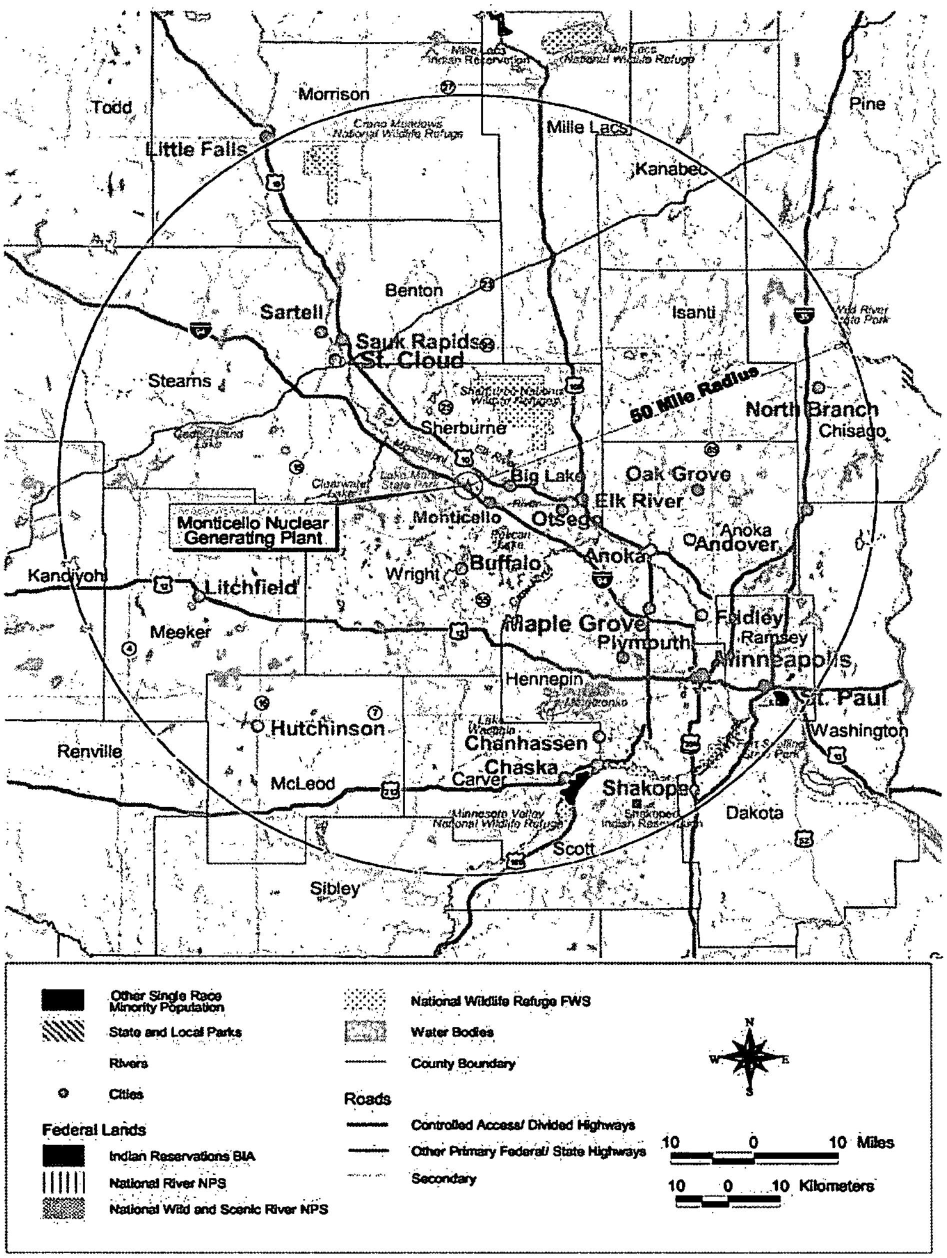

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FIGURE 4.5-6

MINORITY POPULATIONS OF TWO OR MORE RACES

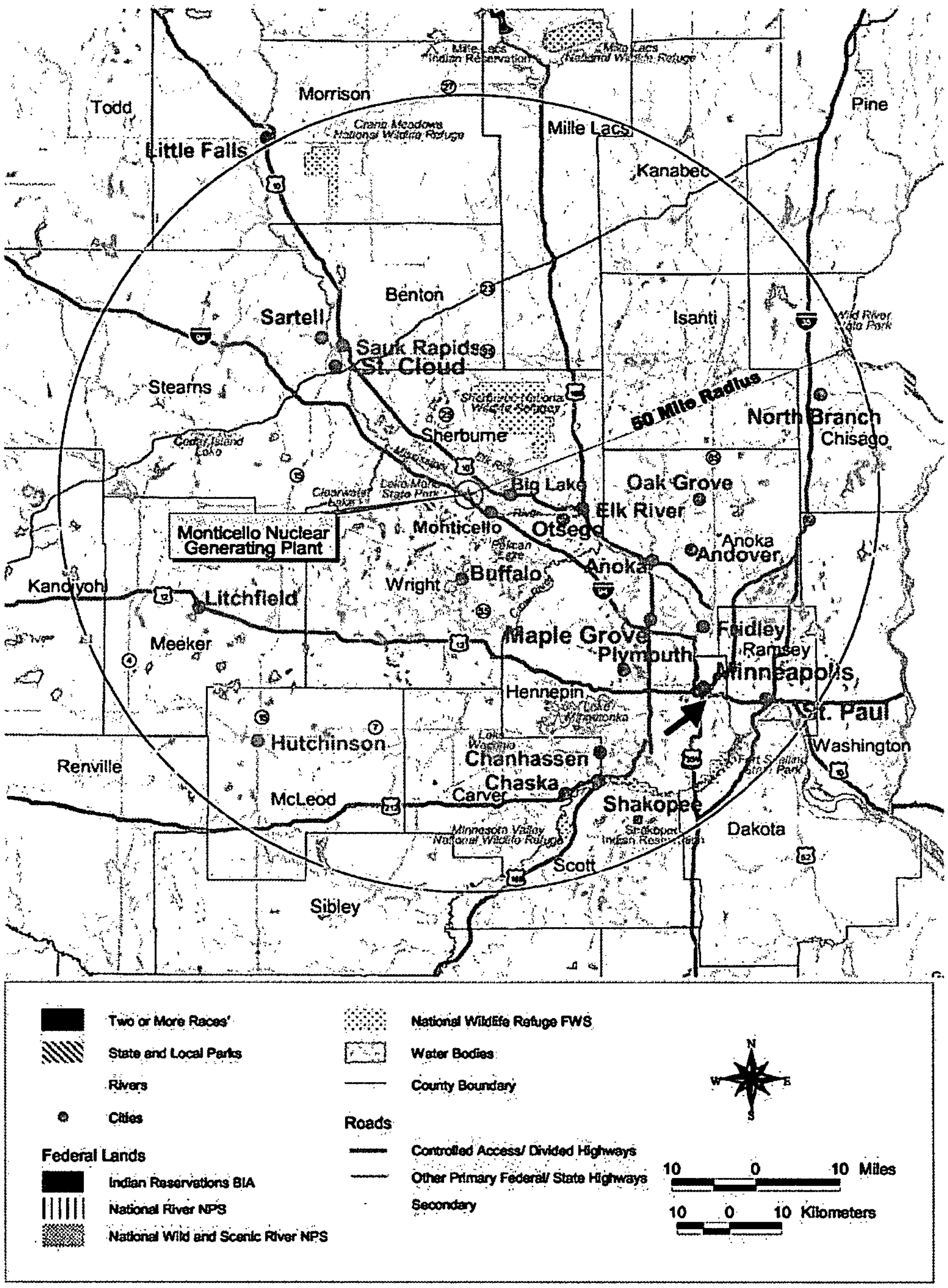

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FIGURE 4.5-7

HISPANIC OR LATINO POPULATION

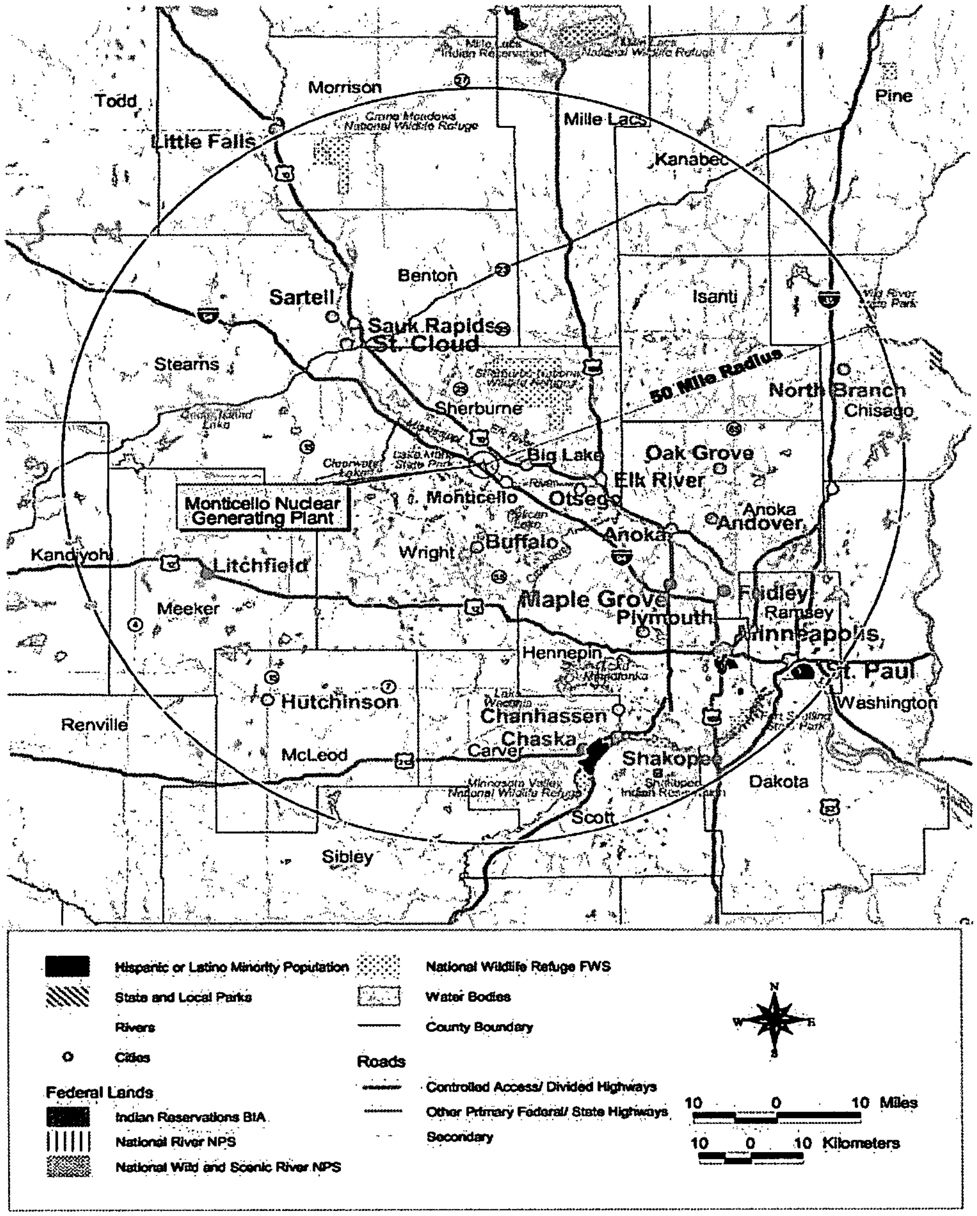

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TABLE 4.5-1
ESTIMATED POPULATIONS AND ANNUAL GROWTH RATES IN WRIGHT AND SHERBURNE COUNTIES FROM 1970 TO 2040

	Wright		Sherburne	
Year	Population[a]	Percent[b]	Population[a]	Percent[b]
1970	38,933	--	18,344	--
1980	58,681	4.19	29,908	5.01
1990	68,710	1.59	41,945	3.44
2000	89,986	2.73	64,417	4.38
2010	109,700	2.00	86,320	2.97
2020	126,420	1.43	105,620	2.04
2030	139,020	0.95	121,920	1.45
2040	152,876	0.95	140,736	1.45

a. Source: Reference 27

b. Annual percent growth rate calculated using the equation N[t] = N[o] (1+r)t where N is population, t is time in years, and r is the annual growth rate expressed as a decimal.

TABLE 4.5-2
NUMBER OF CENSUS BLOCKS WITH MINORITY AND LOW-INCOME POPULATIONS WITHIN THE 50-MILE RADIUS OF MNGP

State	County	Black or African American	American Indian and Alaska Native	Asian	Native Hawaiian and Other Pacific Islander	Other Single Minority	Two or More Races	Hispanic	Aggregate Minority	Low Income
	Regional Percent[a]	3.5	1.10	2.90	0.04	1.30	1.70	2.90	11.8	7.9
	Threshold for Minority Population[b]	23.5	21.1	22.9	20.0	21.3	21.7	22.9	31.8	27.9
MN	Anoka	0	0	0	0	0	0	0	0	0
MN	Benton	0	0	0	0	0	0	0	0	0
MN	Carver	**1**	0	0	0	0	0	**1**	**1**	0
MN	Chisago	0	0	0	0	0	0	0	0	0
MN	Dakota	0	0	0	0	0	0	0	0	0
MN	Hennepin	**123**	**3**	**7**	0	**5**	**1**	**36**	**211**	**61**
MN	Isanti	0	0	0	0	0	0	0	0	0
MN	Kanabec	0	0	0	0	0	0	0	0	0
MN	Kandiyohi	0	0	0	0	0	0	0	0	0
MN	McLeod	0	0	0	0	0	0	0	0	0
MN	Meeker	0	0	0	0	0	0	0	0	0
MN	Mille Lacs	0	0	0	0	0	0	0	0	0
MN	Morrison	0	0	0	0	0	0	0	0	0
MN	Pine	0	0	0	0	0	0	0	0	0
MN	Ramsey	**25**	0	**39**	0	**5**	0	**14**	**112**	**23**

TABLE 4.5-2 (CONTINUED)
NUMBER OF CENSUS BLOCKS WITH MINORITY AND LOW-INCOME POPULATIONS WITHIN THE 50-MILE RADIUS OF MNGP

State		Black or African American	American Indian and Alaska Native	Asian	Native Hawaiian and Other Pacific Islander	Other Single Minority	Two or More Races	Hispanic	Aggregate Minority	Low Income
	Regional Percent[a]	**3.5**	**1.10**	**2.90**	**0.04**	**1.30**	**1.70**	**2.90**	**11.8**	**7.9**
	Threshold for Minority Population[b]	**23.5**	**21.1**	**22.9**	**20.0**	**21.3**	**21.7**	**22.9**	**31.8**	**27.9**
MN	Scott	0	0	0	0	1	0	**1**	**1**	0
MN	Sherburne	0	0	0	0	0	0	0	0	**1**
MN	Sibley	0	0	0	0	0	0	0	0	0
MN	Stearns	0	0	0	0	0	0	0	0	**6**
MN	Washington	0	0	0	0	0	0	0	0	0
MN	Wright	0	0	0	0	0	0	0	0	0
	Total	**149**	**3**	**46**	0	**11**	**1**	**52**	**325**	**91**

Source: Reference 27.

a. Regional percent calculated using the summary data from each county with at least one block group located within the 50-mile radius.

b. At least 20 percentage points greater than the regional percent.

5.0 COST - BENEFIT ANALYSIS

The Company estimates that the MNGP extended power uprate project will result in a net present value savings of $200 to $540 million over the remaining life of the plant. The required capital investment costs will be more than offset by fuel and emission savings, and by the avoided cost of additional capacity. These savings will be directly passed on to the Company's ratepayers.

The Company used the resource planning software Strategist to evaluate the uprate project in comparison to other capacity alternatives. The model performs detailed simulations of the NSP system to estimate operational cost impacts and performs rigorous accounting calculations to forecast the cost recovery of capital projects. Strategist is widely used throughout the energy industry and has been used by the Company in numerous resource plans, certificates of need, and all source solicitations.

The MNGP uprate project was compared to coal, biomass, and natural gas based alternatives as part of the Company's 2007 Integrated Resource Plan. The 71MW uprate project was the least cost option followed by natural gas, then coal, and the biomass based alternative was estimated to be the most expensive.

The costs and benefit of the various alternatives can be categorized into three groups.

1. Capital and Fixed Costs
2. Operating Costs
3. Emission Costs

In general, the capital cost for the uprate project is lower than the expected capital costs for either new biomass or new coal based generation. However, in comparison to natural gas, the uprate project has a higher capital cost. The impact on annual fixed O&M costs is expected to be negligible. The Net Present Value (NPV) of ratepayer benefit from the MNGP uprate project for capital and fixed costs is estimated to be in the range of $151 to $188 million.

Operating cost savings are primarily due to decreased fuel costs. Other elements include variable O&M and the avoided cost of additional purchased power. The operating costs of the natural gas option were very high and canceled out its lower capital cost. The NPV of ratepayer benefit from the MNGP uprate project for operating cost is estimated to be in the range of $77 to $267 million.

Emission costs were decidedly lowest for the uprate project in comparison to the alternatives. While the Company imputed costs to many air emissions as detailed in Table 4.0-1, the total cost was primarily driven by CO_2. The Company encountered varying opinions regarding the appropriate CO_2 emission rate to be applied to the biomass alternative. While some argue that biomass fuel is carbon neutral, the fact remains that emissions from biomass plants are roughly twice that from coal, and that alternative uses for biomass fuel may likely keep the CO_2 from entering the atmosphere. The Company took the conservative approach of applying the full cost of CO_2 emissions to the biomass alternative. The NPV of ratepayer benefit from the MNGP uprate project for emissions is estimated to be in the range of $81 to $277 million.

Finally, the MNGP uprate project maintains the Company's fuel diversity and provides a natural hedge against fuel cost volatility in the coal and natural gas markets. The Company tested this benefit by varying the fuel cost assumptions used in Strategist. One result was that when natural gas prices were increased by 20 percent the NPV of the MNGP uprate project increased by $70 million.

In summary, all modeling results indicate that the uprate project is in the best interest of ratepayers by lowering total forecasted revenue requirements, reducing exposure to future CO2 regulation, and by maintaining fuel diversity.

6.0 NON-RADIOLOGICAL ENVIRONMENTAL IMPACT

6.1 Terrestrial Effects

6.1.1 Land Use

The MNGP extended power uprate does not result in any activity which will change or otherwise modify the present requirements for land use at the plant site. There are no plans to build facilities or modify access roads, parking areas, or laydown areas. As discussed in 6.1.2.A below, it is possible that onsite transmission/distribution equipment may be replaced/modified to support extended power uprate activities at MNGP. Except for transportation of equipment and routine disposal of waste, extended power uprate maintenance activities are confined to the inner-plant security fenced area. Extended power uprate does not affect the storage requirements for above ground or below ground tanks. Other lands located outside the inner security fence will not be modified or changed to support extended power uprate activities. Extended power uprate does not involve changes to any aesthetic resources and does not involve any impacts to lands with historical or archaeological significance.

NSPM does not anticipate the need to construct additional or new low-level radioactive waste storage buildings to support present or extended power uprate activities. The replaced turbine components will be decontaminated as necessary, and recycled to the extent possible, or transferred to an approved disposal facility.

6.1.2 Transmission Facilities

A. Transmission Design and Equipment

A feasibility study for the MNGP EPU was performed in a manner consistent with the MAPP Design Review Standards (DRS) and Midwest Independent System Operator (MISO) practices for interconnection and transmission studies. The results of this study indicate that some transmission system improvements to existing equipment may be required to support the MNGP generation increase for EPU. The study acknowledges that the results may change depending on which generation projects (and corresponding transmission improvements) listed in the MISO interconnection queue ahead of the MNGP EPU actually progress to construction. This study cannot take the place of the System Impact Study (SIS) effort to be performed by MISO under the Large Generation Interconnection Process (LGIP) which will ultimately determine the required changes to the transmission system, if any, to support the increased generation at MNGP. Any required changes will be completed as directed by MISO.

B. Shock Hazards

Two 345-kV transmission lines (Monticello to Coon Creek and Monticello to Parkers Lake circuits) were originally constructed to connect MNGP to the transmission system and were evaluated in the Final Environmental Statement (FES) for initial operations. However, changes to the 345-kV transmission system and to these lines have fully integrated the Company's Monticello Substation into the 345-kV system. Based on these considerations, the Company's Monticello Substation now constitutes the transmission interconnection for MNGP.

All lines emanating from the Company's Monticello Substation were designed, constructed and are operated in compliance with the applicable sections of the National Electrical Safety Code (NESC®). Specifically, these lines meet the requirement in effect since the 1990 edition of the Code for lines exceeding 98kV alternating current to ground, which limits "the steady state current due to electrostatic effects to 5 milliamp if the largest anticipated truck, vehicle or equipment under the line were short-circuited to ground," (Section 232.C.1.c. and 232.D.3.c.). This current is induced in vehicles by the transmission line electric field, which is proportional to the voltage of the line and inversely proportional to the distance from the line. The Electric Power Research Institute (EPRI) has performed measurements on objects beneath lines to determine the level of electric field that will induce current in various objects. Results indicate that an electric field of 7.8 kV per meter at 1 meter above ground is required to induce a 5 milliamp current through a large tractor trailer. The 345-kV lines associated with MNGP produce a maximum electric field at 1 meter above ground of 6.0 kV per meter. The unloaded sag at 120°F is limited by the NESC® to a minimum distance to ground of 30 feet in order to meet the minimum clearance required for operation at 212°F, which is the highest temperature that Xcel Energy operates the lines (NESC® Section 232). For a large vehicle, the electric field values indicated above could potentially generate an induced current of 3.84 milliamp, which is below the NESC® code criteria of 5 milliamp.

Transmission line compliance with the provisions of the NESC® code discussed above is verified by periodic air patrols (monthly), which monitor construction activities beneath and near the lines that could alter corridor terrain and clearances. Based on these considerations, NSPM concludes that the Monticello 345-kV transmission lines meet the NESC® recommendations for preventing shock from induced currents.

C. Electromagnetic Fields (EMF)

The increased electrical output under EPU conditions will cause a corresponding current rise on the transmission system and this will result in an increased magnetic field. However, according to the NRC Staff, the chronic effects of EMF on humans are unquantified at this time, and no significant impacts to terrestrial biota have been identified (Sections 4.5.4.2.3 and 4.5.6.3.4 of Ref. 5). According to the National Institute of Environmental Health Sciences, the overall scientific evidence for human health risk from EMF exposure is weak and there is no consistent pattern of biological effects (Ref. 8). The chronic effects from EMF exposure have not been conclusively established and scientists are still debating whether EMF is a hazard to health.

6.1.3 Miscellaneous Wastes

Sanitary wastes from MNGP are discharged directly to the Monticello Wastewater Treatment Plant in accordance with a permit issued by the City of Monticello. Acid drains are processed in a retention basin in accordance with NPDES permit requirements. Other waste sources include hazardous waste generation from routine plant operations and air emissions from the plant heating boiler and diesel generators. Effluents from these pathways are controlled as required by state and federal permits. Extended power uprate does not have any significant impact on the quality or quantity of effluents from these sources, and operation under extended power uprate conditions will not significantly reduce the margin to the limits established by the appropriate permits. See Section 6.2.5 herein for additional information on water quality.

6.1.4 Cooling Tower Drift, Icing, and Fog

In Reference 19, the NRC Staff concluded that:

> "Impacts from salt drift, icing, fogging, or increased humidity with cooling tower operation have not been found to be a problem at operating nuclear power plants and are not expected to be a problem during the license renewal period."

Drift, icing, and fog from the MNGP cooling towers have been negligible and have had no discernible impacts on vegetation, agriculture, recreational activities, highway safety, air traffic, or river traffic. The Mississippi River does not contain the salt content of other water sources, and sufficient rainfall is available to prevent undesirable chemical concentrations in the soil from trace chemicals in the drift.

Extended power uprate may involve an estimated extra 20 days of cooling tower operation (see Section 6.2.2 herein). These changes will not have a significant effect on the environment. Assuming cooling tower operation from April to October (seven months), the NRC Staff conservatively estimated a total fogging time of 45 hr/yr in Reference 2. The fogging rate associated with an estimated 150 days of cooling tower operation at extended power uprate conditions is bounded by the fogging rate associated with an estimated 210 days of cooling tower operation (April to October assumed in Reference 2).

6.1.5 Noise

In Reference 19, the NRC Staff concluded that:

> "Noise has not been found to be a problem at operating plants and is not expected to be a problem at any plant during the license renewal term."

Extended power uprate does not result in any significant changes to the character, sources, or energy of noise generated at MNGP. The new equipment necessary to implement extended power uprate will be primarily installed within existing plant buildings. This includes the upgraded HP turbine which will operate at the same speed as the original equipment. The effect of the additional period of cooling tower operation on ambient noise levels is not significant. No new significant noise-generating equipment will be installed outside the plant. No significant increases in ambient noise levels are expected within the plant.

6.1.6 Terrestrial Biota

6.1.6.1 Threatened and Endangered Species

The United States Fish and Wildlife Service (FWS) has designated 11 species known to occur in Minnesota as threatened or endangered at the federal level and four species known to occur in the state as candidates for such listing (Ref. 28). However, only one of these species, the Higgins' eye pearlymussel (*Lampsilis higginsii*) is indicated by the Minnesota Department of Natural Resources (MNDNR) as occurring in the vicinity of MNGP (Ref. 25). Similarly, threatened and endangered species have been designated at the state level under programs administered by the MNDNR as implemented by Minnesota Rule 6134.0150. Three bird species, one reptile species, one mollusk species, one insect species, and one plant species designated as endangered or threatened at the state level in Minnesota have been documented by MNDNR as occurring in the vicinity of MNGP or the transmission corridors of interest. Pertinent information related to the status of these species is provided in the following sections (see Table 6.1.6.1-1). Note that the bulk of the information provided in the Section 6.1.6.1 subsections is retained from Reference 27 unless otherwise referenced.

ENCLOSURE 4

TABLE 6.1.6.1-1
THREATENED AND ENDANGERED SPECIES OCCURRING IN THE VICINITY OF MNGP AND THE ASSOCIATED TRANSMISSION CORRIDORS[a]

		Status[b]	
Common Name	**Scientific Name**	**Minnesota**	**U.S.**
Birds			
Loggerhead Shrike	*Lanius ludovicianus*	T	
Peregrine Falcon	*Falco peregrinus*	T	
Trumpeter Swan	*Cygnus buccinator*	T	
Reptile			
Blanding's turtle	*Emydoidea blandingii*	T	
Mollusks			
Higgins' eye pearlymussel	*Lampsilis higginsii*	E	E
Insects			
Uncas Skipper	*Hesperia uncas*	E	
Plants			
Tall Nut-rush	*Scleria triglomerata*	E	

a. Based on occurrences reported by the MNDNR in the Minnesota Natural Heritage database (Ref. 29) and Reference 25.
b. E = Endangered, T = Threatened

6.1.6.1.1 Fauna

The bald eagle was originally included in the above table for the MNGP License Renewal Environmental Report (Ref. 27). The bald eagle is known to occur in the vicinity of the MNGP site. Originally listed as endangered by the FWS in 1967, the bald eagle was down-listed to threatened in 1995, and was de-listed in 2007 (Ref. 22). Several factors aided in the recovery of this species including a national ban on DDT and other organochlorine pesticides by the EPA in mid-1970's and the reduced use of lead shot for waterfowl hunting. These efforts have considerably benefited bald eagle populations in the State of Minnesota. The state's first bald eagle survey in 1973 found 115 active nests; by 1995 the survey found over 600. In 2000, MNDNR surveyed over 1,300 known breeding areas and identified 681 occupied nests in the state, 76.5 percent of which included young. The 2000 survey documents the continuing recovery of the species. In comparing the early survey results with year 2000 data, MNDNR concluded that Minnesota's bald eagle population is growing at a slower but healthy level. Bald eagles are typically found near forested rivers and lakes where there is ready access to preferred nest sites and food. Preferred nesting habitat includes tall trees or cliffs. Bald eagles primarily prey on fish and ducks. Bald eagles are known to nest in the vicinity of the MNGP site.

Three bird species listed as threatened by the State of Minnesota are known to occur either on or in the vicinity of MNGP and associated transmission corridors of interest: peregrine falcon (*Falco peregrinus*), loggerhead shrike (*Lanius ludovicianus*), and trumpeter swan (*Cygnus buccinator*). Though peregrine falcon populations were greatly reduced in the 1950's and 60's by the effects of pesticide poisoning, reintroduction programs are having success in Minnesota. Peregrine falcons prefer open wetlands where there is access to nesting sites on cliffs, such as those along the Mississippi River Valley and Lake Superior. This species also demands a ready supply of prey such as ducks, shorebirds, and seabirds. However, they have proven to be adaptable. MNDNR reported that in 2003, 25 pairs successfully raised 48 young at traditional cliff sites and new man-made habitats which include power plant stacks, skyscraper balconies and rooftops, and bridges. With the installation of a nest box on the MNGP Off Gas Stack in 1992, peregrine falcons have been successfully nesting at the site since 1995. Since 1993, peregrine falcons have also been successfully nesting at the Sherco site, which is five miles upstream from MNGP.

Loggerhead shrikes are known to occur on and in the vicinity of MNGP and are documented in several areas along the transmission corridor in Anoka and Sherburne Counties. Preferring open country and dry upland prairie with hedgerows, shrubs, and small trees, the birds can also be found around planted shelterbelts of trees, old orchards, pastures, cemeteries, grassy roadsides, and farmsteads. The scattered trees, shrubs, and fencerows in these areas provide places for the shrikes to hunt and rest. Power lines are used as perches from which to hunt as well. Red cedar, hawthorn (*Crataegus spp.*) and plum (*Prunus americana*) trees are often used for nesting.

In recent years, wintering trumpeter swans have been observed in increasing numbers on the Mississippi River downstream from MNGP. The swans in this area are drawn to the open water in the winter months, which results from MNGP's discharge of warm water to the River, and to food supplied by a local resident at the City of Monticello's Mississippi Drive Park. Having disappeared from Minnesota in 1880's, the trumpeter swan has been successfully restored to the state with recent MNDNR and FWS surveys showing more than 75 nesting pairs and nearly 900 year round residents.

One reptile species, the Blanding's turtle (*Emydoidea blandingii*) is listed by the State of Minnesota as a threatened species and is documented by MNDNR as occurring in the vicinity of the transmission corridors in Anoka and Sherburne Counties. The turtles require both wetland and upland habitats to complete their life cycle. In Minnesota, the turtles are primarily marsh and pond inhabitants. Calm, shallow water bodies with mud bottoms and abundant aquatic vegetation, such as cattails, and water lilies are preferred, though extensive marshes bordering rivers are also suitable habitat for the turtles. Nesting occurs in open (grassy and brushy) sandy uplands.

One mollusk species, the Higgins' eye pearlymussel (*Lampsilis higginsii*) is listed by both the U.S. Fish and Wildlife Service and the MNDNR as an endangered species and occurring in the vicinity of MNGP (Ref. 25, Ref. 28). The Higgins' eye is a medium-sized (reaching approximately 100 mm in length) freshwater mussel with a smooth, yellow, yellowish green, or brown with green rays that are obscure on some individuals. Like other freshwater mussels, the Higgins' eye feeds by filtering food particles from the water column. The specific food habits of the species are unknown, but other juvenile and adult freshwater mussels have been documented to feed on detritus, diatoms, phytoplankton, and zooplankton. The diet of Higgins' eye glochidia, like other freshwater mussels, comprises water (until encysted on a fish host) and fish body fluids (once encysted). Higgins' eye has been characterized as a large river mussel species. No correlation was found between overall mussel density and substrate size in the Wisconsin River where Higgins' eye was found. It was found that burrowing times for Higgins' eye were similar in clay, silt and sand, but longer in pebble-gravel substrate. The species is not associated with firmly packed clay, flocculent silt, organic material, bedrock, concrete, or unstable moving sand. It has been indicated that Higgins' eye were most common in sand/gravel substrate. Substratum that was free of plants and consisted of stable, gravelly sand was considered as suitable. It was also noted that immediately downstream of wingdams, mussel diversity was high and new species were found at a more rapid rate on the wingdam than in gravelly sand. The species was found immediately below the wingdam at McMillan Island and has been collected on wingdams near Prairie du Chien. Higgins' eye may be primarily adapted to large river habitats with moderate current, such as the East channel of the Mississippi River near Prairie du Chien, Wisconsin. Water velocities less than 1 meter per second during periods of low discharge are considered ideal for this species. (Higgins' Eye information from Ref. 26)

One insect species, the Uncas skipper (*Hesperia uncas*), a state-listed endangered species, is documented by MNDNR as occurring in the vicinity of the transmission corridor in Sherburne County. Preferred habitat for the Uncas skipper includes short-grass prairie and open woodlands. Adults feed on flower nectar, and the plant hosts for the caterpillar stage are blue grama grass (*Bouteloua gracilis*) and needlegrass (*Stipa sp.*). Though found in many areas of the western North America, where arid environments are common, the Uncas skipper is listed as endangered in Minnesota because of habitat scarcity. With fire no longer a natural part of the regional ecosystem, forestation of former savanna has occurred and reduced the available habitat.

6.1.6.1.2 Flora

Tall nut-rush (*Scleria triglomerata)* is a state-listed endangered species documented by MNDNR as occurring in the vicinity of the transmission corridor. Tall nut-rush can be found in dry or moist sandy ground and tolerates open to shaded light conditions. It is found in prairies and in the borders of marshes. Common or indicator plant associates in dry sand prairie habitats include bluejoint grass, cordgrass, rush, sedges, twig-rush, and shrubby cinquefoil. In wet-mesic prairie habitats common or indicator plant associates include big bluestem, little blue stem, cord grass, prairie dropseed, and bee-balm.

6.1.6.1.3 Terrestrial Biota Conclusion

The EPU project does not involve land disturbance or a measurable increase in noise levels outside the plant. The project also does not increase the size of the MNGP workforce or change right-of-way maintenance practices. As a result, there will be no impacts to terrestrial biota (including threatened or endangered species) beyond those described in the FES for operation and the Generic Environmental Impact Statement for MNGP License Renewal.

6.2 Hydrology

6.2.1 Groundwater

Extended power uprate does not affect groundwater resources and does not involve significant increases in the consumptive use of these resources at MNGP. Station groundwater use is governed by water appropriation limits of the MNDNR. The domestic water supply is obtained from six wells located on the plant property. No dewatering or collector-type wells (Ranney wells) are used at MNGP. The Domestic Water System, which is serviced by two 100 gpm wells, provides domestic water to lavatories, showers, and laundries and provides raw water to the reverse-osmosis system and seal water to certain pumps located at the plant intake structure. Groundwater appropriation permit number 670083 (issued by MNDNR) establishes limits associated with these 100 gpm wells. Extended power uprate does not affect compliance with these limits. The annual appropriation limit is 20 million gallons and average annual usage over the last five years (2002-2007) is less than 17 million gallons. Any increases in makeup to plant systems under extended power uprate from these sources are expected to be minor, and operation within the allowable limit will continue. Four smaller capacity wells (that are not required to be addressed via a groundwater appropriation permit) provide water to office, warehouse, and security facilities not serviced by the Domestic Water System. The wells are of standard vertical construction. Extended power uprate has no effect on these sources.

6.2.2 Surface Water Appropriation

Surface water use at MNGP is in accordance with the water appropriation limits of the MNDNR. Under surface water appropriation permit number PA 66-1172-S, the Company may withdraw a maximum of 645 cubic feet per second (cfs) of water from the Mississippi River at MNGP. Special operating restrictions apply at lower than average river flows of 860 cfs and 240 cfs. Extended power uprate does not introduce any significant changes to the screen wash, service water, or circulating water flow requirements. Extended power uprate does not involve any changes to the water appropriation requirements of this permit.

Currently, the surface water consumption due to open cycle evaporative losses and cooling tower evaporation and drift is estimated at approximately 6,800 acre-ft/year assuming 130 days of cooling tower operation, 235 days of open-cycle operation and nominal values of cooling tower flow (approximately 509 cubic feet/second). Using the maximum surface water appropriation limit of 645 cubic feet/second as the cooling tower flow value results in an estimated total consumption of 7,800 acre-ft/year.

For extended power uprate, assuming an increase in open cycle consumption of 20 percent, an increase in days of cooling tower operation to 150 days/year, and nominal values of cooling tower flow, results in an estimated consumption of 7,700 acre-ft/year. Using the maximum surface water appropriation limit of 645 cubic feet/second as the cooling tower flow value results in an estimated total consumption of approximately 8,700 acre-ft/year. Note that using the appropriation limit for cooling tower flow is very conservative because the cooling towers are typically operated in "Helper" mode (i.e., not all circulating water flow is passed over the cooling towers).

Even the most conservative estimate (i.e., 8,700 acre-ft/year) of consumption is below the value of 9,000 acre-ft/year that has been previously evaluated by the NRC in the MNGP FES (Ref. 2) for a combined consumption of open cycle and cooling tower operations. This estimate is also well below the 13,000 acre-ft/year the NRC evaluated in Ref. 19 and concluded that "the consumptive loss due to evaporation from the cooling towers represents four percent of the river flow, which is not considered significant." The NRC further concluded that "the staff expects that the existing State restrictions on water withdrawal during low-flow conditions in the Mississippi River are appropriate and no additional mitigation measures are warranted." The nominal value of 7,700 acre-ft/year, which is most representative of actual cooling tower operating flow rates, is well below the 9,000 acre-ft/year value used in the FES (Ref. 2) and the 13,000 acre-ft/year referenced in Ref. 19.

Additionally, cooling tower operation at power uprate conditions is estimated at 150 days per year which is less than the FES assumption of approximately 210 days per year (April through October).

In conclusion, the estimated additional consumption due to extended power uprate is bounded by values previously evaluated by the NRC and is not considered to be significant.

6.2.3 Discharges

Surface water and wastewater discharges are regulated by the State of Minnesota. The National Pollutant Discharge Elimination System (NPDES) permit is periodically reviewed and re-issued by the Minnesota Pollution Control Agency (MPCA). The present NPDES permit for MNGP, permit number MN0000868, which expires September 30, 2012, authorizes discharges from five stations. The stations and their effluent limits are listed in Table 6.2.3-1 herein. None of the limits listed in this table will require modification to implement extended power uprate. Additionally, Attachment A contains a summary of the environmental authorizations for current plant operations.

ENCLOSURE 4

Table 6.2.3-1. NPDES Discharge Limit Summary

Discharge Station No.	Description	Parameter	Limit
SD001	Plant Cooling Water	Flow (mgd) Phosphorus Total (as P) Bromine (as Br) Chlorination Chlorine Rate Oxidants, Total Residual Plant Capacity Factor, Percent of Capacity Temperature, Water	Monitor Only Monitor Only Monitor Only 2.0 hr/day Monitor Only 0.2 mg/l (instantaneous maximum) Monitor Only Seasonal[a]
SD003	Holdup Pond Effluent	Flow (mgd) Total Suspended Solids pH Phosphorus Total (as P)	Monitor Only 9.9 kg/day monthly average 30 mg/l monthly average 33.2 kg/day daily maximum 100 mg/l daily maximum pH (6.0 to 9.0) Monitor Only
SD004	Turbine Building Sump & Misc Discharge	Flow (mgd) Total Suspended Solids pH Oil and Grease, Total Recoverable (Hexane Extractions)	Monitor Only 12.7 kg/day monthly average 30 mg/l monthly average 42.3 kg/day daily maximum 100 mg/l daily maximum pH (6.0 to 9.0) 4.2 kg/day monthly average 10 mg/l monthly average 15 mg/l daily maximum 6.3 kg/day maximum calendar week average
SD005	Screen Backwash	Flow (mgd)	Monitor Only
SD006	Roof/Yard Drains and Screen Backwash	Flow (mgd)	Monitor Only
SW001	Water intake	Phosphorus Total (as P) Temperature, Water	Monitor Only Monitor Only
WS001	Mid-downstream discharge canal	Oxidants, Total Residual	0.05 mg/L daily maximum

[a] In no case shall the maximum daily average temperature at the end of the discharge canal exceed the following limits:

(i) During the months of April through October: 95 °F
(ii) During the months of November and March: 85 °F
(iii) During the months of December through February: 80 °F

6.2.4 Increase in Circulating Water Discharge Temperature

At extended power uprate conditions, the heat rejected by the condenser increases. This results in a corresponding increase in the circulating water outlet temperature for a given system flow rate. The steam cycle heat dissipation is provided by the Circulating Water System and the Cooling Tower System. The heat dissipation system at MNGP is the source of thermal discharges from the plant. No physical modifications or operational changes are required for these systems to implement extended power uprate.

The NPDES permit issued by the MPCA limits maximum average daily discharge temperatures at the end of the discharge canal (Note 'a' to Table 6.2.3-1 above). Extended power uprate will not involve any changes to the MPCA discharge temperature limits. The slight discharge canal temperature increase will not result in one half of the surface width of the river temperature exceeding the 90°F maximum as delineated in the FES. Extensive field studies have been performed to confirm that the limits imposed by the NPDES permit are conservative and assure no significant adverse impact on the environment. These temperature studies ended in 1988 when the MPCA determined that 20 years of temperature monitoring had adequately characterized the thermal impacts of MNGP operation. Based on studies that evaluate the MNGP impact on the river ecosystem, cooling tower operation during the summer months has adequately prevented detrimental environmental effects and water temperatures downstream are not high enough to harm aquatic species or impede fish migration even in summer months. Temperature monitoring of outfall SD001 (discharge canal) is continuous, and NSP has consistently operated MNGP in conformance with the permit's thermal discharge requirements.

The temperature increase across the intake and plant discharge is highest in fall and winter, when once-through cooling is employed. The temperature increase is lowest in summer and during periods of low river flow, when NPDES permit limits associated with upstream average river temperature necessitate cooling tower use. During open cycle operation at rated circulating water system flow, it is conservatively estimated that extended power uprate will result in an increase in temperature of water entering the discharge canal by approximately 4.5°F. During other modes of operation, the water temperature increase will be less due to tempering from partial or full cooling tower operation. The calculated temperature increase of 4.5°F at the discharge canal inlet would be experienced during those months where cooling tower operation is not required to meet NPDES permit temperature requirements. This resultant discharge canal temperature increase is well bounded by seasonal variations. During combinations of high river temperature and high atmospheric temperatures, discharge canal temperatures have approached the NPDES permit limits with cooling tower operation. During such periods NSP has reduced power at MNGP to maintain compliance with the NPDES permit. This practice will continue under extended power uprate conditions.

A 4.5°F inlet temperature increase would not involve any significant increase in harmful thermophilic organisms in the discharge canal. MNGP daily average discharge canal temperatures range from 66 to 95°F when the plant is operating and rarely average more than 90°F over a month. Thermophilic bacteria generally occur at temperatures of 25 to 80°C (77-176°F), with maximum growth at 50 to 60°C (122-140°F). Pathogenic forms have evolved to survive in the digestive tract of mammals and, accordingly, have optimum temperatures of around 37°C (99°F).

Similarly, pathogenic protozoans such as *Naegleria fowleri* have maximum growth and reproduction at temperatures ranging from 35 to 45°C (95-113°F) and are rarely found in water cooler than 35°C (95°F).

Because of NPDES permit requirements, MNGP discharge canal temperatures are below those optimal for growth and reproduction of pathogenic microorganisms because of NPDES permit requirements, but could permit limited survival of these organisms in summer months. The heated effluent flows over a weir at the end of the discharge canal which promotes atmospheric mixing and cooling before entry into the Mississippi River. Temperatures in the Mississippi River immediately downstream of MNGP are consistently several degrees cooler than those in the discharge canal and under normal extended power uprate conditions would not accelerate the propagation of these pathogenic organisms. Another factor limiting concentrations of pathogenic microorganisms in the MNGP discharge is the absence of a seed source or inoculant. Wastewater, whether municipal sewage, industrial wastewater, or agricultural runoff, is usually the source of pathogens in natural waters. Since October 1983, MNGP has pumped its sanitary wastes to the City of Monticello's wastewater treatment plant. Consequently, the extended power uprate does not involve significant discharges of pathogenic microorganisms to the discharge canal and the Mississippi River. Pathogenic organisms in the Mississippi River downstream of MNGP would typically come from upstream anthropogenic sources or animal wastes.

MNGP operation at the extended power uprate power level is not expected to stimulate growth and reproduction of pathogenic microorganisms in the Mississippi River downstream of the plant. Under certain circumstances these organisms may be present in the discharge canal but not in sufficient concentrations to pose a threat to downstream water users. It should be noted that many of these pathogenic microorganisms (e.g., *Pseudomonas*, *Salmonella*, and *Shigella*) are ubiquitous in nature, occurring in the digestive tracts of wild mammals and birds, but are usually only a problem when the host is immunologically compromised.

Given the above, the slight increases in circulating water outlet temperature due to extended power uprate will not involve any changes to NSPM's compliance with the present discharge temperature limits established by the Minnesota Pollution Control Agency (MPCA) and will not result in any significant impacts to the environment.

6.2.5 Water Quality

The Mississippi River at the point of discharge for MNGP is classified as Class 2Bd by the State of Minnesota. Class 2Bd water quality is sufficient to allow for water sports, fishing, and aquatic recreation.

Based on 20 years of water quality monitoring at MNGP, the Company submitted a report for review by the MPCA in 1987. In 1988, the MPCA determined that MNGP operation had not adversely affected the water quality of the Mississippi River downstream of the plant and allowed the Company to reduce the monitoring program. There is no indication that chemical discharges from MNGP have caused any detrimental effects to the aquatic biota. The MPCA determined that water temperature was the only physicochemical parameter significantly affected by plant operation.

Effluent limitations and monitoring requirements for the plant discharges are an integral part of the NPDES permit. Each outfall identified in the permit requires continuous flowrate monitoring. Modifications of the non-radiological drain systems or the retention basin system are not required due to extended power uprate, and biocide/chemical discharges will be consistent with existing permit limits. Extended power uprate will not introduce any new contaminants or pollutants and will not significantly increase the amount of those potential contaminants presently allowed for release by the MPCA other than noted below.

NSPM has determined that approximately 20 additional days of cooling tower operation may be required to support extended power uprate. This is due to the present MPCA permit limit of 95 deg F for the Daily Maximum plant cooling water discharge temperature between April and October. Bromine and sodium hypochlorite are injected into plant water systems at various concentrations to minimize microbiological fouling. The additional 20 days of operation may require a very slight increase in normal bromine and sodium hypochlorite injection. The discharge of any additional residual halogens attributable to the extra 20 days of cooling tower operation is expected to be insignificant, and effluent concentrations would continue to be well below the NPDES daily discharge limits.

6.2.6 Mississippi River Thermal Plume

The results of the Section 316(a) demonstration (Ref. 6) for MNGP determined that MNGP operation has had subtle alterations in the structure of some aquatic communities, but these impacts have been limited to a small area directly downstream of the plant. Biological diversity has not suffered and may have been enhanced by thermal inputs during certain times of the year. Based on available information, the minor increase in thermal output to the river due to extended power uprate is not expected to result in any impacts on aquatic biota that are different in kind or greater in magnitude than those identified over the past years of plant operation and will not alter the previous 316(a) demonstration.

In addition to the 316(a) demonstration, the Company conducted thermal plume studies following the construction of the discharge canal weir. These studies showed that even in the worst case year the thermal plume disperses rapidly, is largely restricted to the near side of the river and is not a barrier to fish movement. In addition, depending on the ambient conditions and the distance downstream from the plant, roughly 30 to 70 percent of the river is unaffected by the heated discharge. Extended power uprate does not alter the water volume requirements for the heat dissipation system, the physical construction of the discharge canal terminus, or the temperature limits established by the NPDES permit. Therefore, extended power uprate conditions do not change the findings of the thermal gradient and plume studies.

6.2.7 Cold Shock

MNGP is equipped with once-through cooling system coupled with cooling towers that can operate in various modes to meet permit requirements for water appropriations and thermal discharge. The use of the system in a once-through capacity requires evaluation of the effects of the heated discharge on biological resources of the Mississippi River.

Cooling water is withdrawn from the Mississippi River using two, 140,000 gallons per minute (gpm) circulating water pumps. The water is circulated through the condenser and then routed, along with service water, to the discharge structure. During open cycle operation, i.e., when ambient river water temperature is less than 68 degrees Fahrenheit (°F) (and river flow is adequate), the condenser effluent is routed to an open canal and discharged directly to the river. Open-cycle operation is typical from about mid-September to mid-May. When river water temperatures exceed 68°F and river flow is adequate, condenser effluent from the discharge structure is pumped into two, induced-draft cooling towers, and then to the river via the discharge canal. Under high temperature and/or low flow conditions, MNGP can also be operated in a partial recycle mode or closed-cycle mode. These alternative operating modes are used to comply with MNDNR water appropriation restrictions and MPCA thermal discharge limits established in the NPDES permit.

The 316(a) demonstration for MNGP (Ref. 6) summarized the extent and behavior of the thermal discharge plume under various conditions. The author's observations were based on 34 plume-mapping surveys conducted between 1971 and 1973. Compliance with State water quality standards and draft NPDES permit conditions was not always achieved, and compliance was dependent primarily on plant operating mode and river flow. Particularly under extreme summer low flows, compliance was not possible with or without cooling towers. Occasional non-compliance was documented during the fall through spring period. Notwithstanding some periods of non-compliance with draft NPDES permit conditions and water quality standards, the 316(a) demonstration (Ref. 6) concluded, based on a review of pertinent ecological studies, that there had been no "indication of prior appreciable harm to the biota of the Mississippi River within the area of influence of MNGP." This evaluation included all major biotic groups including phytoplankton, periphyton, macrophytes, zooplankton, benthic macroinvertebrates, and fish. The Company notes that when river conditions (i.e., flow and temperature) limit the ability for MNGP thermal discharge to meet the State water quality standards, plant procedures call for a reduction in power output to maintain current NPDES permit compliance.

One aspect of the thermal plume evaluation discussed in the 316(a) demonstration was the attraction of fish to the discharge canal in winter, and their vulnerability to cold shock mortality in the event of a plant shutdown. This may occur when fish enter the warm effluent during fall/winter and become acclimated, and then are subjected to a near instantaneous drop to ambient temperature when the plant shuts down. There were eight winter shutdown events between 1975 and 1979 resulting in the cold shock death of numerous fish. Concerns about this phenomenon resulted in the construction of a fish barrier-weir at the mouth of the discharge canal in 1980. This weir prevents fish from entering the warmest part of the discharge, and has reduced the frequency and severity of cold shock kills. Since 1980, there have been 13 events with a total loss of 5,399 fish. In 2007, there were two events that resulted in fish kills. There were 3,559 fish killed related to the plant scram on January 10, 2007 and there were 27 fish killed as the plant dropped power for the refueling outage. Even before installation of the fish barrier-weir, the 316(a) demonstration (Ref. 6) concluded that cold shock mortality did not appear to adversely affect the fish community near the MNGP.

Installation of the fish barrier-weir in 1980 was assumed to have altered the configuration of the thermal plume. Consequently, from 1982 through 1987, temperature surveys were conducted over a six-kilometer reach below MNGP and at upstream control areas on a seasonal basis. During the worst-case year of 1983, the plume reached approximately six kilometers downstream. Excess temperatures (above ambient) during winter in the main body of the plume ranged from 26°F just below the discharge to 12°F six kilometers downstream at the State Highway 25 Bridge. However, the main body of the plume was confined to the right (south) bank of the river and rarely spanned the entire river. Depending on conditions and location, from 30 to 70 percent of the river was always generally unaffected by the thermal plume.

One of the most valuable tools for assessing the effects of the MNGP thermal plume on the river is the fishery monitoring database compiled by NSP since the mid-1970s. This database contains a more than 30-year annual record of electrofishing and seining results both up- and downstream of the MNGP site. Electrofishing catches from 2004 through 2007 (Ref. 23) were dominated by shorthead redhorse, silver redhorse, common carp and smallmouth bass with lesser numbers of channel catfish, and other species. Minnows dominated the seine catches, primarily spotfin shiner and sand shiner. Changes noted in the fish community have been unrelated to the MNGP thermal discharge, such as the invasion of channel catfish in the late 1980s and subsequent growth of the population. Examination of the annual fish monitoring data confirms that a "balanced, indigenous community" of fish has been maintained in the river throughout the operational period of MNGP.

Cold shock can be caused by plant shutdown in the winter, and the probability of a plant shutdown is independent of extended power uprate. The projected increase in discharge canal inlet temperature of 4.5°F at extended power uprate conditions will not result in a significant increase in the overall discharge canal temperature, and the magnitude of the temperature decrease in a cold shock situation is not significantly changed. The cold shock concerns of aquatic river species have been reduced by the construction of a weir at the end of the discharge canal. The weir and the traveling screens limit the amount of aquatic species in the discharge canal and reduce the effects of cold shock on aquatic species in the discharge canal. In addition, administrative procedures for controlled temperature reduction of the discharge canal are in place to minimize thermal shock to the aquatic biota. The consequences of a cold shock event have been reduced at present and these practices will be continued under extended power uprate operating conditions.

6.2.8 Impingement and Entrainment

MNGP uses a once-through cooling water system in combination with two mechanical draft cooling towers, enabling the plant to operate in various modes. Operating experience indicates that historically MNGP operates in open or helper cycle approximately 98 percent of the time.

Section 316(b) of the Clean Water Act requires any standard established pursuant to 301 or 306 shall require the location, design, construction, and capacity of cooling water intake structures to reflect the best technology available for minimizing adverse environmental impacts [33 USC 1326 (b)]. Entrainment of fish and shellfish in the early life stages through the condenser cooling system is one of the potential adverse environmental impacts that can be minimized by the use of the best available technology.

A 316(b) demonstration was developed and submitted to the MPCA (Ref. 4). The demonstration was ultimately accepted and approved by the MPCA in September 1979, with the conclusion that entrainment at MNGP "... offers no substantial detriment to the fisheries population." Electrofishing surveys to assess relative abundance and seasonal distribution of fish in response to MNGP's thermal discharge have been conducted from 1976 to the present. Areas of the River sampled extended about 1.5 kilometers both up and downstream from the discharge structure, with the thermal plume generally covering less than one-half of the downstream flow of the study area. Results show similar, persistent, and stable species assemblages both up and downstream of the discharge (Ref. 23). Based on these studies and the fact that water appropriation will not increase under EPU, NSPM concludes that impacts to fish populations as a result of entrainment is not altered under EPU conditions.

Upon review of the 316(b) demonstration, the MPCA concurred that impingement at MNGP "... offer no substantial detriment to the fisheries population". Based upon the same studies discussed above for entrainment, and the fact that water appropriation will not increase under EPU, NSPM concludes that impacts to fish populations as a result of impingement is not impacted by operation at extended power uprate conditions.

The current MNGP NPDES Permit addresses 316(b) compliance. It states that MNGP "shall operate the intake structures consistent with Section 316(b) of the Clean Water Act and consistent with the MPCA-approved 1978 report "Section 316(b) demonstration for the Monticello Nuclear Generating Plant..." The reissued permit has a requirement that MNGP submit the results of an impingement mortality and entrainment sampling effort to the MPCA within one year of permit reissuance. The NPDES Permit further states that "If MPCA review of the evaluation data leads to the conclusion that the facility needs to install technology or modify operations to reduce impingement mortality and/or entrainment the permit may be reopened to include a compliance schedule developed using best professional judgment."

Extended power uprate does not effect the impingement and entrainment of organisms and will not cause effects that have not been previously evaluated. The circulating water and service water system flow rates are not being changed for EPU. Therefore, no increase in entrainment of organisms or impingement of fish is anticipated at extended power uprate conditions above that for present operating conditions. Since initial operation, the Company has modified the MNGP intake structure to reduce impingement impacts. These modifications include a dedicated sluiceway for the traveling screen backwash system to allow aquatic species impinged on the screens to be returned to the river during backwash cycles to minimize impingement mortality. The practice of backwashing of the traveling screens to the river when river temperature is above 50°F has also reduced the potential for organism impingement mortality.

The NRC Staff estimated that operation of MNGP at average river flows and intake flows of 640 cfs may entail a possible mortality rate of up to 15 percent of passing drift organisms through entrainment (Summary and Conclusions, Ref. 2). Studies at MNGP, conducted during low flow conditions before the modifications above were implemented, indicate an entrainment rate of 19 percent of the total drift organisms. Because of the study year bias due to low flow conditions, the NRC Staff's estimate on mortality is consistent with plant operating data. Because there will be no increase in river water appropriation, extended power uprate has no effect on the entrainment rate associated with present operating conditions.

7.0 RADIOLOGICAL ENVIRONMENTAL IMPACT

7.1 Radioactive Waste Streams

The radioactive waste systems at MNGP are designed to collect, process, and dispose of radioactive wastes in a controlled and safe manner. The design bases for these systems during normal operation is to limit discharges in accordance with 10 CFR 20 and to satisfy the design objectives of Appendix I to 10 CFR 50 (Section 9 of Ref. 7). These limits and objectives will continue to be adhered to under extended power uprate.

In addition, operation at extended power uprate conditions does not result in any changes in the operation or design of equipment in the solid waste, liquid waste, or gaseous waste systems. The safety and reliability of these systems is unaffected by extended power uprate. Extended power uprate does not affect the environmental monitoring of any of these waste streams, and the radiological monitoring requirements of the MNGP Technical Specifications will not be affected. Extended power uprate does not introduce any new or different radiological release pathways and does not increase the probability of an operator error or equipment malfunction that would result in an uncontrolled radioactive release. The specific effects of extended power uprate on each of the radioactive waste systems are evaluated below.

7.1.1 Solid Waste

NSPM continually tracks the volume of solid radwaste generated at MNGP. Significant volume reductions have occurred over the years. In the 1994-95 timeframe, approximately 50 cubic meters/year was shipped. For calendar years 2001 through 2006, the average volume of solid radwaste (spent resin, filter sludge, evaporator bottoms, etc.) shipped per year was less than 20 cubic meters. The increased volume of resins due to power uprate (estimated at approximately 3 cubic meters/year) could be accommodated in one additional truck shipment per year.

The bulk volume of total solid radwaste shipped from MNGP (in addition to the spent resin, filter sludge, evaporator bottoms, etc.) consists of dry compacted waste, contaminated equipment, etc. This portion of the solid radwaste volume is not directly impacted by power uprate on an ongoing basis but is a factor of the amount and types of housekeeping, maintenance and modification activities performed in the plant. There will likely be a temporary increase in these volumes due to the modifications and equipment replacements in support of power uprate. However, MNGP procedures and practices remain committed to a goal of minimizing the volume of solid radwaste that is created and ultimately requires shipment.

Equipment wastes from operational and maintenance activities, chemical wastes, and reactor system wastes also contribute to solid waste generation. Power uprate does not significantly affect the production or type of equipment and chemical wastes. The effect of power uprate on process wastes and reactor system wastes is evaluated below.

A. Process Wastes

Power uprate conditions will involve small increases in the process wastes generated from operation of the Reactor Water Cleanup (RWCU) filter/demineralizers and the condensate demineralizers.

The changeout limits for the RWCU filter/demineralizers are based on differential pressure and effluent chemistry. It is expected that more frequent RWCU backwashes will occur at power uprate conditions due to chemistry limits. Power uprate will not involve changes in RWCU flow rate or filter performance. NSPM determined that the increase in backwashes for RWCU would likely be less than or equal to 5 total backwashes per year.

The changeout limits for condensate demineralizer operation are based on differential pressure and conductivity. The principal power uprate effect on the Condensate Demineralizer System is increased condensate flow. A consequent result of increased condensate flow is that the vessel differential pressure changeout limit will be reached more frequently. Without modification, it is expected that the spent resin generation from condensate demineralizers will increase. It is estimated that the Condensate Demineralizers will require approximately 15 additional backwashes per year.

The slight increases in solid wastes from the processes above (estimated at approximately 3 cubic meters/year) will not result in waste volumes substantially above present levels.

B. Reactor System Wastes

Reactor system wastes will increase slightly due to operation at power uprate conditions. These wastes are currently stored in the spent fuel pool and are not shipped offsite. An Independent Spent Fuel Storage Installation (ISFSI) operation has been constructed onsite at MNGP and spent fuel is scheduled to be stored there in 2008. It is estimated that the number of irradiated fuel assemblies discharged from the reactor will increase from a nominal 150 assemblies/cycle to approximately 170 assemblies/cycle under power uprate conditions. These additional assemblies will be stored in the existing spent fuel pool and ISFSI facility and therefore the environmental impact will be insignificant.

The volume and activity of waste generated from spent control blades and in-core ion chambers may increase slightly under the higher flux conditions associated with power uprate conditions.

The annual environmental impact of low and high level solid wastes has been generically evaluated by the NRC Staff for a 1000 MWe reference reactor. The estimated activity content of these wastes is given by Table S-4 in 10 CFR 51.51. The evaluation with respect to this table is included in Section 8.1 of this report.

Given the arguments above, the environmental impact due to generation of solid radwaste from power uprate conditions is insignificant.

7.1.2 Liquid Radwaste

Although the Company is authorized to discharge liquid radwaste at MNGP per the FES and the Technical Specifications, the Company has administratively operated Monticello as a zero radioactive liquid release plant since 1972. No change is expected in the zero release policy as a result of power uprate.

The annual liquid volume processed by the Liquid Radwaste System is estimated to increase from approximately 11,000 gals/day to 11,250 gals/day partially due to the increased frequency of RWCU filter/demineralizer and Condensate Demineralizer backwashes as a result of power uprate. This increased frequency is estimated to add approximately 91,000 gallons/year, or about 250 gals/day. This increase is less than two percent of overall system capacity and brings the total useage to about 55 percent of system capacity. In addition, because of the zero liquid radwaste discharge at MNGP, this slight increase in input to the liquid radwaste system will be recycled, not discharged, and therefore will not produce any environmental impact.

Power uprate conditions will not result in significant increases in the volume of fluid from other sources to the Liquid Radwaste System. The reactor will continue to be operated within its present pressure control band. Valve packing leakage volume into the liquid radwaste system is not expected to increase. There will be no changes in reactor recirculation pump seal flow or any other normal equipment drain path. In addition, there will be no impact to the Dirty Radwaste, Chemical Waste, or Laundry Waste subsystems of the Liquid Radwaste System as a result of power uprate since the operating modes and the inputs to these subsystems are independent of power uprate.

With the current low waste generation rate at MNGP and the insignificant effect of power uprate on liquid radwaste generation, it is reasonable to conclude that power uprate will not increase liquid radwastes above presently allowed limits. In addition, power uprate will not affect compliance with the limits of 10 CFR 20 or the guidelines of Appendix I to 10 CFR 50 for liquid effluents at MNGP.

7.1.3 Gaseous Wastes

During normal operation, radioactive gaseous effluents are released through the Reactor Building Ventilation System and the Offgas System pathways. These effluents include small quantities of noble gases, halogens, particulates, and tritium. The dose to individuals from normal gaseous effluent releases at MNGP at the current licensed thermal power level are well within the guidelines of 10 CFR 50 Appendix I and the limits of 10 CFR 20 for all airborne radioactive nuclides. The effluent radioactivity, in curies, of noble gases, iodine, and particulates discharged from MNGP has been reduced steadily and is significantly below discharges during initial operating conditions. Power uprate is expected to increase the production and activity of gaseous effluents approximately 13 percent. This increase is well within regulatory limits.

The gaseous radioactivity of the reactor coolant system is, in part, a function of the extent of fuel defects; the causes of which are independent of power uprate.

MNGP has had a good history with respect to nuclear fuel performance. During the past 30 years of plant operation only two fuel rod defects have occurred. One defect was identified in 1989 and was attributed to a manufacturing problem. The other defect was recently detected in late 2007 and is being managed through applicable core management and power suppression techniques. It is anticipated that this defect will be removed no later than the 2009 refueling outage.

Table 7.1.3-1 presents the gaseous releases from MNGP for the years 2001 through 2006. Table 7.1.3-2 presents the resulting radiation dose assessments for the same time period.

ENCLOSURE 4

Table 7.1.3-1

Radioactive Effluent Releases from 2001 through 2006

Source: Annual Radioactive Effluent Release Reports for MNGP		Gaseous Effluents				Iodines, Particulates, and Tritium	Liquid Effluents	
		Total Release	Release Rate	Percent Tech Spec Reporting Level		Percent Tech Spec Reporting Level	Percent Tech Spec Reporting Level	
				Gamma	Beta		Whole Body	Organ
Quarter	Year	Ci	micro-Ci/sec	%	%	%	%	%
1Q	2001	2.98E+01	3.84E+00	2.83E-02	1.57E-02	6.14E-02	0.00E+00	0.00E+00
2Q	2001	5.67E+01	7.21E+00	2.71E-02	1.27E-02	7.41E-02	2.13E-04	9.76E-05
3Q	2001	4.09E+01	5.15E+00	9.21E-03	2.83E-03	9.25E-02	0.00E+00	0.00E+00
4Q	2001	1.14E+02	1.43E+01	6.06E-02	7.32E-03	4.90E-02	1.50E-05	1.09E-05
1Q	2002	1.06E+02	1.36E+01	3.76E-02	8.30E-03	6.26E-02	0.00E+00	0.00E+00
2Q	2002	4.78E+01	6.07E+00	1.53E-02	3.58E-03	9.17E-02	0.00E+00	0.00E+00
3Q	2002	3.77E+01	4.74E+00	1.11E-02	2.79E-03	9.49E-02	0.00E+00	0.00E+00
4Q	2002	3.54E+01	4.45E+00	9.63E-03	2.28E-03	6.84E-02	0.00E+00	0.00E+00
1Q	2003	4.93E+01	6.34E+00	4.01E-02	2.62E-02	8.82E-02	0.00E+00	0.00E+00
2Q	2003	3.10E+02	3.94E+01	1.93E-01	2.22E-02	1.03E-01	1.08E-04	3.90E-05
3Q	2003	1.04E+03	1.31E+02	7.00E-01	5.55E-02	7.14E-02	0.00E+00	0.00E+00
4Q	2003	8.87E+02	1.12E+02	6.04E-01	6.18E-02	5.39E-02	0.00E+00	0.00E+00
1Q	2004	8.44E+02	1.08E+02	5.62E-01	5.20E-02	5.68E-02	0.00E+00	0.00E+00
2Q	2004	4.54E+02	5.77E+01	2.92E-01	3.51E-02	6.41E-02	0.00E+00	0.00E+00

Table 7.1.3-1 (Continued)

Radioactive Effluent Releases from 2001 through 2006

Source: Annual Radioactive Effluent Release Reports for MNGP		Gaseous Effluents				Iodines, Particulates, and Tritium	Liquid Effluents	
		Total Release	Release Rate	Percent Tech Spec Reporting Level		Percent Tech Spec Reporting Level	Percent Tech Spec Reporting Level	
				Gamma	Beta		Whole Body	Organ
Quarter	Year	Ci	micro-Ci/sec	%	%	%	%	%
3Q	2004	3.54E+01	4.46E+00	1.68E-02	4.90E-03	6.60E-02	0.00E+00	0.00E+00
4Q	2004	3.72E+01	4.68E+00	1.71E-02	8.32E-03	9.54E-02	1.29E-08	3.88E-09
1Q	2005	3.34E+01	4.21E+00	1.96E-02	8.45E-03	2.28E-02	0.00E+00	0.00E+00
2Q	2005	4.21E+01	3.69E+00	2.05E-02	9.03E-03	1.04E-02	0.00E+00	0.00E+00
3Q	2005	3.85E+01	4.95E+00	2.32E-02	9.59E-03	7.70E-02	0.00E+00	0.00E+00
4Q	2005	2.46E+01	3.13E+00	1.20E-02	2.84E-03	2.38E-02	0.00E+00	0.00E+00
1Q	2006	2.60E+01	3.35E+00	9.04E-03	1.64E-03	1.01E-02	0.00E+00	0.00E+00
2Q	2006	3.34E+01	4.25E+00	9.85E-03	1.68E-03	1.21E-02	0.00E+00	0.00E+00
3Q	2006	3.48E+01	4.37E+00	9.99E-03	1.89E-03	1.31E-02	0.00E+00	0.00E+00
4Q	2006	3.70E+01	4.66E+00	1.15E-02	3.97E-03	1.60E-02	0.00E+00	0.00E+00
Averages		1.83E+02	2.31E+01	1.14E-01	1.50E-02	5.74E-02	1.40E-05	6.15E-06
Tech Spec Reporting Limits				5.00E+00	1.00E+01	7.50E+00	1.50E+00	5.00E+00
				mrad/qtr	mrad/qtr	mrem/qtr to any organ	mrem/qtr	mrem/qtr to any organ

ENCLOSURE 4

Table 7.1.3-2

Radiation Dose Assessments from 2001 through 2006

Source: Annual Radioactive Effluent Release Reports for MNGP	10 CFR 50 Appendix I Limits								10 CFR 20		
	10	20	15	5	15	15	3	10	100		
	Gaseous Releases						Liquid Releases		Gaseous Releases		
	Max Site Boundary Gamma		Organ	Maximum Dose to Most Likely Exposed Member of General Public			Max Offsite Dose		Max Dose to Individuals due to Activities Inside Site Boundary		
	Gamma	Beta		Whole Body	Skin	Thyroid	Whole Body	Organ	Whole Body	Thyroid	Max Organ (Skin)
	mrad/yr	mrad/yr	mrem/yr	mrem/yr	mrem/yr	mrem/yr	mrem	mrem	mrem	mrem	mrem
2001	3.00E-03	4.00E-03	1.10E-02	6.00E-03	7.00E-03	1.10E-02	1.61E-05	1.72E-04	1.20E-02	1.40E-02	1.50E-02
2002	1.00E-03	2.00E-03	1.40E-02	6.00E-03	8.00E-03	1.40E-02	0.00E+00	0.00E+00	1.40E-02	1.80E-02	1.60E-02
2003	2.20E-02	1.70E-02	4.70E-02	3.90E-02	7.30E-02	4.70E-02	2.45E-07	5.55E-07	2.00E-02	3.00E-02	3.00E-02
2004	1.30E-02	1.00E-02	3.70E-02	2.20E-02	3.70E-02	3.70E-02	1.94E-10	1.94E-10	9.00E-03	1.10E-02	9.00E-03
2005	3.00E-03	3.00E-03	2.50E-02	1.60E-02	2.50E-02	2.50E-02	0.00E+00	0.00E+00	1.50E-02	1.60E-02	1.90E-02
2006	1.00E-03	1.00E-03	1.40E-02	8.00E-03	6.00E-03	9.00E-03	0.00E+00	0.00E+00	8.00E-03	8.00E-03	1.00E-02
Averages	7.17E-03	6.17E-03	2.47E-02	1.62E-02	2.60E-02	2.38E-02	2.72E-06	2.88E-05	1.30E-02	1.62E-02	1.65E-02

Given the above, it is reasonable to conclude that the effect of power uprate (approximate 13 percent increase) on gaseous radioactive effluents is negligible, and that continued compliance with the release limits of 10 CFR 20 and the design objectives of Appendix I to 10 CFR 50 is maintained with significant margin.

7.2 Radiation Levels and Offsite Dose

7.2.1 Operating and Shutdown In-Plant Radiation

The cycle annual average dose at Monticello has decreased at an approximate rate of 10 percent from cycle 18 to cycle 23. Extended power uprate will involve an increase in radiation levels.

MNGP was conservatively designed with respect to shielding and radiation sources. In the shielding analysis, the analytical assumptions for reactor water fission product concentrations and corrosion products are 8 μCi/cc and 0.07 μCi/cc respectively. The plant's administrative limit on total reactor water gamma activity for corrosion products is 0.5 μCi/ml. The gross alpha activity limit is 1E-6 μCi/ml. With expected operating increases in operating activity proportional to the proposed power increase, the design shielding assumptions remain bounding with significant margin at extended power uprate conditions.

Table 7.2.1-1, below, summarizes the exposure history for MNGP from 1990 through 2006.

Table 7.2.1-1

Exposure History (in REM) from 2006 MNGP ALARA Report

	Operation	Refueling Outage	Total
1990	94	0	94
1991	94	371	465
1992	114	0	114
1993	66	429	496
1994	78	321	395
1995	44	0	44
1996	71	169	240
1997	106	0	106
1998	47	162	209
1999	70	0	70
2000	40	176	216
2001	55	166	221
2002	40	0	40
2003	49	120	169
2004	35	0	35
2005	26	149	175
2006	33	0	33

In general, radiation levels and dose rates are estimated to increase in proportion to the increase in power level (i.e., approximately 13%). Dose reduction programs will continue to address the increases in individual doses due to extended power uprate. The plant radiation protection program will be used to maintain individual doses consistent with ALARA policies and well below the established limits of 10 CFR 20. Routine plant radiation surveys required by the radiation protection program will identify increased radiation levels in accessible areas of the plant and radiation zone postings will be adjusted if necessary. Time within radiation areas is controlled under the radiation protection program. Administrative dose control limits are established well below regulatory criteria and provide significant margin to that allowed by regulatory dose limits. Administrative dose limits are not routinely exceeded under present power conditions.

7.2.2 Offsite Doses at Extended Power Uprate Conditions

For extended power uprate, normal operational gaseous activity levels may increase slightly. The increase in activity levels is generally proportional to the percentage increase in core thermal power. This slight increase does not affect the large margin to the offsite dose limits established by 10 CFR 20. Doses from liquid effluents are currently zero and are expected to remain zero under extended power uprate conditions.

The Monticello Technical Specifications implement the guidelines of 10 CFR 50 Appendix I which are well within the 10 CFR 20 limits.

Table 7.1.3-2, previous, contains the results of the dose assessment for 2001-2006. An increase of approximately 13 percent for extended power uprate operation remains a very small fraction of the reporting limits.

Table 7.2.2-1 and Figure 7.2.2-1 present the ambient gamma radiation data for MNGP for the years 1991-2006. The conclusion from that data is that no plant effect on ambient gamma radiation is indicated.

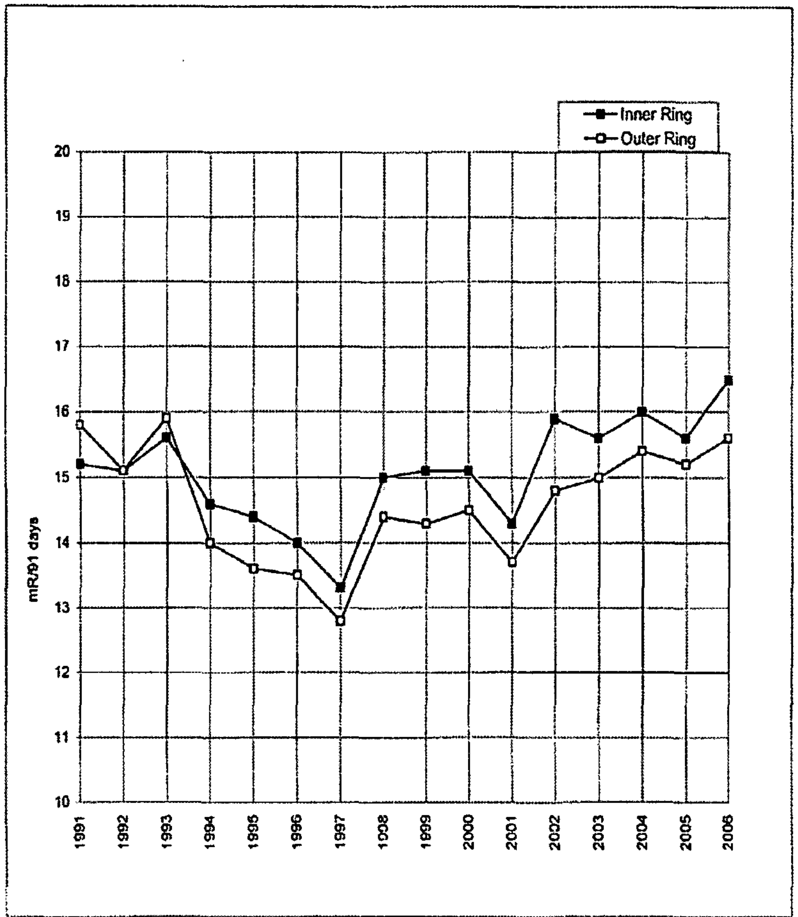
Table 7.2.2-1

Ambient Gamma Radiation as Measured by Thermoluminescent Dosimetry, Average Quarterly Dose Rates, Inner vs. Outer Ring Locations

	Inner Ring	Outer Ring
Year	Dose rate (mRem/qtr)	
1991	15.2	15.8
1992	15.1	15.1
1993	15.6	15.9
1994	14.6	14
1995	14.4	13.6
1996	14	13.5
1997	13.3	12.8
1998	15	14.4
1999	15.1	14.3
2000	15.1	14.5
2001	14.3	13.7
2002	15.9	14.8
2003	15.6	15
2004	16	15.4
2005	15.6	15.2
2006	16.5	15.6
Average	15.5125	14.8125

Figure 7.2.2-1

Ambient Gamma Radiation as Measured by Thermoluminescent Dosimetry, Average Quarterly Dose Rates, Inner vs. Outer Ring Locations



7.2.3 Ground Water Monitoring Program

NSPM implemented a ground water monitoring program as part of the Radiological Environmental Monitoring Program (REMP). Eight on-site monitoring wells are routinely sampled and analyzed to ensure that radioactive contamination is not impacting ground water. Reactor-produced contamination has not been identified in any ground water samples. Operation at EPU power levels is not expected to impact these results.

7.2.4 Radiation Levels and Offsite Doses - Conclusion

Extended power uprate does not involve significant increases in offsite dose from noble gases, airborne particulates, iodine, or tritium. Radioactive liquid effluents are not routinely discharged from MNGP. In addition, radiation from shine from extended power uprate conditions will have only a minimal impact on measured dose rates offsite.

Extended power uprate does not create any new or different sources of offsite dose from MNGP operation, and extended power uprate does not involve significant increases in present radiation levels. Therefore, it is reasonable to conclude that under extended power uprate conditions, offsite dose will remain well within regulatory criteria with no significant environmental impact.

7.3 Radiological Consequences of Accidents

Section VI of the Final Environmental Statement (FES) identifies nine classes of postulated accidents at MNGP that were evaluated by the NRC Staff to determine the associated environmental impact. "Accidents," in this context, includes those accidents evaluated for environmental consequences by the NRC Staff in addition to design basis accidents contained in the MNGP Final Safety Analysis Report (FSAR).

The NRC Staff used information provided by the Company in Section 10 and Appendix C of the MNGP Environmental Report (Ref. 1) to determine the associated environmental impacts. According to Section 3 of Ref. 1, the radiological effects determination is conducted utilizing reasonable assumptions, justifiable calculation models and techniques, and realistic assessments of environmental effects. The following discussion addresses the impact of extended power uprate on the assumptions and conclusions for the environmental accident classes. Comparisons are made, where applicable, with the accident analyses previously submitted by the Company in the MNGP Environmental Report. Note that MNGP has implemented the full-scope alternative source term methodology (Ref. 24). As such, comparisons are made for the events within the scope of that methodology.

7.3.1 Class 1 - Small Leaks Inside Containment

In accordance with AEC guidance for environmental reports at the time, Class 1 accidents were not considered within the scope. These accidents are initiated by small spills and leaks below the Technical Specification limits inside the primary containment or secondary containment. These leaks are bounded by those analyzed under Class 8 - LOCA Inside or Outside Containment. The NRC Staff considered that an incident of this type would cause releases that are commensurate with routine effluents (Section VI of Ref. 2). EPU evaluations regarding reactor coolant radiation sources indicate that total activity levels are less than 20 percent of the MNGP design basis for reactor water fission products and less than 50 percent of the MNGP design basis for activated corrosion products.

7.3.2 Class 2 - Miscellaneous Small Leaks Outside Containment

The postulated Class 2 accident is a continuous steam leak equivalent to a 7 gpm leak on the turbine building floor that releases through the turbine building roof vent. Extended power uprate does not increase the probability of occurrence or severity of this event. The turbine building vents were permanently secured subsequent to initial operation, and turbine exhaust air is processed through the reactor building ventilation system.

At extended power uprate conditions, the activity concentration of the reactor coolant will not increase above the assumptions used by the NRC Staff in the original analyses. These analyses assumed a coolant activity inventory of 0.2 μCi/cc to determine radiological effects (Section 10.b(2)(b) of Ref. 1). EPU evaluations regarding reactor coolant radiation sources indicate that total activity levels are less than 20 percent of the MNGP design basis for reactor water fission products and less than 50 percent of the MNGP design basis for activated corrosion products. Specifically, total fission product activity concentration in reactor water is 0.13 μCi/cc and the total non-coolant activation product activity concentration in reactor water is 0.029 μCi/cc at EPU conditions. Consequently, the dose conclusions of Table VI-2 of the FES for Class 2 accidents remain bounding for extended power uprate, and the radiological consequences of these accidents are not increased.

7.3.3 Class 3 - Radwaste System Failures

Class 3 accidents are included in Table VI-2 of the FES. Class 3.1 radwaste system failures are due to a single operator error or single equipment malfunction (Section 2.2 of Appendix C to Ref. 1). The Company selected two events to represent Class 3.1. These are 1) a liquid radwaste discharge-operator error, and 2) a gaseous waste discharge drain line failure. These accidents were chosen because these particular events were considered most probable (Section 7.0 of Appendix C to Ref. 1).

The NRC Staff included a Release of Waste Gas Storage Tank Contents Accident (Class 3.2) and a Release of Liquid Radwaste Storage Tank (Class 3.3) in Class 3. The Company analyzed these events as Class 8 accidents because of low probability (Sections 12.4 and Sections 12.5 of Appendix C to Ref. 1 respectively). These accidents will be addressed as Class 3 accidents herein to conform to the NRC Staff's determination.

ENCLOSURE 4

A. Class 3.1 Equipment Leakage or Malfunction

1. Liquid Radwaste Discharge

   Section 7.1 of Appendix C to the Environmental Report (Ref. 1) describes the assumptions used in postulating this event. The release is the result of an inadvertent pumping of the floor drain sample tank containing 0.7 Ci to the discharge canal for 20 minutes. The event is initiated by one of the following three single operator errors.

   The operator commences pumping without taking a batch sample.

   A batch sample is incorrectly analyzed prior to discharge.

   The operator pumps the wrong tank.

   From the above, it can be deduced that this accident was postulated because liquid radwaste discharges were expected to be performed routinely. However, evolutionary changes to the liquid radwaste system and changes in NSP's liquid radwaste discharge policies make this event extremely unlikely for current power and extended power uprate operating conditions. Liquid radwaste discharge is not routinely performed at MNGP. The plant is administratively operated as a zero radioactive liquid discharge plant. Operators have not discharged liquid radwaste to the canal for 35 years. Inadvertent pumping of liquid radwaste would require an implausible sequence of events involving multiple operator errors and malicious disregard for a variety of administrative controls. A procedure to pump liquid radwaste to the discharge canal, which does not currently exist and would likely be created for a one-time occurrence, would have to be developed and approved by a variety of environmental authorities. Operators are not authorized to perform evolutions without a valid procedure. The liquid radwaste discharge valve in the plant is a manual valve that is maintained shut. A sign at the valve warns the operator that management permission is required for operation. Additional manual valves in the discharge line are shut.

   The above accident is initiated by an operator error. The offsite dose consequences of a liquid radwaste equipment failure or operator error are bounded by a tank release. The radiological consequences of discharging the entire contents of the floor drain sample tank have been analyzed and found to be well within the limits of 10 CFR 50 Appendix I. See Section 7.3.3.C below.

   Given the above, the probability of this postulated environmental accident under extended power uprate conditions is significantly less than that assumed at initial licensing and would require multiple operator errors to occur.

2. Gaseous Radwaste Discharge

Section 7.2 of Appendix C to the Environmental Report (Ref. 1) describes the assumptions used in postulating this event. The release is the result of a loss of a drain line water seal. A modification to the Offgas System removed these water seals such that gaseous effluents are hard-piped and positively contained within closed drain tanks. Consequently, the probability of a malfunction of this type is significantly reduced at present and extended power uprate conditions because a release of this type would require a passive Offgas System pressure boundary failure instead of a single equipment failure.

Because of modifications made to the MNGP Offgas System since initial operation, it is difficult to directly analyze this postulated accident under extended power uprate conditions. These changes were described to the NRC Staff by several letters. See Section 2.1.1 of Ref. 13. For an updated system description, see Section 9.3 of the MNGP USAR (Ref. 7).

To the extent that a comparison can be made, the activity concentrations at extended power uprate are well bounded by the assumptions used in the original analyses. The original analyses assumed a normal offgas release rate of 25,000 μCi/sec whereas the EPU evaluation is indicating an average gaseous effluent release rate for the years 2001-2006 of 23.1 μCi/sec (which can be expected to increase proportionally to the EPU power increase, i.e., approximately 13 percent). Consequently, the dose conclusions of Table VI-2 of the FES for equipment failures remain bounding for extended power uprate, and the radiological consequences of this accident are not increased.

Gaseous waste discharges due to operator errors were not specifically analyzed by the Company in the original Environmental Report. Two MNGP technical specification limits incorporated after the issuance of the Final Environmental Statement address this issue. The offgas storage tank gross activity limit of 22,000 Ci (Xe-133 equivalent, MNGP Technical Specification 5.5.7) is based on limiting the offsite dose following an operator error that results in an inadvertent release of one decay tank after 12 hours of decay. A typical value for this parameter at current power levels is about eight (8) Ci. Extended power uprate will not involve significant increases in storage tank activity, and a large margin to the limit will be maintained. A separate technical specification limits the maximum activity at the steam jet air ejector (≤ 260 mCi/sec at 30 minutes, Technical Specification 3.7.6) to limit dose within regulatory criteria due to exposures from inadvertent discharges. From the discussion in the preceding paragraphs it is apparent that operation at extended power uprate will not involve significant increases in offgas activity above present levels, and significant margin to this limit will be maintained.

Gaseous waste accidents initiated by single operator errors or equipment failures are bounded by the multiple tank release analysis. See Section B below.

B. Class 3.2 Release of Waste Gas Storage Contents

Section 12.5 of Appendix C to Ref. 1 describes this accident. The accident is the result of a hydrogen ignition in the holdup volume. The probability of this accident is significantly less likely since NSP has installed offgas recombiners in the Air Ejector Offgas System. See Section 9.3.3.4, Hydrogen Explosion, of the MNGP USAR (Ref. 7) for a description and analysis.

The hydrogen handling design of the augmented offgas system has been reviewed and approved by the NRC Staff (Ref. 15). The offgas system is designed to withstand the pressure from a hydrogen detonation. Loss of dilution steam results in a recombiner train shutdown. In addition, hydrogen is monitored, and automatic shutdowns occur well before potentially explosive hydrogen concentrations are reached. An explosion in the recombiner could cause a release via the recombiner's hydrogen analyzer equipment. This release has been analyzed and was found to be within limits. The analyzer release is bounded by the multiple tank failure accident described below.

The Offgas System has been designed to prevent an explosive mixture from propagating beyond the recombiner system. In 1973, the NRC Staff evaluated the effects of an offgas tank failure for the augmented offgas system. By Section 6.1 of the safety evaluation for the full term operating license (Ref. 13), the NRC Staff analyzed the radiological consequences of a simultaneous failure of five offgas storage tanks. The offgas release rate was assumed to be equivalent to the prevailing Technical Specification limits. The NRC Staff concluded that the dose at the site boundary was well within the values given in 10 CFR 100. This conclusion remains valid under extended power uprate conditions. Extended power uprate will not increase the probability of this accident and will not involve operation above the release rates assumed by the NRC Staff, and consequently, the previously analyzed dose rates continue to bound operation at extended power uprate conditions.

C. Class 3.3 Release of Liquid Waste Storage Tank Contents

This accident involves a catastrophic failure of a low level radwaste tank which included a simultaneous failure of the tank's containment basin (Section 12.4 of Appendix C to Ref. 1). The activity was released to the discharge canal. The analysis assumed a total radwaste tank activity content based on the prevailing technical specification limits.

Technical specification inventory limits are provided for undiked temporary radwaste tanks. The technical specification limit for undiked temporary tanks is 10 Ci, excluding tritium and dissolved or entrained noble gases. Extended power uprate will not, of itself, involve storage of low level radwaste outside of the radwaste building. If storage does occur, the temporary tank radioactivity limit of Technical Specification 5.5.7 will not be exceeded.

Concerning installed radwaste tanks, the Company analyzed radwaste tank discharges by its Appendix I filing (Section 1.1 of Ref. 16). In this analysis it was assumed that the entire contents of the floor drain sample tank after treatment was discharged to the Circulating Water System with no credit for Mississippi River dilution. Conservative discharges of chemical wastes and laundry wastes were also assumed. Exposures were calculated using the guidance of Regulatory Guide 1.109. The resultant doses were well below the 10 CFR 50 Appendix I limits. Extended power uprate will not have a material impact on the effectiveness of the liquid waste processing system or on the generation and activity level of liquid wastes at MNGP. Consequently, the results of the Appendix I radwaste tank discharge analysis are bounding for extended power uprate conditions.

7.3.4 Class 4 - Events that Release Radioactivity into Primary System

According to Section 2.2 of Appendix C to the Environmental Report (Ref. 1), no Class 4 events were identified for MNGP. Table VI-2 of the FES includes dose estimates for Class 4 events. The assumptions for these dose estimates could not be located. It is reasonable to conclude, however, that these estimates will remain bounding for extended power uprate. According to Table VI-2, Class 4 events include releases due to fuel cladding defects and releases from fuel failures induced from transients. Fuel cladding defects have been significantly reduced since initial operation due to industry improvements. In addition, operational limits are calculated at MNGP for each cycle to prevent transients from inducing fuel damage. These limits involve significant margin to fuel failure. These calculations will continue to be performed, and the appropriate limits will continue to be imposed under extended power uprate conditions.

7.3.5 Class 5 - Events that Release Radioactivity into Secondary System

Class 5 accidents were intended to apply to Pressurized Water Reactors (PWRs). A justification for not including Class 5 accidents was presented in Section 9 of Appendix C of Reference 1. Extended power uprate does not impact this justification.

7.3.6 Class 6 - Refueling Accidents Inside Containment

Class 6 accidents include refueling and fuel handling accidents. The Company chose the design basis refueling accident and a spent fuel cask drop to represent this class. The refueling accident is specifically addressed in the design basis accident section below (Class 8). The following discussion addresses the spent fuel cask drop and fuel damage from heavy loads.

The spent fuel cask drop was analyzed in Section 10.2 of Appendix C to Ref. 1. A cask was assumed to drop from a crane while being lowered to a flatcar. Because of cask design integrity and fuel capability, no fuel damage was postulated. A 1000 Ci release was assumed in accordance with 10 CFR 71 criteria.

Since initial licensing the cask drop accident has been re-evaluated by the Company at the request of the NRC Staff, in part to support actual fuel shipments made from MNGP. These evaluations resulted in a variety of design and administrative improvements in cask handling. By its review of cask handling at MNGP in May 1977 (Ref. 9), the NRC Staff concluded that, "the licensee has proposed adequate measures to preclude the occurrence of a cask drop accident and to mitigate its effect in the very unlikely event that it should occur."

Subsequent to this action, the NRC Staff issued generic letters that requested that licensees determine the extent of compliance with NUREG-0612. The safety concerns of a heavy object drop at MNGP are mitigated by compliance with NUREG-0612. The crane system for lifting casks at MNGP is designed for single failures. Procedural controls and safe load paths are in place to prevent handling of heavy objects above the core and the fuel pool. By SER dated March 19, 1984 (Ref. 10), the NRC Staff concluded that the guidelines of Section 5.1.1 and 5.1.3 of NUREG-0612 had been satisfied. For additional information on cask movement and crane safety at MNGP, see the Company's response to NRC Bulletin 96-02, Movement of Heavy Loads Over Spent Fuel, Over Fuel in the Reactor Core, Or Over Safety Related Equipment (Ref. 14).

Notwithstanding the Company's stated compliance with NUREG-0612, the severity of any heavy load drop involving fuel damage is less at extended power uprate conditions. The FES analysis was based on the fractional activity of 7x7 fuel assemblies. The Company has replaced all the 7x7 fuel at MNGP with 8x8, 9x9, or 10X10 fuel. The effect of this change in fuel design was to lower the fuel pin centerline temperature, which lowered the release of fission product gases from the fuel. This, in turn, lowered the available inventory of gases in the fuel pin cladding gap available for release to the environment. According to Section 14.7.6.3.1 of the MNGP USAR, the relative amount of activity released for 9X9 array fuel is 0.91 times the activity released for a core of 8X8 fuel. Similarly, the relative amount of activity released for 10X10 array fuel is 0.95 times the activity released for a core of 8X8 fuel. Therefore, for those accidents that assume fuel cladding failures caused by a heavy object drop, the radioactivity available for release and the subsequent magnitude of the release to the environment is still bounded by that previously analyzed in the FES.

7.3.7 Class 7 - Accidents to Spent Fuel Outside Containment

Extended power uprate does not significantly impact the probability or consequences of a transportation accident. NSPM has evaluated the conditions and assumptions of Table S-4 of 10 CFR 51.52 for MNGP operation at extended power uprate conditions. These conditions and assumptions are applicable for MNGP operation under extended power uprate conditions. Table S-4 of 10 CFR 51.52 presents a generic evaluation of the environmental impact of fuel and waste transportation accidents. See Section 8.2 below for additional information.

7.3.8 Class 8 - Accident Initiation Events Considered in the Design Basis Evaluation in the SAR

The environmental impact analysis made in the FES for Class 8 accidents was based on information provided by the Company in its Environmental Report (Section II of Ref. 1). These accidents included the Recirculation Line Suction Break, the Main Steam Line Break, and the Control Rod Drop Accident. The radwaste tank failure and the offgas accident, which were originally analyzed as Class 8, are evaluated in Section 7.3.3 above. The design basis refueling accident, which was originally analyzed as Class 6, is included in the Class 8 evaluation.

The methodology used to determine the offsite doses for environmental impacts of Class 8 was based in part on subjective and realistic assumptions, and the FES results were expressed in estimated fractions of 10 CFR 20. It is difficult to recreate this methodology, and the value of recreating it is questionable in light of some non-conservatisms such as the assumed availability of offsite power and because of evolutionary changes in dose calculations. Therefore, for extended power uprate, a comparison is presented between the original full-scope implementation of the alternative source term methodology (Ref. 24) and the same methodology at EPU conditions.

Table 7.3.8-1 summarizes the accident analysis results (Note: The dose values for the 1880 MWth column are consistent with what was developed for the Alternate Source Term amendment, Ref. 24):

ENCLOSURE 4

Table 7.3.8-1 Accident Analysis Results

Parameter	1880 MWth (Current Licensed Thermal Power Level Design Assumption Value)	2004 MWth (Extended Power Uprate Value)	Regulatory Limit (10 CFR 50.67) & (10 CFR 50, App. A, GDC 19)
Post-LOCA Accident Dose:			
EAB	1.31 Rem TEDE	1.46 Rem TEDE	25 Rem TEDE
LPZ	1.72 Rem TEDE	1.99 Rem TEDE	25 Rem TEDE
CR Operator	3.40 Rem TEDE	3.80 Rem TEDE	5 Rem TEDE
TSC Operator	0.77 Rem TEDE	0.83 Rem TEDE	5 Rem TEDE
FHA Accident Dose:			
EAB	1.61 Rem TEDE	1.74 Rem TEDE	6.25 Rem TEDE
LPZ	0.31 Rem TEDE	0.34 Rem TEDE	6.25 Rem TEDE
CR Operator	4.29 Rem TEDE	4.67 Rem TEDE	5 Rem TEDE
CRDA Accident Dose:			
EAB	1.73 Rem TEDE	1.96 Rem TEDE	6.25 Rem TEDE
LPZ	0.79 Rem TEDE	0.90 Rem TEDE	6.25 Rem TEDE
CR Operator	1.70 Rem TEDE	1.86 Rem TEDE	5 Rem TEDE
MSLBA Accident Dose: Pre-Incident Iodine Spike			
EAB	1.05 Rem TEDE	1.05 Rem TEDE	25 Rem TEDE
LPZ	0.20 Rem TEDE	0.20 Rem TEDE	25 Rem TEDE
CR Operator	3.25 Rem TEDE	3.25 Rem TEDE	5 Rem TEDE
MSLBA Accident Dose: Equilibrium Iodine Conc.			
EAB	0.11 Rem TEDE	0.11 Rem TEDE	2.5 Rem TEDE
LPZ	0.02 Rem TEDE	0.02 Rem TEDE	2.5 Rem TEDE
CR Operator	0.33 Rem TEDE	0.33 Rem TEDE	5 Rem TEDE

Given the above, the radiological consequences of design basis accidents under extended power uprate conditions are within the acceptance criteria of GDC 19 of Appendix A to 10 CFR 50, 10 CFR 50.67, and RG 1.183 and do not involve any significant impact to the human environment.

7.3.9 Class 9 - Severe Accidents

The environmental effects of severe accidents outside the design basis of protection and engineered safety systems were not evaluated in the MNGP FES. (See Section VI.A of Ref. 2.) The NRC Staff did not evaluate these sequences on the premise that sufficient design conservatism, quality assurance, testing, and multiple physical barriers were in place such that the probability of a severe environmental accident is small, and the environmental risk of a Class 9 accident was extremely low. Extended power uprate will not involve any changes to the NRC Staff's assumptions made in arriving at the above conclusion.

Notwithstanding the above, NMC (now NSPM) conducted an evaluation (Ref. 31) to identify the risk implications due to EPU at MNGP. The scope included the complete risk contribution associated with the EPU. Risk impacts due to internal events were assessed using the MNGP Level 1 and Level 2 PRA Model of Record. External events were evaluated using the analyses of the MNGP Individual Plant Examination of External Events (IPEEE) submittal (Ref. 30). The results indicate that the risk impact due to EPU is low and acceptable. The risk impact is in the "very low" category (i.e., Region III of the Regulatory Guide 1.174 Guidelines) for core damage frequency (CDF) and large early release frequency (LERF).

7.4 Other Potential Environmental Accidents

Extended power uprate does not significantly change the inventory, storage, usage, or control requirements for chemicals, industrial gases, oil, oil products, or other hazardous substances. Extended power uprate will not require the introduction or use of any new hazardous substances. Extended power uprate will not result in a significant increase in the probability or consequences of an oil spill, chemical spill, industrial gas release, or other event involving a non-radioactive hazardous substance.

8.0 ENVIRONMENTAL EFFECTS OF URANIUM FUEL CYCLE ACTIVITIES AND FUEL AND RADIOACTIVE WASTE TRANSPORTATION

8.1 Compliance With 10 CFR 51.51, Uranium Fuel Cycle Environmental Data (Table S-3)

Table S-3 of 10 CFR 51.51 was adopted after MNGP received its operating license, therefore, the MNGP FES does not contain a uranium fuel cycle environmental analysis similar to Table S-3. The NRC Staff, however, included the Table S-3 fuel cycle environmental data in its review of the MNGP full term operating license (Enclosure 3 of Ref. 12) and the renewed operating license (Ref. 19). The NRC Staff concluded that the fuel cycle effects of Table S-3 combined with operation of MNGP did not significantly impact the environment. The impact of extended power uprate on the NRC Staff's previous evaluation is increased fuel burnup and U-235 enrichment.

The environmental effects of fuel cycle activities under extended power uprate conditions continue to be bounded by the NRC Staff's evaluation that incorporated Table S-3 into the MNGP licensing basis as described above. The evaluation assumed that the fuel cycle would support a reference reactor of 1000 MWe that operated at 80 percent capacity factor which results in an adjusted daily electricity production of 800 MWe during a reference reactor year (RRY). Under extended power uprate conditions the daily output at 100 percent capacity is less than 700 MWe and MNGP will not exceed the assumptions of the RRY used in the evaluation.

The data presented in Tables S-3 and S-4 are, in part, based on an average burnup assumption of 33,000 MWd/MtU and a U-235 enrichment assumption of 4 wt.percent. Fuel consumption is expected to increase under extended power uprate conditions such that the batch average burnup of the fuel assemblies will be in excess of 33,000 MWd/MtU but less than 60,000 MWd/MtU (MNGP EPU evaluation indicates a maximum assembly exposure of approximately 53,000 MWd/MtU). The U-235 enrichments levels will also increase to greater than 4 wt.percent but less than 5 wt.percent to support extended burnup. The NRC Staff has previously evaluated the environmental impact of increased burnup to 60,000 MWd/MtU with U-235 fuel enrichment to 5 wt.percent on the conclusions of Table S-3. See the GEIS for license renewal (Refs 5, 19 & 20). Although some radionuclide inventory levels and activity levels are projected to increase, the NRC Staff noted that little or no increase in the amount of radionuclides released to the environment during normal operation was expected. The NRC Staff determined that the incremental environmental effects of increased enrichment and burnup on transportation of fuel, spent fuel, and waste were not significant. In addition, the NRC Staff recognized the salient environmental benefits of extended burnup such as reduced occupational dose, reduced public dose, reduced fuel requirements per unit electricity, and reduced shipments. The NRC Staff concluded that the environmental impacts described by Table S-3 were bounding and were also applicable for burnup levels to 60,000 MWd/MtU and U-235 enrichment levels to 5 wt.percent.

Table S-3 does not include a determination of the environmental effects of the gaseous effluents of Rn-222 and Tc-99. By Enclosure 3 to the issuance of the MNGP full term operating license (Ref. 12) and the license renewal (Ref. 19), the NRC Staff evaluated these effluents and concluded that the environmental impact from radon releases was not significant. In addition, an industry study performed by the Atomic Industry Forum (Ref. 11) concluded that extending fuel burnup to 60,000 MWd/MtU and increasing U-235 enrichment to 5 wt.percent results in insignificant environmental consequences from Rn-222 and Tc-99.

8.2 Compliance With 10 CFR 51.52, Environmental Effects of Transportation of Fuel and Waste (Table S-4)

The environmental impacts of transporting fuel and waste were analyzed by the NRC Staff in the FES and the license renewal environmental impact statement (Ref. 19). 10 CFR 51.52, Table S-4 presents a generic assessment of the environmental impacts of transporting fuel and waste to and from a reference reactor. For extended power uprate operating conditions, this demonstration supersedes the previous Company submittals concerning environmental effects of transportation of fuel and waste including Sections 11.0 of 13.0 of Appendix C to the Environmental Report (Ref. 1).

Operation of MNGP under extended power uprate conditions meets all the conditions of part (a) of 10 CFR 51.52 with the exception of the enrichment and burnup conditions as described in the succeeding paragraphs. Each subsection of part (a) is addressed below for extended power uprate conditions. The enrichment assumptions of paragraph (a)(2) and the burnup assumptions of paragraph (a)(3) are addressed separately below.

(a)(1) The core thermal power under extended power uprate conditions is less than 3800 MW.

(a)(2) The reactor fuel is in the form of sintered uranium dioxide pellets, and the pellets are encapsulated in zircalloy rods.

(a)(3) No irradiated fuel assembly is shipped until at least 90 days after it is discharged from the reactor.

(a)(4) With the exception of irradiated fuel, all radioactive waste shipped from the reactor is packaged and in a solid form.

(a)(5) Unirradiated fuel is shipped by truck; irradiated fuel is shipped by truck, rail, or barge; and radioactive waste other than irradiated fuel is shipped from the reactor by truck or rail.

(a)(6) In accordance with paragraph (a)(6) of 10 CFR 51.52, the environmental impacts of transportation of fuel and waste to and from the reactor at extended power uprate conditions with respect to normal and accident conditions of transport are as set forth in Table S-4 with the exception of fuel enrichment and burnup assumptions. The values in the table represent the contribution of the transportation to the environmental costs of operating at extended power uprate conditions.

NSPM complies with the conditions of Table S-4 for the MNGP extended power uprate except for the U-235 enrichment and fuel burnup assumptions. The conservatism and continued applicability of Table S-4, however, has been previously evaluated by the NRC Staff for enrichment to 5 wt. percent and for average burnup to 62,000 MWd/MtU (Ref. 19).

9.0 DECOMMISSIONING EFFECTS

Other than financial set asides, the environmental effects of decommissioning were not evaluated by the NRC Staff in the Monticello FES (Section XIII, Question 45, and Section VIII.C of Ref. 2). The AEC deferred this review until the submittal of a decommissioning plan. The Company's decommissioning plan for Monticello will be submitted in accordance with regulatory criteria. Extended power uprate does not involve any substantial increases in decommissioning cost estimates and does not affect the Company's ability to maintain sufficient financial reserves for decommissioning.

The potential impact of extended power uprate on decommissioning is due to increases in feedwater flow rate and increased neutron fluence. These effects could increase the amount of activated corrosion products and consequently increase post-shutdown radiation levels.

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10.0 CONCLUSIONS

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 1670 MWth in the Summary and Conclusions Section of the Final Environmental Statement (Ref. 2) 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 effect of extended power uprate on the environment does not prevent continued compliance with any MNGP environmental permit. None of the license conditions for environmental protection will be changed for extended power uprate. No effluent limits will be exceeded, and the present large margins to these limits will not be significantly changed. Extended power uprate does not involve an increase in the discharge of hazardous substances, contaminants, or pollutants and does not involve the use of any new hazardous substances, contaminants, or pollutants.

Extended power uprate does not involve any changes to air quality or water quality. It does not result in any changes to land usage and has an insignificant effect on groundwater and surface water usage. The amount of water withdrawn and consumed from the Mississippi River is not significantly increased above that previously evaluated. The slight increase in discharge canal temperature has an insignificant effect on river temperature and will not result in any changes to aquatic biota other than those previously evaluated. Extended power uprate will not involve new or different discharges of contaminants and does not involve changes to any bioaccumulation effects for aquatic organisms. Extended power uprate does not accelerate the introduction of any microbiological organisms into surface water pathways or significantly increase the population of any known pathogens.

Extended power uprate does not involve any changes to wildlife habitat and does not result in any significant changes to aquatic or terrestrial biota. There are no deleterious effects on the diversity of biological systems or the sustainability of species due to extended power uprate. Extended power uprate does not involve any additional changes to the stability and integrity of ecosystems. Extended power uprate does not affect the previous conclusions on impingement or entrainment. Extended power uprate does not affect NSPM's compliance with Sections 316(a) or 316(b) of the Federal Water Pollution Control Act.

Extended power uprate does not significantly change any doses to the public from radiological effluents, and offsite doses will continue to be well within regulatory limits. By Section 2.1.3 of the Safety Evaluation for the MNGP full term operating license, the NRC Staff concluded that "the release of radioactive material in liquid and gaseous effluents from the Monticello Nuclear Generating Plant will meet the requirements of 10 CFR 50 for keeping such effluent levels to unrestricted areas as low as practicable and will result in doses that are a small percentage of the 10 CFR 20 limits." The NRC Staff based this conclusion on assumptions for effluent releases that bound releases expected for extended power uprate. Occupational dose will be maintained well within regulatory limits, and changes in radiation levels will not significantly increase the dose to the MNGP work force. For accident dose, the methodology for certain design basis accidents was updated. This methodology is consistent with previously approved NRC Staff methods, and the resultant dose is well within the applicable regulatory limits. Extended power uprate does not involve significant increases in the probability or consequences of previously evaluated environmental accidents.

This environmental evaluation has demonstrated that in most cases extended power uprate does not involve any environmental impacts that are different from those previously evaluated for the present power level. Where environmental impacts which differ from those previously evaluated have been identified, these impacts have been shown to be insignificant and well within regulatory environmental acceptance criteria.

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11.0 REFERENCES

1. Northern States Power Company, Environmental Report, Monticello Nuclear Generating Plant, November 5, 1971

2. Final Environmental Statement Related to Operation of Monticello Nuclear Generating Plant Northern States Power Company Docket No. 50-263, United States Atomic Energy Commission Directorate of Licensing, November 1972

3. Northern States Power Company Environmental Report Supplement 1, Monticello Nuclear Generating Plant, April 4, 1972

4. "Section 316(b) Demonstration for the Monticello Nuclear Generating Plant on the Mississippi River at Monticello, Minnesota," NUS Corporation, Ecological Sciences Division, Pittsburgh, Pennsylvania, 1978

5. NUREG-1437, Vol. I, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," U.S. NRC Office of Nuclear Regulatory Research, May 1996

6. "Effects of a Heated Discharge on the Ecology of the Mississippi River: 316(a) Type 1 Demonstration on the Monticello Nuclear Generating Plant, Monticello, Minnesota," NUS Corporation, Ecological Sciences Division, Pittsburgh, Pennsylvania, 1975

7. MNGP Updated Safety Analysis Report, Rev. 24

8. "EMF Electric and Magnetic Fields Associated with the Use of Electric Power," June 2002, Prepared by the National Institute of Environmental Health Sciences and National Institutes of Health, Sponsored by the NIEHS/DOE EMF Rapid Program.

9. Letter from D. K. Davis, NRC, to L. O. Mayer, NSP, May 19, 1977

10. Letter from D. B. Vassallo, NRC, to D. M. Musolf, NSP, "Control of Heavy Loads (Phase I)," March 19, 1984

11. "The Environmental Consequences of Higher Fuel Burn-up," AIF/NESP-032, Atomic Industrial Forum, June 1985

12. Letter from D. G. Eisenhut, NRC, to L. O. Mayer, NSP, Issuance of Full Term Operating License DPR-22, January 9, 1981

13. Safety Evaluation By The Directorate Of Licensing U.S. Atomic Energy Commission For Northern States Power Company Monticello Nuclear Generating Plant Unit No. 1 Full Term Operating License, February 5, 1973

14. Letter from W. J. Hill, NSP, to NRC Document Control Desk, "Response to NRC Bulletin 96-02 Movement of Heavy Loads Over Spent Fuel, Over Fuel in the Reactor Core, Or Over Safety Related Equipment," May 8, 1996

15. Monticello Nuclear Generating Plant, "Answers to DRL Questions of June 3, 1971," October 1971

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16. Letter from L. O. Mayer, to D. L. Ziemann, NRC, "Appendix I Filing Supplement 1," July 21, 1976

17. Letter from T. Kim, NRC, to R. Anderson, NSP, "Environmental Assessment and Final Finding of No Significant Impact – Monticello Nuclear Generating Plant," August 27, 1998

18. Letter from T. Kim, NRC, to R. Anderson, NSP, "Monticello Nuclear Generating Plant – Issuance of Amendment RE: Power Uprate Program," September 16, 1998

19 NUREG-1437, Supplement 26, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants, Supplement 26, Regarding Monticello Nuclear Generating Plant, Final Report," August 2006

20 NUREG-1437, Volume 1, Addendum 1, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants," Final Report, August 1999

21 2007 Resource Plan, Xcel Energy, December 14, 2007, J. Poferl (Xcel Energy) to B. Haar (Minnesota Public Utilities Commission), Docket No. E002/RP-07-1572

22. Federal Register Notice, 7/9/07, Part III Department of the Interior, Fish and Wildlife Service, 50CFR Part 17, Volume 72, No. 130, 37346-37372)

23. MNGP Environmental Monitoring Program, 2006-2007 Report, prepared by Xcel Energy Environmental Services

24. Letter from P. Tam, NRC, to J. Conway, NMC, "Monticello Nuclear Generating Plant – Issuance of Amendment RE: Full-Scope Implementation of the Alternative Source Term Methodology (TAC NO. MC8971)," December 7, 2006 (ADAMS ML062850049)

25. Minnesota's Federally Listed Threatened, Endangered, Proposed, and Candidate Species' County Distribution, December 2007

26. Higgins' Eye (PearlyMussel) Information, http://ecos.fws.gov/docs/life_histories/F009.html

27. Applicant's Environmental Report – Operating License Renewal Stage, MNGP, NMC, March 2005

28. U.S. Fish and Wildlife Service, Threatened and Endangered Species System (TESS), Minnesota Federal Listed and Candidate species, online query February 14, 2008

29. Memorandum from T. Palmisano, NMC to D. Stinnett, U.S. Fish and Wildlife Service, March 2, 2005, Table 2 "Threatened and Endangered Species Occurring in the Vicinity of MNGP and the Associated Transmission Corridors"

30. MNGP, "Monticello Nuclear Plant Individual Plant Examination for External Events (IPEEE) Submittal," November 1995

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31. "Identification of Risk Implications Due to Extended Power Uprate at Monticello," ERIN Engineering and Research , Inc., March 2008, Final

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ATTACHMENT A

MONTICELLO NUCLEAR GENERATING PLANT—EXTENDED POWER UPRATE

ENVIRONMENTAL AUTHORIZATIONS FOR CURRENT OPERATIONS/ PERMIT RENEWAL SCHEDULE

Agency	Authority	Requirement	Number	Expiration Date	Renewal Frequency
Minnesota Department of Natural Resources[a]	Minnesota Statutes Chapter 103G.271	Water Appropriations Permit	67-0083	NA	Does not expire
Minnesota Department of Natural Resources[a]	Minnesota Statutes Chapter 103G.271	Water Appropriations Permit	66-1172	NA	Does not expire
Minnesota Department of Natural Resources	Minnesota Statutes Chapter 97A.401	Division of Fish and Wildlife Special Permit	14658	12/31/08	Yearly renewal
Minnesota Department of Natural Resources	Minnesota Statutes Chapter 97A.401	Division of Ecological Services Special Permit REMP mussel collection	12683	12/31/08	5-year renewal
Minnesota Pollution Control Agency	Minnesota Statutes Chapters 115 and 116	National Pollutant Discharge Elimination System (NPDES) Permit	MN0000868	9/30/12	5-year renewal
Minnesota Pollution Control Agency	Minnesota Statutes Chapters 115 and 116	NPDES (General Stormwater Permit for Industrial Activity)	MN G610000	9/30/12	Incorporated in the NPDES Permit during 2007 renewal process
Minnesota Pollution Control Agency	Minnesota Rules Chapter 7045.0225	Hazardous Waste Generator License	MND000686139	06/30/08	Yearly renewal

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Agency	Authority	Requirement	Number	Expiration Date	Renewal Frequency
Minnesota Pollution Control Agency	Minnesota Rules Chapters 7007.0150	Air Emission Permit	17100019-003	08/16/05	5-year renewal (permit renewal submitted 2/17/05 and remains in-process)[1]
City of Monticello	City of Monticello Ordinance Title 14, Chapter 4	Sanitary Sewer Wastewater Discharge Agreement	001	NA	Does not expire
Minnesota Pollution Control Agency	Minnesota Statutes Chapters 115 and 116	NPDES (State Disposal System (SDS) Permit)	MN0058343	9/30/12	Incorporated in the NPDES Permit during 2007 renewal process
Minnesota Department of Natural Resources	Minnesota Statues Chapter 103G.315 Minnesota Rule Chapter 6115.0200	"Work In Waters" Permit (State Dredging Permit)	67-0743	NA[b]	Does not expire; maintenance provision #8 requires written approval for each project
State of Tennessee Department of Environment and Conservation	TDEC 1200-2-10-.30	Radioactive Shipment License	T-MN002-L08	12/31/08	Yearly renewal
South Carolina Department of Health and Environmental Control	South Carolina ADC 61-83	South Carolina Radioactive Waste Transport Permit	0026-22-06	12/31/08	Yearly renewal
Utah Department of Environmental Quality	Utah Code Annotated, Title 19 Chapter 3; UAC R313-21	Generator Site Access Permit	0209 001 562	09/10/08	Yearly renewal

[1] Minnesota Rule 7007.0450, Subpart 3, "Continuation of an expiring permit," defines the conditions under which an existing permit does not expire pending reissuance of the permit.

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Agency	Authority	Requirement	Number	Expiration Date	Renewal Frequency
U.S. Army Corps of Engineers	Section 10 of the Rivers and Harbors Act of 1899; Section 404 of the Clean Water Act	"Work In Waters Permit"	01-02982-GP-GAE; coverage under Department of Army General Permit GP-001-MN	NA[b]	Not applicable; secure determination with each project on the river bed
U.S. Department of Transportation	49 USC 5108 (49 CFR 107.601)	Certificate of Registration for Transportation of Hazardous Materials	062707550034P	6/30/08	Yearly renewal
U.S. Fish and Wildlife Service	16 USC 703-712 (50 CFR Part 13 and 50 CFR 21.27)	Special Purpose Permit	MB074020-0	03/31/09	Three-year permit renewal cycle
U.S. Nuclear Regulatory Commission	Atomic Energy Act (42 USC 2011 et seq.), 10 CFR 50.10	Facility Operating License	Unit 1 – DPR-22	09/08/30	Forty-year original term; 20-year license renewal approved

a. Original permit issued by Minnesota Department of Conservation in 1970. The Department of Conservation was renamed Minnesota Department of Natural Resources in 1971.

b. Expiration date not applicable for the master permit. In addition, there are no actions currently authorized.

CFR = Code of Federal Regulations

NA = Not Applicable

TDEC = Tennessee Department of Environment and Conservation

U.S. = United States

USC = United States Code

Enclosure 6 to L-MT-08-052

GE Hitachi Affidavit

GE-Hitachi Nuclear Energy Americas LLC

AFFIDAVIT

I, Tim E. Abney, state as follows:

(1) I am Vice President, Services Licensing, Regulatory Affairs, GE-Hitachi Nuclear Energy Americas LLC ("GEH"). I have been delegated the function of reviewing the information described in paragraph (2) which is sought to be withheld, and have been authorized to apply for its withholding.

(2) The information sought to be withheld is contained in GEH Licensing Topical Report NEDC-33322P, "Safety Analysis Report for Monticello Constant Pressure Power Uprate", Revision 3, Class III (GEH Proprietary Information), October 2008. GEH proprietary information text in NEDC-33322P Revision 3 is identified by a dark red dotted underline inside double square brackets [[This sentence is an example.{3}]]. Figures and large equation objects containing GEH proprietary information are identified with double square brackets before and after the object. In each case, the superscript notation {3} refers to Paragraph (3) of this affidavit, which provides the basis for the proprietary determination.

(3) In making this application for withholding of proprietary information of which it is the owner or licensee, GEH relies upon the exemption from disclosure set forth in the Freedom of Information Act ("FOIA"), 5 USC Sec. 552(b)(4), and the Trade Secrets Act, 18 USC Sec. 1905, and NRC regulations 10 CFR 9.17(a)(4), and 2.390(a)(4) for "trade secrets" (Exemption 4). The material for which exemption from disclosure is here sought also qualify under the narrower definition of "trade secret", within the meanings assigned to those terms for purposes of FOIA Exemption 4 in, respectively, Critical Mass Energy Project v. Nuclear Regulatory Commission, 975F2d871 (DC Cir. 1992), and Public Citizen Health Research Group v. FDA, 704F2d1280 (DC Cir. 1983).

(4) Some examples of categories of information which fit into the definition of proprietary information are:

a. Information that discloses a process, method, or apparatus, including supporting data and analyses, where prevention of its use by GEH's competitors without license from GEH constitutes a competitive economic advantage over other companies;

b. Information which, if used by a competitor, would reduce his expenditure of resources or improve his competitive position in the design, manufacture, shipment, installation, assurance of quality, or licensing of a similar product;

c. Information which reveals aspects of past, present, or future GEH customer-funded development plans and programs, resulting in potential products to GEH;

d. Information which discloses patentable subject matter for which it may be desirable to obtain patent protection.

The information sought to be withheld is considered to be proprietary for the reasons set forth in paragraphs (4)a. and (4)b. above.

(5) To address 10 CFR 2.390(b)(4), the information sought to be withheld is being submitted to NRC in confidence. The information is of a sort customarily held in confidence by GEH, and is in fact so held. The information sought to be withheld has, to the best of my knowledge and belief, consistently been held in confidence by GEH, no public disclosure has been made, and it is not available in public sources. All disclosures to third parties, including any required transmittals to NRC, have been made, or must be made, pursuant to regulatory provisions or proprietary agreements which provide for maintenance of the information in confidence. Its initial designation as proprietary information, and the subsequent steps taken to prevent its unauthorized disclosure, are as set forth in paragraphs (6) and (7) following.

(6) Initial approval of proprietary treatment of a document is made by the manager of the originating component, the person most likely to be acquainted with the value and sensitivity of the information in relation to industry knowledge, or subject to the terms under which it was licensed to GEH. Access to such documents within GEH is limited on a "need to know" basis.

(7) The procedure for approval of external release of such a document typically requires review by the staff manager, project manager, principal scientist, or other equivalent authority for technical content, competitive effect, and determination of the accuracy of the proprietary designation. Disclosures outside GEH are limited to regulatory bodies, customers, and potential customers, and their agents, suppliers, and licensees, and others with a legitimate need for the information, and then only in accordance with appropriate regulatory provisions or proprietary agreements.

(8) The information identified in paragraph (2) above is classified as proprietary because it contains detailed results and conclusions regarding supporting evaluations of the safety-significant changes necessary to demonstrate the regulatory acceptability of the "Safety Analysis Report for Monticello Constant Pressure Power Uprate" for a GEH Boiling Water Reactor ("BWR"). The analysis utilized analytical models and methods, including computer codes, which GEH has developed, obtained NRC approval of, and applied to perform evaluations of Constant Pressure Power Uprate analysis for a GEH BWR.

The development of the evaluation process along with the interpretation and application of the analytical results is derived from the extensive experience database that constitutes a major GEH asset.

(9) Public disclosure of the information sought to be withheld is likely to cause substantial harm to GEH's competitive position and foreclose or reduce the availability of profit-making opportunities. The information is part of GEH's comprehensive BWR safety and technology base, and its commercial value extends beyond the original development cost. The value of the technology base goes beyond the extensive physical database and analytical methodology and includes development of the expertise to determine and apply the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

The research, development, engineering, analytical and NRC review costs comprise a substantial investment of time and money by GEH.

The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial.
GEH's competitive advantage will be lost if its competitors are able to use the results of the GEH experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

The value of this information to GEH would be lost if the information were disclosed to the public. Making such information available to competitors without their having been required to undertake a similar expenditure of resources would unfairly provide competitors with a windfall, and deprive GEH of the opportunity to exercise its competitive advantage to seek an adequate return on its large investment in developing and obtaining these very valuable analytical tools.

I declare under penalty of perjury that the foregoing affidavit and the matters stated therein are true and correct to the best of my knowledge, information, and belief.

Executed on this 24th day of October 2008.

Tim E. Abney
Vice President, Services Licensing
Regulatory Affairs
GE-Hitachi Nuclear Energy Americas LLC