NSP

Northern States Power Company

Monticello Nuclear Generating Plant
2807 West Hwy 75
Monticello, Minnesota 55362-9637

September 5, 1997

US Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

MONTICELLO NUCLEAR GENERATING PLANT
Docket No. 50-263 License No. DPR-22

Response to Request for Additional Information (RAI) on
Monticello Power Rerate Program (TAC No. M96238)

By letter dated April 14, 1997, the staff provided a request for additional information (RAI) to facilitate its review of NSP's license amendment request for the Monticello Nuclear Generating Plant (MNGP) Power Rerate Program. This letter provides NSP's response to the staff's request.

Please contact Joel Beres, Monticello Licensing, at (612) 295-1436 if additional information is required.

William J Hill

William J. Hill
Plant Manager
Monticello Nuclear Generating Plant

c: Regional Administrator - III, NRC
NRR Project Manager, NRC
Sr. Resident Inspector, NRC
State of Minnesota, Attn: Kris Sanda
J Silberg, Esq.

Attachments:

(1) Affidavit to the US Nuclear Regulatory Commission
(2) NSP RAI Response
(3) GE NEDC-32498, Rev. 1, "Reactor Pressure Vessel Power Rerate Stress Report Reconciliation for Monticello Nuclear Generating Plant"
(4) GE NEDC-32647, "Monticello Cobalt Transport and Shutdown Drywell Dose Rate Model Calculation Results"
(5) Figures 9, 10, and 12 of GE-NE-B1100683-1
(6) Load Histogram for Core Spray Piping / Safe End (Duty Map)
(7) EQ Profiles

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UNITED STATES NUCLEAR REGULATORY COMMISSION

NORTHERN STATES POWER COMPANY

MONTICELLO NUCLEAR GENERATI; G PLANT DOCKET NO. 50-263

Response to Request for Additional Information Regarding
License Amendment Request dated July 26, 1996

Northern States Power Company, a Minnesota corporation, by letter dated September 5, 1997 provides its response for the Monticello Nuclear Generating Plant to a US Nuclear Regulatory Commission (NRC) letter dated April 14, 1997, with the subject "Monticello Nuclear Generating Plant - Request for Additional Information on License Amendment Request Dated July 26, 1996 Entitled 'Supporting the Monticello Nuclear Generating Plant Power Rerate Program" (TAC No. M96238)'." This letter contains no restricted or other defense information.

NORTHERN STATES POWER COMPANY

By William J Hill
William J. Hill
Plant Manager
Monticello Nuclear Generating Plant

On this 5th day of September 1997 before me a notary public in and for said County, personally appeared William J. Hill Plant Manager, Monticello Nuclear Generating Plant, and being first duly sworn acknowledged that he is authorized to execute this document on behalf of Northern States Power Company, and that to the best of his knowledge, information, and belief the statements made in it are true.

Steph Blegen
Stephen R. Blegen
Notary Public - Minnesota
Sherburne County
My Commission Expires January 31, 2000

STEPHEN R. BLEGEN
NOTARY PUBLIC - MINNESOTA
My Comm. Exp. Jan 31, 2000

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Electrical Systems

1. *Information provided in Exhibit A (page A-24) indicates no change for normal conditions for temperature, pressure, and humidity inside containment for the power rerate conditions while Exhibit E (section 10.2.1.1) indicates a slight increase. Provide clarification.*

NSP Response

Exhibit E is incorrect, and the phrase "and normal" will be deleted. Except for radiation levels, normal environmental conditions in the drywell will not change as noted in Exhibit A page A-24. Containment pressure is regulated by procedure and will not change under rerate conditions. Humidity levels will remain the same as there is no operational change being made to affect humidity in the inerted containment atmosphere. Although a small increase in ambient temperature is expected, this increase is well within the capability of the drywell cooling system. Present administrative controls and procedures will assure that the bulk average drywell air temperature will stay within the limits of 135°F at rerate conditions.

The Exhibit E wording will be changed in NSP's revised license amendment request.

2. *Information provided in Exhibit A (page A-24) indicates no change for accident (design-basis accident/loss-of-coolant accident) (DBA/LOCA) conditions for temperature, pressure, and humidity inside containment for the power rerate conditions while Exhibit E (Section 10.2.1.1) indicates a slight increase. Provide clarification.*

NSP Response

Exhibit A is incorrect. It appears from Question 1 that some unintended administrative errors occurred in the description of the rerate changes in regard to equipment qualification.

Equipment required to be qualified per 10CFR50.49 are qualified to the bounding environmental conditions. The bounding accident temperature conditions in the drywell used for environmental qualification are based on the small steam line break accidents. The bounding accident pressure conditions in the drywell occur during the DBA LOCA. The humidity for accident scenarios is assumed to be 100%. The humidity assumption is not changed for rerate conditions.

The Monticello environmental qualification central file references General Electric Report AE-083-0983, "Extended Drywell Temperature Analysis, as containing the drywell accident temperature profile. The central file references General Electric Report NEDO-30485, "Monticello Design Basis Accident Containment Pressure and Temperature Response for FSAR Update," as containing the drywell accident pressure profile. General Electric Report NEDO-30477, "Safety Analysis of the RHR Intertie Line Monticello Nuclear Generating Plant" analyzed for the peak short term (30 second) containment response. This analysis reported a peak drywell pressure of 42.3 psig at 1.2 seconds. The environmentally qualified equipment inside containment was verified to be qualified to the peak drywell pressure of 42.3 psig.

Recent NSP correspondence with the staff addressed environmental qualification of equipment at 1880 MWt. Containment response curves for drywell temperature and pressure at an initial power level of 1880 MWt was provided by letter dated July 16, 1997. See "Response to Request for Additional Information Regarding Revision 2 to MNGP License Amendment Dated January 23, 1997." Power rerate results in a slight increase in the peak drywell temperature and in an extension of the temperature profile for the bounding 1880 MWt DBA LOCA case. See response to question 3.b below.

A comparison of the peak drywell environmental conditions for current and rerate power is presented in the table below. A improved containment model was used for the rerate evaluations and for re-evaluating containment response for current power (See Response to Question 50). Because of model improvements, the results from the revised containment response for 1670 MWt are different than the results for the EQ containment response of record. For comparison purposes , both sets of containment responses for the 1670 MWt case are shown in Table 2-1 below.

Table 2-1 Containment Response Parameters

RATED POWER LEVEL*	DBA-LOCA DRYWELL PEAK TEMP	SHORT TERM PEAK LOCA DW PRESSURE	SBA-LOCA DRYWELL PEAK TEMP
1670 MWt	282°F (1,2)	42.3 psig (3)	335°F (4)
1670 MWt	286.8°F (5)	40.6 psig (5)	330°F (6)
1880 MWt	285.5°F (5)	39.5 psig (5)	331°F (6)

Notes
(1) NEDO - 30485, Table 1; Code HXSIZ with May-Witt decay heat
(2) NEDO - 32418, Table 3-1; Code HXSIZ with ANS 5.1 decay heat
(3) NEDO -30477, Table 3-3 ; Code M3CPT with May-Witt decay heat
(4) AE-083-0983, Table 1; Code SHEX with May-Witt decay heat
(5) GE-NET2300731-1, Table 3; Code SHEX with nominal ANS 5.1 decay heat
(6) GE-NET2300731-1, Table D-1; Code SHEX with nominal ANS 5.1 decay heat

*Evaluations were conducted assuming 102% of the rated power level (e.g. 1703 MWt was assumed for the 1670 MWt case).

The Exhibit A wording will be changed in the revised rerate license amendment request.

3. *Slight increases in the current accident (DBA/LOCA) and normal conditions for temperature, pressure, and humidity for power rerate are considered insignificant as stated in Exhibit E (section 10.2.1.1).*

a. *Define the slight increases for temperature, pressure, and humidity*
b. *Explain why the slight increases are considered insignificant .*

1) *Has each piece of equipment been evaluated to ensure it is still qualified?*
2) *Explain why equipment remains qualified.*

c. *Section 10.1, Exhibit E, states that these increases are well within the margins in the existing environmental* qualification (EQ) envelopes

1) *Do these increases cut into test margins or do they cut into the margin between qualification levels and actual predicted profiles?*
2) *Define how margins are being cut.*

NSP Response

See Question 1 above for a discussion of normal conditions. The responses below address accident conditions.

a. *Define the slight increases for temperature, pressure, and humidity.*

NSP Response

The first row in Table 2-1 above shows the peak containment temperature and pressure conditions used as the basis for equipment qualification for the current power level. The table also shows that the current peak containment temperature and pressure used for equipment qualification bounds the temperature and pressure results for the 1880 MWt power level. For the short term condition, the EQ temperature profile is derived from the temperature response associated with the SBA-LOCA. The slight increase identified in Exhibit E is based on the DBA/LOCA containment response curves for temperature and pressure and reflects changes in non-limiting pressures and temperatures for the DBA/LOCA at long term conditions.

Humidity is assumed to be 100% for all power cases.

b. *Explain why the slight increases are considered insignificant .*

NSP Response

Certain accident profiles change under rerate conditions. As a result, the integrated exposure to temperature increases slightly. This slight increase, however, does not significantly affect thermal degradation and does not preclude qualification of the affected equipment.

Since portions of the 1880 MWt temperature response were not contained within the current power EQ temperature profile, an evaluation was performed to demonstrate qualification. An equivalent integrated temperature evaluation for EQ equipment in containment was calculated using the Arrhenius methodology. This methodology was previously approved by the Staff by its SER for Monticello dated January 4, 1983 (See section 4 therein).

In order to evaluate the differences, a drywell DBA temperature envelope was developed. The DBA temperature envelope was constructed by choosing points that bounded the 1880 MWt containment DBA temperature profile. The results from MNGP Calculation CA 97-176 show that the equivalent temperature exposure time for the EQ temperature evaluation profile exceeds the equivalent temperature exposure time for the DBA temperature profile. Therefore, the existing EQ temperature evaluation profile bounds the DBA temperature profile.

Portions of the 1880 MWt pressure response were not contained within the current power EQ pressure profile. This is considered acceptable since the current power peak containment pressure used for environmental qualification bounds the peak containment pressure at rerate conditions, and the failure mode mechanisms associated with the pressure parameter do not include time dependent aging effects.

The evaluation above supports containment equipment qualification with the current envelopes of pressure and temperature.

1) *Has each piece of equipment been evaluated to ensure it is still qualified?*

NSP Response

Equipment located in areas where temperature, pressure and humidity requires environmental qualification (EQ) was evaluated to determine the effect of changes (if any) to the environmental profiles. For equipment located in containment, equipment qualified at 1670 MW remains qualified at the rerate conditions since the profile used for qualification is still bounding. For areas outside containment an evaluation was completed that concluded that each piece of environmental qualified equipment would remain qualified at the 1775 MWt power level.

Prior to implementation of power rerate at MNGP, environmental qualification files will be revised to reflect the environmental profile changes required by the power rerate program.

2) *Explain why equipment remains qualified.*

NSP Response

Equipment located in areas where temperature, pressure and humidity conditions requires equipment qualification (EQ) was evaluated to determine the effect of changes (if any) to the environmental profiles. For the in containment area, equipment qualified at 1670 MWt remains qualified at the rerate conditions since the profile used for qualification is still bounding. For areas outside containment the environmental conditions tested to exceeds the expected environmental conditions at 1775 MWt power level with the one exception noted. No new environmentally harsh areas are created at power rerate conditions.

c. *Section 10.1, Exhibit E, states that these increases are well within the margins in the existing environmental qualification (EQ) envelopes.*

1) *Do these increases cut into test margins or do they cut into the margin between qualification levels and actual predicted profiles?*

NSP Response

These increases do not affect test margins. DBA/LOCA containment response curves for temperature and pressure, as discussed above, contain changes in non-limiting pressures and temperatures for the DBA/LOCA at long term conditions as compared to the current power EQ containment response curves.

The margin between the predicted profiles (the analytical response) and the EQ evaluation profile (a tool for EQ evaluation purposes that is a conservative approximation of the analytical response) has been reduced. The margin between the EQ evaluation profile and the test profile has not been reduced.

2) *Define how margins are being cut.*

NSP Response

Please see the response to 3.b and 3.c.(1) above.

4. *Provide an EQ Package for one piece or type of electric equipment that is within the scope of 10 CFR 50.49 which demonstrates (1) continued qualification for the rerate environment and (2) the process for establishing qualification for the increased temperature, pressure, humidity and radiation levels for power rerate.*

See the attached EQ file.

5. *On page A-58 it is implied that minor modifications (required to assure the continued qualification of electrical equipment outside the scope of 10 CFR 50.49) are not considered unreviewed safety questions and thus will be implemented under the provisions of 10CFR 50.59 during implementation of power rerate. 10 CFR 50.59 requires, in part, that a proposed change be deemed to involve an unreviewed safety question if the probability of malfunction of equipment important to safety previously evaluated in the safety analysis report may be increased. The increase in system temperature, pressures, or power requirements identified to exist on page A-24 Exhibit A (no matter how minor) can be interpreted to increase the probability of malfunction of heat sensitive electrical equipment important to safety. Thus, any modification to electrical equipment due to increased temperature, pressures, or power requirements associated with MNGP power rerate could be considered an unreviewed safety question. Explain why (or how) these future modifications (which have yet to be identified) should (or will) not be considered unreviewed safety questions.*

Electrical equipment outside of the scope of 10CFR 50.49 has been evaluated to ensure that it remains within appropriate design limits. This equipment will operate at the same flow rates and pressures as currently allowed. Temperatures for ambient conditions will be maintained within original design limits.

The modification program requires the screening of each modification for 10CFR50.59 applicability. Page A-58 states "minor system modifications are to be performed to enhance the capacities and capabilities of installed plant systems." Exhibit D lists those minor system modifications. None of these listed modifications are to equipment that requires environmental qualification or are in the scope of the EQ program. This list of hardware changes does not involve electrical equipment important to safety and therefore would not be an unreviewed safety question.

The equipment referred to in Exhibit A page A-24 will be qualified for its application and location in accordance with 10 CFR 50.49. This includes all equipment within the scope of 10 CFR 50.49.

Page A-24 identifies that equipment qualification can be met in almost all cases. NSP's evaluation identified the following components that require additional work.

- One cable type that meets qualification requirements at 1775 MWt power level, but that additional testing, documentation or cable replacement with a different cable type would be required at 1880 MWt power level.

- One type of conduit seal would have a reduced qualified life in some applications at 1775 MWt power level, and would require replacement, reanalysis or retesting at 1880 MW power level.

6. *Section 6 of Exhibit E indicates that a Northern States Power (NSP) grid stability analysis has been performed at 1775 MWt to verify no significant effects on grid stability and reliability. Explain why there are "no significant effects on grid stability and reliability."*

NSP Response

It is important to note that Monticello is not licensed to the requirements of GDC 17 of Appendix A to 10 CFR 50 and is not licensed to the stability criteria of any IEEE standards. However, in light of the staff's recent concerns with electric grid reliability and in accordance with good engineering judgment, NSP determined that a calculation to address these concerns was prudent. NSP Calculation CA 97-144, "Summary of the Effects of MNGP Power Rerate on Transmission System Reliability and Stability," has been completed and shows that the transmission system remains stable and reliable with MNGP initially operating at 1775 MWt for the following grid contingencies identified in IEEE Standard 765, "Preferred Power Supply for Nuclear Power Generating Stations."

(1) Loss of the nuclear power generating unit
(2) Loss of NSP's largest generating unit
(3) Loss of the largest transmission circuit or intertie
(4) Loss of largest system load

The acceptance criteria for stability and reliability is based on the design standards for bulk transmission system performance as delineated by the Mid-Continent Area Power Pool (MAPP). These standards include, among other requirements, steady state pre-contingency voltage limits of 0.95 to 1.05 pu and post-contingency voltage limits of 0.9 to 1.1 pu.

NSP requests that this calculation not be misconstrued as a commitment to change the plant's licensing basis in the future.

7. *Provide results of analysis which demonstrates that sufficient power will remain available and connected to safety systems from the offsite system (transmission network) immediately following reactor trip caused by LOCA when operating MNGP at 1775 MWt for all expected modes of operation of the transmission network.*

NSP Response

Please note that the response for Question 7 is contained in the response to Question 10.

8. *Provide results of analysis (or other justification) which demonstrates that there has been no reduction in margin (due to power rerate) between trip setpoints for loss of voltage or degraded grid voltage protective schemes installed on safety buses and transient voltage on safety buses that are expected following reactor trip due to a LOCA.*

NSP Response

Please note that the response to Question 8 is contained in the response to Question 10.

9. *Technical specifications will allow plant operation with the IR and 2R transformers operable while the 1AR transformer is out of service. It is not clear that the 1R and 2R transformers each have sufficient capacity and capability to supply safety-related loads for this mode of operation. It is also not clear if operability requirements need to be established for the automatic load shedding feature on the 1R transformer (or for the administrative procedures for limiting load on the 1R transformer) for this mode of operation. Provide technical specification changes that preclude this mode of operation or provide a system description, the results of analysis that demonstrate compliance with design-basis requirements, and proposed limiting conditions for operation (if applicable) for this mode of operation.*

NSP Response

Please note that the response to Question 9 is contained in the response to Question 10.

10. *Technical specifications will allow plant operation with the 1R and 1AR transformers operable while the 2R transformer is out of service. Provide technical specification changes that preclude this mode of operation or provide a system description, the results of analysis that demonstrate compliance with design-basis requirements, and proposed limiting conditions for operation (if applicable) for this mode of operation.*

NSP Response

Please note that the responses for Questions 7 through 10 inclusive are contained in the response to Question 10.

The central issue to questions 7 through 10 is the effect of rerate upon the operation of the 1R transformer. The 2R transformer has significant loading margin and does not approach any loading limitations due to the increase in loads due to rerate. The 1AR transformer scheme includes a load shed that leaves only the safety related buses. The 1AR loads are not affected by power rerate. In addition to the 1R X winding loading issue discussed in detail in the response to Question 11 below, the following issues describe the effect of rerate for 1R transformer as currently configured.

The rerate loading analysis has focused more attention on voltage capabilities of the local 115 KV System. Currently, the plant has administrative limits on minimum 115 KV system voltage which are dependent upon whether No. 10 transformer is in service. The "strong grid" (low grid impedance) case is when No. 10 transformer is in service to provide a lower impedance connection between the 345 KV transmission system and the 1R primary winding. The "weak grid" case is the case when No. 10 transformer is not in service. Under the weak grid cases, the minimum 115 KV system voltage is required to be higher than the strong grid case. A minimum voltage requirement corresponds to that voltage sufficient to recover steady state voltage above the degraded voltage reset point when the plant is on 1R and No. 10 transformer is out of service. Under rerate conditions, the minimum voltage requirement increases above present limits, and this voltage may not be available from the grid unless special provisions are made.

NSP has been considering several options to address the above issue as well as the 1R X steady state loading issue discussed in the response to Question 11 below. As discussed in a September 4, 1997 phone conversation with the staff, tap changes to plant transformers have excellent potential for resolving the 1R loading issues.

Currently, the no load tap on 1R is positioned to the 115,000-4160 position. The engineering staff is analyzing the effects of changing the 1R tap setting to the 112,125-4160 position which would result in higher secondary voltages for a given primary voltage. In conjunction with this change, new lower 115 KV grid voltage limits and a lower No. 10 transformer LTC voltage control band would be established. Preliminary calculations indicate that the new 1R tap position, when coupled with the revised 115 KV allowable voltage band and the revised No. 10 transformer LTC voltage control band, would significantly improve load margin for 1R and would also serve to eliminate the operational dependencies for 1R on the availability of the 10 transformer. This change would therefore obviate any technical specification changes which may have been necessary under the present configuration.

Due to the significant improvement in offsite source reliability and availability which appears to be achievable via the change in 1R tap settings and the new 115 KV operating limits, NSP intends to pursue the above changes outside of the rerate program. In order to address rerate issues, however, the supporting calculations will support rerate loading conditions. When calculations for the new configuration at rerate conditions have been formalized, a separate submittal will be made to provide background information on the tap settings and to provide supporting analyses from the load study for staff review. This submittal will more fully address Questions 7 through 10 for the 1R transformer. The expectation is that this information will be submitted by September 30, 1997.

11. *Page 2 of 3 of Updated Safety Analysis Report (USAR) 8.2 Revision 12 states that the 1R transformer is of adequate size to provide the plant's full auxiliary load requirements. Exhibits A and E of the rerate submittal indicate that the MNGP design has been modified (and will be further modified as part of rerate) such that the capacity of the 1R transformer is something less than the 100 percent capacity required by the licensing basis for MNGP documented in the USAR. Provide the description and analysis for this modification.*

NSP Response

With existing plant auxiliary system loading and substation voltage limits, the 1R transformer is of adequate size to provide the plant's full auxiliary load requirements. The 1R transformer is rated at 37.33 MVA and has 2 secondary windings, designated X and Y, each of which are rated for 18.67 MVA. The X winding supplies the Reactor Feed Pump and Reactor Recirc MG set motors and is loaded to a higher level than the Y winding. 1R has a relatively high impedance which results in a voltage drop across the X winding of the transformer. The plant's load study calculations indicate that with the USAR minimum source voltage of 117.5 KV present on the 115KV system which supplies the 1R primary winding, 3885 V would be available on the loaded X winding secondary under steady state non-accident conditions.

As transformer MVA ratings are based upon secondary winding current carrying limitations, it is Monticello's practice to proportionately derate the transformer MVA rating directly with the percent in which loaded secondary voltage is below transformer rated secondary voltage. For the 1R X winding, this results in a derate to 3885 / 4160 * 100 or approximately 93.4% (17.4 MVA). For existing plant full auxiliary load conditions, the X winding is loaded to 16.7 MVA or 89.5%. As the degree of loading (89.5%) is less than the derated MVA limit (93.4%), 1R is of adequate size to provide present full plant auxiliary load requirements.

Under rerate conditions, the higher loading on the feed pump motors results in a calculated X winding loading of 17.5 MVA (93.7%). This increased loading also results in an increased voltage drop across the 1R X winding such that approximately 3853 V will be present when the 115KV source voltage is at the USAR minimum value of 117.5 KV. Applying the reduced voltage derate as discussed above, the X winding MVA limit drops to 3853 / 4160 * 100 or approximately 92.6%. Thus for the present 1R configuration and substation voltage limits, rerate loading levels would result in X winding loading (93.7%) in excess of the rerate derated MVA limit (92.6%). The limits referred to in Exhibits A and E of the rerate submittal were intended to inform the staff of NSP's intent to establish controls such that the 1R X winding would not be loaded beyond its derated MVA limit.

NSP intends to obviate this 1R X winding loading concern via the change in the 1R primary tap setting and establishment of new 115KV system voltage limits as discussed in the response to Questions 7 through 10 above. Preliminary calculations indicate that the higher available voltages which will be available on the 1R secondary windings will lower the amount of MVA derate required such that 1R X winding loading would be less than the derated MVA limit under rerate conditions.

12. *Provide an assessment of how the proposed thermal uprate will affect the end of life (EOL) upper shelf energy analysis for Vessel Plate No. I-15 (Heat No. C2220-2), and the equivalent margins analyses for Vessel Plates I-16, I-17, and I-14 (Heat Nos. A0946-1, C2193-1, and C2220-1) and the beltline vessel welds (no heats given). Include appropriate calculations, figures, or references demonstrating continued compliance with the requirements of 10 CFR Part 50, Appendix G, under the proposed increased power conditions and also updated values for the 1/4T fluence and the upper shelf energies for beltline materials of the MNGP reactor pressure vessel (RPV) at EOL.*

NSP Response

Table 12-1 lists the conservatively estimated EOL 1/4 T fluence value at a power uprate of 112.6% (1880 MWt) to be 3.99E+18 n/cm^2. Using Figure 2 from Reg. Guide 1.99 Rev. 2 and the fluence value of 3.99E+18 n/cm^2, the percent decrease in shelf energy can be determined. Listed below are the results of the decrease in USE (Upper Shelf Energy) for the Monticello beltline materials based on uprate. Table 12-2 lists the estimated EOL 1/4 T fluence at 1670 MWt without taking rerate into consideration.

TABLE 12-1 (Effects on USE at Rerate Conditions)

Plate / Weld	Heat Weld Type	INITIAL TRANS. USE	%Cu	E.O.L. FLUENCE E+18 n/cm2	%Decr. USE	E.O.L. TRANS. USE
I-14	C2220-1	59.1 (1)	.17	3.99	20.9	46.7(2)
I-15	C2220-2	71.0 (3)	.17	3.99	20.9	56.2(4)
I-16	A0946-1	59.1 (1)	.14	3.99	18.5	48.2(2)
I-17	C2193-1	59.1 (1)	.17	3.99	20.9	46.7(2)
Weld		87.0 (1)	.10	3.99	19.4	70.1(4)

Notes
(1) Initial Transverse USE values were obtained from NEDO-32205-A, (10CFR50 Appendix G Equivalent Margin Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels)
(2) Acceptable value per NEDO-32205-A is $\geq$35 ft-lbs.
(3) From response to GL 92-001 (Reactor Vessel Structural Integrity). This value is also identified in the Reactor Vessel Internals Data Base.
(4) Acceptable Value per Appendix G of 10CFR 50 is $\geq$ 50 ft-lbs.

TABLE 12-2 (Effects on USE at Current Conditions).

Plate / Weld	Heat Weld Type	INITIAL TRANS. USE	%Cu	E.O.L. FLUENCE E+18 n/cm2	%Decr. USE	E.O.L. TRANS. USE
I-14	C2220-1	59.1 (1)	.17	3.82	20.6	46.9(2)
I-15	C2220-2	71.0 (3)	.17	3.82	20.6	56.4(4)
I-16	A0946-1	59.1 (1)	.14	3.82	18.1	48.4(2)
I-17	C2193-1	59.1 (1)	.17	3.82	20.6	46.9(2)
Weld		87.0 (1)	.10	3.82	19.0	70.5(4)

Notes
(1) Initial Transverse USE values were obtained from NEDO-32205-A, (10CFR50 Appendix G Equivalent Margin Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels)
(2) Acceptable value per NEDO-32205-A is >35 ft-lbs.
(3) From response to GL 92-001 (Reactor Vessel Structural Integrity). Also value is identified in Reactor Vessel Internals Data Base .
(4) Acceptable Value per Appendix G of 10CFR part 50 is ≥ 50 ft-lbs.

Given the above, the upper shelf energies for I-14, I-15, I-16, I-17, and the limiting weld are all above the acceptable upper shelf acceptable energy levels for both rerate and current conditions. In addition, a comparison of Table 12-1 to Table 12-2 shows that the difference in USE values are insignificant.

Question 12 References

1. NEDO 32205-A, (10CFR50 Appendix G Equivalent Margin Analysis for Low Upper Shelf Energy in BWR/2 Through BWR/6 Vessels.
2. Reg. Guide 1.99 Rev 2, (Radiation Embrittlement of Reactor Vessel Materials).
3. Response to GL 92-001, (Reactor Vessel Structural integrity)
4. Reactor Vessel Integrity Database Summary File for Upper Shelf Energy.

13. *Provide an assessment of how the uprated conditions will affect the scope or schedule of the surveillance capsule withdrawal program (10 CFR Part 50, Appendix H Program) for the MNGP RPV.*

NSP Response

No changes in the Appendix H program are required because there are no significant changes in criteria important for Appendix G. The relevant criteria are the system pressures and the vessel fluence at End-of-Life. Or more precisely, the end of the current license. The system test pressure used for the current P-T curves is 1100 psi, which bounds both the current nominal operating pressure and the nominal operating pressure for rerated conditions. Any revisions to these P-T curves would similarly be expected to bound operating pressures for both current and rerated conditions. The neutron fluence calculated for the end-of-license time period with the addition of rerated power operation to 1775 MWt is very close to the same numerical value of neutron fluence that was calculated for a 40-year plant license operating at 1670 MWt. This occurs because the operating capacity factor for Monticello to date is about 75% compared to the original assumption of 80%. Thus operation at 106.3% of 1670 MWt for the balance of the current license period results in a total integrated fluence level very close to that corresponding to an average 80% capacity factor over a 40-year license operating at 1670 MWt the entire time period.

14. *Provide a more detailed evaluation of the effects caused by extended power uprate on reactor internals (i.e., expand on your submitted determination of the effects).*

Power rerate has only a limited effect on the reactor internals. Most of the operational parameters defining the operating environment for the reactor internals are unchanged for power rerate operation. The maximum reactor operating pressure is unchanged. The core flow operating range at rerated power is bounded by the core flow range at current power. The maximum recirculation drive flow is unchanged for power rerate operation because the recirculation system is currently at the maximum flow during increased core flow operation. The downcomer and core inlet enthalpy range at rerated power is bounded by the enthalpy range at current power. The maximum steam generation in any single fuel bundle is unchanged for power rerate because the bundle thermal limits remain the same for power rerate.

The primary effect of power rerate operation is a slight increase in the reactor internal pressure differences (RIPDs). The increase in RIPDs is due to the higher two-phase flow losses caused by the increased steam generation in the core. The reactor internals have been evaluated for the higher RIPD loading at normal, upset, and faulted conditions due to power rerate in NEDC-32546P, Section 3.3.2.1.

Further information on the reactor internals stress evaluation is presented below in response to Question 17. This response shows the expected changes in stress levels for the highest stressed reactor internals locations. See also NEDC-32498, Revision 1, provided in response to Question 19 for further information on reactor internals stress evaluations done for Rerate. This is consistent with the approach defined in Section I.3 of NEDC-32424P, "Generic Guidelines for General Electric Boiling Water Reactor Extended Power Uprate" (ELTR1).

The steam separators see a higher inlet quality and the steam dryers see a higher flow velocity as a result of the increased steam generation in the core. The steam dryer and separator performance evaluation is presented in NEDC-32546P, Section 3.4.

Intergranular stress corrosion cracking and erosion/corrosion have been addressed generically for the reactor internals in Section 3.6.1 of NEDC-32523P, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR2) for extended power uprates up to 20%.

15. *Provide a more detailed evaluation of the effect caused by extended power uprate on components exposed to single- and two-phase fluid flow.*

NSP Response

As described in the response to Question 14, the steam separators and steam dryers are the only reactor internals components that experience a change in the fluid flow conditions for power rerate. The steam separators see a higher inlet quality and the steam dryers see a higher flow velocity as a result of the increased steam generation in the core. Intergranular stress corrosion cracking and erosion/corrosion have been addressed generically for the reactor internals in Section 3.6.1 of NEDC-32523P, "Generic Evaluations of General Electric Boiling Water Reactor Extended Power Uprate," (ELTR2) for extended power uprates up to 20%.

Mechanical Engineering

16. *In reference to Section 2.5.1 of Exhibit E, provide an evaluation of the control rod-drive mechanism with regard to the stress and fatigue usage as a result of the 6.3 percent power uprate. Also, provide the allowable code limits for the critical components evaluated, and the code and code edition used for the evaluation. If different from the code of record, justify and reconcile the differences.*

NSP Response

The control rod drives (CRDs) are in direct communication with the reactor pressure vessel and are exposed to reactor pressure and temperature. Since the reactor pressure and temperature remain unchanged for a power uprate of 6.3%, the original design conditions for the CRDs are applicable.

The CRDs have been designed for 1250 psig which is higher than the bottom head pressure of 1045 psig for normal and power uprate reactor conditions. The components of the CRD mechanism, which form part of the primary pressure boundary, have been designed in accordance with the applicable ASME B&PV Code, Section III .

The limiting component of the CRD mechanism is the indicator tube which has a calculated primary membrane plus bending stresses of 20,790 psi. The allowable stress is conservatively specified as 26,060 psi (i.e., 1.5 Sm). The maximum stress on this component results from the maximum CRD internal hydraulic pressures of 1750 psig caused by an abnormal operating condition.

The CRDs have been designed for temperatures of up to 575°F, which is higher than the bottom head temperature of 530°F for normal and power uprate conditions. The analysis for cyclic operation of the CRD was conservatively evaluated in accordance with applicable requirements specified in the ASME B&PV Code, Section III. For example, when considering the loadings resulting from scram with a leaking scram discharge valve, scram with a failed buffer, and scram without CRD cooling water flow, the limiting component was found to be the CRD main flange. The fatigue usage factor is 0.15 which is less than the allowable limit of 1.0. All requirements are satisfied even when considering the increased power uprate vessel bottom head pressure, thereby satisfying the peak stress intensity limits governed by fatigue.

Since the reactor pressure and temperature remain unchanged for power rerate, the original evaluation of the CRD for stress and fatigue usage, described above, remains applicable.

17. *In regard to Section 3.3.2, provide the maximum calculated stress at the critical locations of the reactor internal components, the allowable code limits, and the code and code edition used in the evaluation for the power uprate. If different from the code of record, provide justification.*

NSP Response

The evaluation of the reactor internals uses ASME Boiler and Pressure Vessel Code Section III as a guide for design acceptance criteria; no specific edition or addenda was specified. The specific applicable Code Edition for the reactor pressure vessel, including the shroud support, is the 1965 Edition with Addenda to and including the Summer 1966 Addenda.

The structural integrity of the component is demonstrated by comparison with applicable allowable stresses. The stress results for three of the highest stress components are shown in Table 17-1.

Table 17-1: Selected Results, Reactor Internals Stress Summary

COMPONENT	MAX. STRESS LOCATION	UPSET			FAULTED		
		Max. Value Current psi	Max. Value Rerate psi	Allowable ** psi	Max. Value current psi	Max. Value uprate psi	Allowable ** psi
Shroud Support	Shroud Supt. Cylinder	15,575	<22,900*	34,650	Not Determined	22,900	69,900
Core Plate	Beam Buckling Stress	5,170	5,560	6,200	6,748	6,748	12,400
Jet Pump Assembly	Riser Elbow Stresses	9,052	10,156	38,025	29,719	33,344	60,840

* This value is less than allowable by inspection of the faulted value. No calculation was performed.

** The allowable values are based on the code of record.

18. *In Section 3.3.2.2, an assessment of flow-induced vibration of the reactor internal components due to power uprate is performed to address the increase in steam product in the core, the increase in the core pressure drop, and the increase in the recirculation pump speed. In that assessment, the vibration levels were estimated by extrapolating the recorded vibration data at Monticello and by using the operating experience of similar plants. Provide a sample evaluation and the basis for using the operating experience of similar plants.*

NSP Response

During the start-up flow induced vibration testing of the Monticello Nuclear Power Station, vibration data for the reactor internal components were recorded during the cold flow pre-operational testing and hot flow power operation of 50%, 75%, and 100% rod line testing. Operating conditions during these tests included steady-state balanced flow two pump operation, unbalanced flow, single loop operation, and transient flow conditions. The observed vibration responses were all well below the acceptance criteria limits under all tested conditions. See Section 3.6.3.1 of the Monticello USAR for additional information on measurements, acceptance criteria and the basis for using operating experience from similar plants.

The acceptance criteria comprise a set of frequencies and corresponding allowable amplitudes derived from an analytical model. An acceptance criteria of 100% corresponds to a peak stress intensity of 10,000 psi due to vibration. At this stress level, sustained operation is allowed without incurring any fatigue usage. When the stress level exceeds 100% of acceptance criteria, the component is subjected to fatigue usage.

Vibration data obtained from operating BWR plants have shown conclusively that, for a broad range of BWR sizes, the conservatively chosen long term steady state vibration criteria are not violated for normal balanced flow conditions. Since all BWR jet pump plants are geometrically similar, it is not expected that there is any significant difference in vibration response of plants in various limited size ranges. Therefore, a complete series of vibration tests is not necessary for individual units. Monticello is one of the units that was instrumented and measured by General Electric to obtain vibration testing data.

Two sets of extrapolations beyond the bounds of the original test data were made to account for the potential effects of rerate operation. One extrapolation was made to determine the effect of increasing core flow with a nearly constant rod line and the other to determine the effect of increasing rod line with nearly constant core flow. Figures 9, 10 and 12 of GE-NE-B1100683-1 (attached) are provided as an example. In these figures test data existed for a 50% rod line to 108% core flow, and therefore no extrapolation was needed for this case. Extrapolations that were made were shown with dashed lines on the figures.

Since the start-up tests were not performed with operating conditions in the proposed power rerate region, the expected vibration responses were estimated from the existing start-up test data. Extrapolation from the start-up test conditions to the power rerate operating condition provides a reasonable estimate of the expected vibration level. Two sets of extrapolations were made: 1) a set to determine the effect of increasing core flow with nearly constant rod line, and 2) a set to determine the effect of increasing rod line with nearly constant core flow.

The extrapolation procedure is an accepted engineering practice and has also been applied to the flow induced vibration evaluations for all other GE BWR power rerate programs. Power rerate operational testing has been conducted at one other GE BWR plant. Reactor internal components with similar designs as Monticello have shown no significant increase in flow induced vibration and have also shown that vibration levels are within the extrapolated values.

During the start-up flow induced vibration testing of the Monticello Nuclear Power Station, vibration data for the reactor internal components were recorded during the cold flow pre-operational testing and hot flow power operation of 50%, 75%, and 100% rod line testing. Operating conditions during these tests included steady-state balanced flow two pump operation, unbalanced flow, single loop operation, and transient flow conditions. The observed vibration responses were all well below the acceptance criteria limits under all tested conditions.

Since the start-up tests were not performed with operating conditions in the proposed power rerate region, the expected vibration responses were estimated from the existing start-up test data. Extrapolation from the start-up test conditions to the power rerate operating condition provides a reasonable estimate of the expected vibration level. Two sets of extrapolations were made: 1) a set to determine the effect of increasing core flow with nearly constant rod line, and 2) a set to determine the effect of increasing rod line with nearly constant core flow.

The extrapolation procedure is an accepted engineering practice and has also been applied to the flow induced vibration evaluations for all other GE BWR power rerate programs. Power rerate operational testing has been conducted at one other GE BWR plant. Reactor internal components with similar designs as Monticello have shown no significant increase in flow induced vibration and have also shown that vibration levels are within the extrapolated values.

19. *In reference to Sections 3.3 and 3.3.2, provide the methodology, assumptions, and loading combinations used for evaluating the reactor vessel and internal components with regard to the stresses and fatigue usage for the power uprate. Were the analytical computer codes used in the evaluation different from those used in the original licensing-basis analysis? If so, identify the new codes used and provide justification for using the new codes and state how the codes were qualified for such applications.*

<u>NSP Response</u>

Reactor Vessel
The methodology, assumptions, and loading combinations used for evaluating the reactor vessel components with regard to the stresses and fatigue usage for power uprate are provided in GE Report No. NEDC-32498 Revision 1 (attached). No new analytical computer codes were used in the evaluation.

Reactor Internals
This evaluation primarily considers the concern that operation at rerate power level may subject reactor internal components to greater reactor internal pressure differentials (RIPDs) than previously considered. The operational basis earthquake and maximum earthquake loadings on reactor internal components are not affected by power rerate, but these loadings must be considered in appropriate combination with those loadings which are affected by rerate operation. Load combinations and stress limits from the structural criteria for reactor internals in Section 12.2.1.4 of the USAR were utilized for the power rerate evaluation. The stresses or loads for the

major reactor internal components were evaluated by either confirming that rerate load combinations are bounded by previous analyses or scaling stresses using conservative load ratios from these analyses. In some cases, previous analyses were repeated as required to demonstrate acceptance. No new computer codes were used in these evaluations.

20. *In reference to Section 3.6, provide the methodology and assumptions used for evaluating the reactor coolant piping systems for the power uprate. Also, provide the calculated maximum stress, critical locations, allowable stress limits, and the code and code edition used in the evaluation for the power uprate. If different from the code of record, justify and reconcile the differences.*

NSP Response

The reactor coolant pressure boundary piping design is based on the reactor pressure vessel (RPV) design temperature and pressure. There are no changes in the RPV design temperature and pressure due to power rerate as stated in Section 3.2 of the power rerate license amendment request. Therefore, the existing piping design and pipe stress analyses for the reactor coolant pressure boundary piping for the main steam piping, feedwater piping, CRD piping, RPV bottom head drain line, RPV head vent line, RCIC steam piping, Core Spray piping, RHR piping, HPCI steam piping, SRV discharge piping and RWCU piping bound the power rerate conditions.

Additional evaluation of the reactor recirculation system piping is provided below. Refer to the response to Questions 21 and 27 for a discussion of the main turbine stop valve closure loads impacting the main steam lines as well as the HPCI steam piping and SRV discharge lines which are attached to the main steam lines. For the evaluation of the main steam piping, feedwater piping, RCIC piping, Core Spray piping, RHR piping and HPCI piping not within the reactor pressure boundary, refer to the response to Question 24. The SRV discharge piping evaluation for Mark I Containment hydrodynamic loads is contained in the response to Question 26.

The design of the recirculation system piping including the applicable codes and stress limits is described in Sections 12.2.1.9 and 12.2.2.12.7 of the USAR. Piping and supports were designed for pressure, temperature, seismic and thermal transients due to normal and upset conditions. The operating parameters for the recirculation system such as temperature, pressure and heatup/cooldown rate will remain unchanged under rerated conditions. Therefore, power rerate has no impact on the design thermal transients, and the existing fatigue analyses of the recirculation piping bounds the power rerate conditions. The existing recirculation piping stress analyses used the code of record as described in the USAR.

The recirculation system piping was designed to ensure flow induced vibration stresses under steady state and transient vibration do not exceed acceptable limits. Under power rerate conditions, the recirculation system operating conditions that influence system vibration such as flow and pump speed will not be increased beyond the flows and pump speeds that have been used in the past. Therefore, the existing recirculation system vibration analysis bounds power rerate conditions.

In conclusion, there are no changes to the reactor pressure boundary piping design parameters for power rerate, therefore, the existing piping evaluations bound power rerate conditions. The current calculated maximum stress, critical locations, allowable stress limits, the code and code edition used for piping evaluation are not changed for power rerate.

21. *Discuss the analytical methodology and assumptions used in evaluating pipe supports, nozzles, penetrations, guides, valves, pumps, heat exchangers, and anchors at the power uprate conditions. Were the analytical computer codes used in the evaluation different from those used in the original licensing-basis analysis? If so, identify the new codes and provide justification for using the new codes and state how the codes were qualified for such applications.*

NSP Response

As stated in the response to Question 20, there are no changes in the RPV design temperature, pressure, or severity of recirculation system thermal transients due to normal and upset conditions under power rerate conditions. Except for main steam stop valve loads, power rerate has no impact on piping within the reactor coolant pressure boundary (RCPB) including pipe support loads, nozzles (e.g. RPV nozzles), penetrations (e.g. containment penetrations), guides, valves, pumps and anchors. The existing temperature and pressure design values for the above equipment bound the power rerate conditions. Consequently, no computer codes different than those used in the original licensing-basis analysis were used in RCPB power rerate evaluations.

Methodology and assumptions used in the analysis of piping was consistent with the descriptions provided in USAR Section 12 with piping issues predominantly described in USAR Sections 12.2.1.4, 12.2.1.10 with all subparts, 12.2.2.10 and 12.2.2.12 with all subparts. No changes were made to methodology or assumptions previously communicated with the NRC. The predominant impact for some systems not associated with the RCPB was a small change in temperature used for design values. Further discussion of non-RCPB piping analysis is provided in the response to Question 24.

There is an increase in main turbine stop valve closure loads due to rerate which impacts the main steam system piping back to the reactor vessel nozzles. Refer to the response to Question 27 for a discussion of the main turbine stop valve closure loads on the main steam, SRV discharge and HPCI steam piping, pipe supports and associated equipment. There are no heat exchangers within the reactor pressure boundary piping. The evaluation of the heat exchangers not within the reactor coolant pressure boundary is discussed in the response to Questions 24, 28 and 29.

22. *The power uprate fatigue cumulative usage factors (CUFS) (shown in Table 3-4) for the reactor vessel are given in three locations: at the refueling bellows skirt, the closure region bolts, and the recirculation inlet nozzles. Provide CUFs for the limiting components of the reactor coolant piping systems. Discuss how the calculated CUFs for the reactor vessel and piping components compare to the CUFs resulting from the actual loading cycles based on the data recorded during plant operation.*

NSP Response

(Part 1) CUFs for the Limiting Components of the Reactor Coolant Piping Systems

Monticello piping was originally designed and installed in accordance with USAS B31.1.0-1967 which did not require a fatigue analysis. The following reactor coolant pressure boundary piping systems were replaced, or added, since initial plant operation. The modifications for the replacements, or additions, considered the requirements of ASME Boiler and Pressure Vessel Code, Section III, Class I and as such now have fatigue evaluations.

RHR intertie line (added in 1984)

RHR shutdown cooling supply and return lines (replaced in 1984)

Recirculation system lines (replaced in 1984)

Core spray lines (replaced in 1986)

Fatigue analyses was performed using a duty map that provided a bounding set of assumed thermal cycles that may occur over the life of the plant. Fatigue evaluations for the replacement piping, based on these postulated thermal cycles, resulted in calculated usage factors of approximately, but less than 1.0. Conservative sets of assumed design cycles were used for the fatigue analyses. An example of the core spray duty map is attached.

(Part 2) Comparison of Actual Loading Cycles and Calculated Fatigue:

For cycle counting, actual plant cycles were conservatively classified relative to design cycles. That is, the actual thermal transient is typically less severe than the assumptions shown on the duty map. The core spray duty map assumes a 100 °F/hr heatup rate followed by a cooldown rate derived from a core spray injection from operating conditions. For counting purposes at Monticello, a normal cooldown cycle of less than 100 °F/hr is conservatively considered to be equal to a core spray injection. For piping, this conservative counting of experienced cycles showed a maximum CUF of 0.25 for the time period from 1986 to date for core spray piping. Extrapolating the Core Spray data, a life of over 40 years (1/0.25 x 11 years) is predicted before a usage factor of 1.0 is reached. This significantly exceeds the end of the current operating license. It should be pointed out that rerate operation does not impact fatigue on plant piping systems that have fatigue evaluations since there is no change in design temperature, pressure or thermal rate of change for the piping.

Similarly, the fatigue analyses for the vessel components in Table 3-4 are based on conservative sets of assumed design cycles. The current maximum actual usage has occurred for the refueling bellows skirt. Based on conservative counting of experienced cycles, fatigue usage is approximately 0.50 after 26 years of plant operation. By extrapolating the experienced cycles, a life of 26 additional years is indicated until a fatigue usage factor of 1.0 is reached. Due to the bias of increased startup/shutdown cycles experienced during early plant operations, this extrapolation is conservative.

Each of these calculations and extrapolations is based on conservative analysis and conservative characterization of experienced cycles. Additional margin in calculated fatigue is available if more detailed analysis and less conservative characterization of experienced cycles are used.

23. *Discuss the operability of safety-related mechanical components (i.e., valves and pumps) affected by the power uprate to ensure that the performance specifications and technical specification requirements (e.g., flow rate, close and open times) will be met for the proposed power uprate. Confirm that safety-related motor-operated valves (MOVS) will be capable of performing their intended functions) following the power uprate including such affected parameters as fluid flow, temperature, pressure and differential pressure, and ambient temperature conditions. Identify mechanical components for which operability at the uprated power level could not be confirmed.*

NSP Response

(Part 1) As stated in Section 4.3 of Exhibit E of the LAR, the "current ECCS system performance requirements were used in the power rerate analysis." There were no changes in flow rates, pump differential pressures or valve operating times from what is used in the current 1670 MWt calculations.

HPCI and RCIC were evaluated for operation at a RPV pressure of 1142.3 psig. This is equivalent to the SRV opening setpoint of 1109 psig with a + 3% as-found tolerance as allowed by Code. The nominal SRV setpoint of 1109 psig will not be changed for rerate. The low-low set SRVs have logic that, following a scram, opens one SRV at 1052 psig, a second SRV at 1062 psig, and a third SRV at 1072 psig. A high reactor pressure scram occurs at 1056 psig. Since the low-low set SRVs and the reactor high pressure scram logic are both safety related and single failure proof, reactor operation at the SRV overpressure setpoint of 1109 psig would not occur for design basis accidents and normal reactor transients. HPCI and RCIC technical specifications based on an RPV pressure of 1120 psig are adequate and no changes are needed.

Peak primary containment pressures actually decline slightly with rerate. While suppression pool temperatures do rise, the resultant temperatures are within the capabilities of pumps and valves that communicate with the suppression pool.

There were no mechanical components for which operability at the uprated power level could not be confirmed.

(Part 2.) The response to this question as it applies to MOVs is in progress and will be submitted at a later date.

24. *In reference to Section 3.13, list the balance-of-plant (BOP) piping systems that were evaluated for the power uprate. Discuss the methodology and assumptions used for evaluating BOP piping, components, and pipe supports, nozzles, penetrations, guides, valves, pumps, heat exchangers and anchors. Were the analytical computer codes used in the evaluation different from those used in the original design-basis*

analysis? If so, identify the new codes and provide justification for using the new codes and state how the codes were qualified for such applications.

NSP Response

Balance-of-plant piping (BOP) was reviewed to determine the impact of power rerate on plant piping and equipment. The following BOP piping systems were determined to be affected by power rerate.

Main Steam
Residual Heat Removal
High Pressure Coolant Injection
Reactor Core Isolation Cooling
Feedwater
Condensate
Feedwater Heater Piping
Emergency Service Water
RHR Service Water
Service Water
Fuel Pool Cooling & Cleanup
Reactor Building Closed Cooling Water
Miscellaneous Steam Piping Including Extraction Steam and Turbine Moisture Separator Piping
Circulating Water

Evaluation of those portions of BOP piping attached to the torus, torus penetrations, and valves and pumps that may be affected by Mark I containment hydrodynamic loads as well as peak suppression pool temperature is discussed in the response to Question 26.

The increase in temperature, pressure, and flow due to power rerate was determined for the affected BOP piping. Piping and supports were evaluated in accordance with requirements of USAR Section 12. The results show that all piping and all but a few pipe supports are within the applicable code allowable limits under rerate conditions (See response to Question 25 for applicable codes). Minor modifications to supports are required as described in the response to Question 30.

All safety related piping and some non-safety related piping was analyzed using the licensing basis computer code. Piping evaluations were performed using the PISTAR program which was approved for piping applications by a Staff Safety Evaluation Report (SER) dated September 11, 1985. Piping was analyzed for deadweight, pressure, thermal expansion and Safe Shutdown Earthquake (SSE) loads in accordance with USAR Section 12. Pipe supports were qualified per applicable codes and standards. Examples of non-safety related piping systems analyzed in the above evaluation include main steam, RCIC, feedwater, portions of condensate, fuel pool cooling & cleanup, and service water. Certain system piping is not affected by power rerate conditions. The impact of power rerate on RBCCW and circulating water systems was determined to be insignificant.

The remaining non-safety related piping was evaluated using the Algor PipePlus computer code or by using comparative evaluations. The Algor PipePlus computer program was used to analyze portions of condensate piping, feedwater heater/cooler associated piping, and turbine extraction steam piping. Piping was analyzed for deadweight, pressure, and thermal expansion in accordance with USAR Section 12. The Algor computer code was procured from Algor Inc. with the trade name of PipePlus as QA software for analysis of safety related piping systems. Algor Interactive Systems, Inc. has verified the adequacy of PipePlus by comparing results with the NUREG/CR-1677 benchmark, which provides the confidence to justify its use as a piping analysis tool for rerate.

The remaining condensate, feedwater heater/cooler associated piping, turbine extraction steam and turbine moisture separator piping was evaluated using comparative evaluations. This method of analyses was considered to be adequate since the increase in the above piping operating temperatures and pressures at rerated conditions is insignificant, and the existing pipe stress analyses show large margins exist in piping stresses and pipe support loads. The existing piping stresses were increased in proportion to the increase in piping temperatures and pressures at rerated conditions. The new calculated stresses were compared to the code allowables. Pipe supports were evaluated using a similar approach by comparing calculated support loads at power rerate and comparing them to the support design loads. Pipe stresses were found to be within the code limits. Support loads were found to be within the original support design loads. The results show that significant margin exists in piping and supports at rerated conditions.

Equipment nozzles were evaluated to ensure that the calculated piping reaction loads under rerate conditions are less than the piping reaction loads from the original design analysis or less than manufacturer-specified allowables. In some cases where nozzle allowable loads were not available, certain non-safety related nozzles were qualified using standard analytical methods such as generally accepted formulae for cylindrical shells with attachments. Torus penetrations were qualified in accordance with the requirements of NUREG-0661 and the ASME Code, Section III as identified in Section 12 of the USAR. All equipment nozzles were found acceptable for power rerate conditions. Design pressure and temperature ratings for pumps, valves and heat exchangers were found to envelope power rerate conditions.

25. *Provide the calculated maximum stresses for the critical BOP piping systems, the allowable limits, the code of record, and code edition used for the power uprate conditions. If different from the code of record, justify and reconcile the differences.*

<u>NSP Response</u>

The maximum pipe stress increases for BOP piping are shown in Table 3-5 of the power rerate license amendment request. The maximum piping stresses are below the code allowable limits as stated in USAR Section 12. The construction code for the original plant piping systems was USA Standard Code for Pressure Piping, Power Piping, USAS B31.1.0, 1967 edition. Plant piping that was affected by power rerate conditions was evaluated in accordance with ANSI B31.1, 1977 edition with Addenda up to and including Winter 1978 which meets or exceeds the requirements of the original code of construction. This code was used for evaluation of plant piping systems in response to IE Bulletin 79-14. The allowable stress limits are in accordance with ANSI B31.1 for sustained, thermal, and occasional loads.

26. *Referring to Sections 3.6 and 4.1.2, provide the evaluation of piping systems attached to the torus shell, vent penetrations, pumps, and valves that may be affected by the LOCA dynamic loads (pool swell, condensation oscillation, and chugging) considered in the evaluation for the power uprate.*

<u>NSP Response</u>

Piping was analyzed in accordance with the requirements of NUREG-0661 as stated in USAR Section 12. NUREG-0661 established the ASME Code, Section III allowable stresses as acceptable stress limits for torus attached piping. The Staff's Safety Evaluation (SER) dated September 11, 1985 concluded that the original torus attached piping analyses, "Plant Unique Analysis Report" (PUAR) met the acceptance criteria contained in NUREG-0661. See NSP's letter to the staff dated August 12, 1997 regarding code reconciliations for certain Mark I analyses.

As stated in Section 4.1.2 of the power rerate license amendment request, Mark I containment hydrodynamic loads (e.g. pool swell, condensation oscillation, chugging) are not affected by power rerate. Thus the existing torus attached piping analyses for LOCA dynamic loads bound power rerate conditions. However, torus attached piping was evaluated for peak suppression pool temperatures under power rerate conditions. The results show all piping and supports are in compliance with the requirements of NUREG-0661 and the ASME Code stress limits.

Since LOCA dynamic loads are unchanged for power rerate, valve accelerations due to dynamic loads are bounded by the existing design values. Therefore operability of valves is not affected. Valve and pump pressures and temperatures are within valve and pump design values.

27. *In reference to Section 3.8.2, provide a detailed discussion of the effects of the steam flow increase, identified in Table 1-2, on the design-basis analysis of the main steam piping due to main steam isolation valve (MSIV) closure and turbine stop valve (TSV) closure loads. Also, provide an evaluation of MSIV structural integrity and functionality due to the increase in the hydraulic pressure for the higher flow rate following the power uprate, as discussed in Section 4.7 of GE's Generic Evaluations of General Electric*

Boiling Water Reactor Extended Power Uprate (NEDC-32523P) (proprietary information - not publicly available).

NSP Response

(Part 1) Effects of Steam Flow Increase

The design-basis analysis of the main steam piping considered dynamic loads due to closure of the main turbine stop valves. The loads created by operation of the main turbine stop valves are limiting and bound MSIV closure loads. For power rerate, the main steam temperature and pressure during normal operating conditions will remain unchanged. Thus the increase in the main stop valve closure loads is directly proportional to the increase in the main steam flow. For power rerate operation at 1775 MWt, the increase in main steam flow is 7.1% as shown in Table 1-2 of the rerate amendment request. For the analysis of main steam piping and pipe supports, an increase in main steam flow of 14.4% corresponding to a reactor thermal power of 1880 MWt was used. The original design-basis forcing functions for main turbine stop valve closure loads were increased by 14.4%. The new forcing functions were applied to the main steam lines including main steam, main steam equalizing and main steam bypass lines, inside and outside containment. The piping models included the attached SRV discharge piping, the HPCI steam lines, and the RCIC steam lines. This analysis methodology was consistent with the original main steam piping analyses. The results show all piping and pipe supports are within the code stress limits as identified in USAR Section 12.

(Part 2) MSIV Impact

As stated in Section 3.8.2 of Exhibit E of the rerate license amendment request, the maximum flow and differential pressure that the MSIVs are required to close against during a steam line break will not change under power rerate. This is because the maximum steam flow and differential pressure are dependent on maximum reactor dome pressure and main steam line venturi design which are not being changed for power rerate. Therefore, power rerate will not result in an increase in main steam maximum hydraulic pressure so MSIV structural integrity and functionality are unaffected.

28. *Discuss the potential for flow-induced vibration in the heat exchangers following the power uprate.*

NSP Response

No safety related heat exchangers will experience increased flows under rerate conditions. No increased flow will be required by emergency core cooling systems or containment cooling systems. Thus no safety related heat exchangers will experience potential flow-induced vibration.

The reactor building closed cooling water system, reactor water cleanup system and fuel pool cooling system flows are not required to increase under rerate operating conditions. Only heat exchangers on the condensate and feedwater systems will be subject to increased flow under rerate operation. These systems are not safety related. The impact of increased flow in the condensate and feedwater system is addressed in the response to question 29.

29. *In reference to Section 7.4, provide the evaluation of the feedwater heater for the power uprate with regard to vibration, stress, and fatigue usage.*

NSP Response

The feedwater heaters have been evaluated by the original equipment manufacturers (OEM) for increased stresses resulting from operation at higher temperature and pressure. The evaluations were performed to the original code of construction for each heater. The code year and addenda vary due to replacement of several heaters over the life of the plant but all are designed and constructed to ASME Code Section VIII Division 1 and Heat Exchanger Institute (HEI) standards. The results of the evaluations show all feedwater heat exchangers are within the applicable code allowable limits.

ASME Section VIII, Division 2, paragraph AD-160, states that it is the users responsibility to determine whether a fatigue usage evaluation is required. Since all of the feedwater heaters are designed to Division 1, the fatigue usage evaluation does not apply. ASME Section VIII Division 1 provides appropriate design safety factors to justify not performing a fatigue evaluation.

An evaluation of the feedwater heaters for vibration effects has also been performed by the OEMs and operation at rerate conditions is considered to be acceptable.

Given the above, power rerate will not require any physical modifications to the feedwater heaters. In addition, it is important to note that there is no safety impact associated with this equipment.

30. *In Exhibit D, the statement is made that modification to piping or equipment supports for some plant systems due to load changes involves approximately 12 pipe supports. Provide examples of pipe supports requiring modification and discuss the nature of these modifications.*

NSP Response

Piping support modifications due to load changes are described below.

- One spring hanger on a feedwater heater drain line will be replaced with a rigid support.
- The RHR heat exchanger supports require minor modifications to base plates.
- Non-safety related drain lines from each main steam line to the condenser were evaluated to ensure that a qualified path for MSIV leakage to the condenser exists during a seismic event. All drain lines and equipment within the scope of this evaluation were seismically verified. The evaluations show several new supports and modifications to the existing piping and equipment supports are required in order to limit piping displacements and to increase load carrying capacity of supports during a seismic event.

These modifications will be completed prior to startup at rerate conditions. The formal commitment will be documented in NSP's revised license amendment request.

Human Factors

31. *Discuss whether the power uprate will change the type and scope of plant emergency and abnormal operating procedures. Will the power uprate change the type, scope, and nature of operator actions needed for accident mitigation and will it require any new operator actions?*

NSP Response

For power rerate, reliance will continue to be placed on symptom-based Emergency Operating Procedures. As such, the type, scope, and nature of operator actions needed for accident mitigation remains unchanged. PRA analysis has determined that no new operator actions are required. Some operator actions require reduced response times in select scenarios. See NSP response to Question 32 below.

32. *Provide examples of operator actions potentially sensitive to power uprate and address whether the power uprate will have any effect on operator reliability or performance. Identify operator actions that would necessitate reduced response times associated with a power uprate. Please specify the expected response times before the power uprate and the reduced response times. What have simulator observations shown relative to operator response times for operator actions that are potentially sensitive to power uprate. Please state why reduced operator response times are needed. Please state whether reduced time available to the operator due to the power uprate will significantly affect the operator's ability to complete manual actions in the times required.*

NSP Response

Section 10.5.3 of NEDC-32546P discusses many of the above topics in detail as it describes the results of PRA analyses performed for the requested power uprate. These PRA analyses were performed at a bounding 12% higher power level (1870 compared to 1670 MWt), and thus incorporate additional conservatism compared to expected results for the requested power uprate to 1775 MWt.

The underlying physical phenomena driving essentially all observed changes in required operator actions are the approximately 12% higher decay heat and the corresponding ATWS power levels. Any postulated sequence of events leading to core damage driven by these higher power levels and dependent upon intervening operator actions are impacted by the higher power levels. The referenced PRA calculations utilized screening methodology to determine for what events these power levels and the human actions to mitigate the effects of the changed power levels were important, then determined what the new required time for operator actions was to ensure equivalent prevention of core damage, then input these new operator action times into a human reliability analysis to determine the increased chance of failure of the required operation action(s), and then finally input these changes in operator action success probabilities to calculate changes in the overall Core Damage Frequency (CDF).

In regard to operator actions, no changes to assumed operator actions for design basis event mitigation is required. Operator actions affected by rerate are those required for severe accidents and for those events outside the plant's design basis but within the licensing basis. Examples of the operator actions most sensitive to power rerate include: (1) manually depressurizing the reactor vessel, and (2) injecting boron with the Standby Boron Liquid Control (SBLC) system. Several other operator actions show significantly less sensitivity to power rerate and include: (1) restoration of power during a Station Black Out, (2) recovery of emergency diesel generators, and (3) repair of failed plant equipment prior to exceeding allowed primary containment pressure limits or vessel water level dropping below 2/3 core height.

Section 10.5.4 of NEDC-32546P (Exhibit E of the license amendment request) discussed examples of the changes in required operator response times before and after the bounding 12% power rerate. About 2/3 of the increase in Core Damage Frequency due to the power rerate arises from high pressure core damage sequences characterized by high pressure injection system failure after a successful reactor scram and subsequent failure to depressurize the reactor to allow low pressure makeup. It was noted that the required time to initiate manual depressurization of the reactor vessel was changed from 26 minutes to 23 minutes. Initiation of this manual action prevents water level from dropping below the top of active fuel. The shorter time allowed to complete the required action is driven by the 12% higher decay heat. Similarly, about 1/3 of the increase in Core Damage Frequency arises from failure to inject boron with the SBLC system during various ATWS scenarios. The ATWS scenario for which the time required to initiate SBLC changes most is an ATWS with feedwater continuing to operate (thereby sustaining a higher reactor power level) and no isolation from the main condenser. Energy is deposited to primary containment due to Monticello's relatively small (14-15%) turbine bypass valve capacity. The time required to initiate SBLC changes from 21 minutes to about 13 minutes. Initiation of SBLC prevents the suppression pool temperature from exceeding 260 °F. The shorter time allowed to initiate SBLC is driven by the higher ATWS power resulting from the bounding 12% power level.

Although required times to accomplish manual operator actions are decreased as illustrated above, there is still adequate time to accomplish these actions, and an expectation that the actions would indeed be accomplished. Operators are rigorously trained and evaluated on the symptom-based emergency operating procedures utilizing the Monticello simulator. Input of the somewhat shorter response times and the resultant somewhat higher human error probabilities results in a minor effect on the overall Core Damage Frequency. Section 10.5.7 of NSP's previous rerate license amendment confirmed that the change in Core Damage Frequency was minor by comparison with appropriate quantitative screening criteria.

33. *Discuss any changes the power uprate will have on control room instruments, alarms, and displays. Are zone markings on meters changed (e.g., normal range, marginal range, and out-of-tolerance range)?*

NSP Response

In regard to human factors, the main control room panel instrumentation, as presently configured, can support power rerate operation without modification. No changes to zone markings have been identified. Certain changes to instrumentation, such as setpoint changes, will be necessary. See Exhibit D of the license amendment request amendment and NSP's responses to questions 34 and 37.

34. *Discuss any changes the power uprate will have on the Safety Parameter Display System (SPDS).*

NSP Response

The impact of power rerate on SPDS, as well as other portions of the process computer and core monitoring software, is limited. Calculations and outputs that utilize power expressed absolutely in MWt are expected to continue to function with only minor adjustments in data validity checks to accommodate the higher expected MWt value when operating at 100% of rerated power. Some calculations that calculate power as a percentage of rated power will require that new databank values be loaded for the rated power value of 1775 MWt that appears in the denominator of such calculations.

Validation calculations currently exist that check reactor thermal power by performing alternate calculations based on plant parameters that are independent of the primary feedwater flow nozzles. The input range of the validation calculations be extended to accommodate operation at the higher rerated power level. Operation at a higher turbine-generator electrical output will require adjustments in data validity checks in this area. Thermal margin limits for core operation that are a function of reactor power and are monitored by core monitoring software (e.g. 3D-Monicore) will be reviewed as part of the normal core reload process to ensure that they are applicable to operation at 1775 MWt.

Prior to implementation of power rerate, all affected SPDS data points will be validated. The formal commitment will be documented in NSP's revised license amendment request.

35. *Describe any changes the power uprate will have on the operator training program and the plant simulator.*

Provide a copy of the post-modification test report (or test abstracts) to document and support the effectiveness of simulator changes as required by ANSI/ANS 3.5-1985, Section 5.4.1. Specifically, please propose a license condition and/or commitments that address the following:

(a) Provide classroom and simulator training on the power uprate modification.

(b) Complete simulator changes that are consistent with ANSI/ANS 3.5-1985. Simulator fidelity will be re-validated in accordance with ANSI/ANS 3.5-1985, Section 5.4.1, "Simulator Performance Testing." Simulator revalidation will include comparison of individual simulated systems and components and simulated integrated plant steady state and transient performance with reference plant responses using similar startup test procedures.

(c) Complete control room and plant process computer system changes as a result of the power uprate.

(d) Modify training and plant simulator relative to issues and discrepancies identified during the startup testing program.

NSP Response

a) Classroom and simulator training on new knowledge and abilities associated with the power rerate will be provided to all operations and licensed personnel in accordance with Monticello Training Center procedures. This training will be completed prior to implementation of power rerate.

b) Simulator changes will be completed in accordance with ANSI/ANS 3.5 - 1985 section 5.4.1 simulator performance testing and Monticello simulator configuration control procedures. Initial simulator changes will be completed prior to power uprate and verified against actual plant startup data.

c) See Question 34 above.

d) Training and simulator will be modified in accordance with applicable Monticello Training Center procedures to reflect issues and discrepancies identified during startup testing.

The formal commitments to these conditions will be documented in NSP's revised license amendment request.

Instrumentation and Controls

36. *For power uprates, the GE setpoint methodology discussed in GE topical report NEDE-31366 has been used to determine instrument setpoints. Therefore, this methodology should be referenced in the basis section of the technical specifications.*

NSP Response

A statement similar to the following will be added to the MNGP Technical Specification Bases related to section 3.1, "Reactor Protection System," and 3.2, "Protective Instrumentation."

> GE setpoint methodology provided in NEDC 31336, "General Electric Setpoint Methodology" is used, as applicable, in establishing setpoints.

The formal commitment will be contained in the revised license amendment request.

37. *The submittal does not address the effect of power uprate on instrumentation range/span. Also, Section 5.2.1, Control Systems Evaluation, states that, "process control valves and instrumentation have been evaluated for range and adjustment capability for use at the expected rerated condition. Any required changes will be performed prior to operation at the rerate..." However, the submittal does not identify any such instrumentation and control valves. Provide this information for staff review.*

NSP Response

The capacity of the turbine control valve has been analyzed and will be verified during rerate startup testing. Refer to rerate report GE-NE-L120082901, "Rerate Test Program Recommendations for the Monticello Nuclear Generating Plant." (Proprietary, available for inspection onsite.) The instrumentation and control valves requiring adjustment and modification are identified in Exhibit D of the license amendment request.

Review of the individual systems affected by rerate included the affect on instrumentation and controls. No instrument changeouts have been identified.

38. *Table 5-1 provides changes in the analytical limit for setpoints for the current and power uprate condition. The justification for these changes is based on the assumption that they do not increase the probability and consequences of postulated accidents, or reduce significantly the margin of safety. In order for the staff to arrive at the same conclusion, information is needed on instrument setpoints and allowable values in addition to the analytical limit for the instrumentation identified in Table 5-1 at both the current and uprate power conditions.*

The requested information is provided in the table below.

	EXISTING (1670 MWt)	NEW (1775 MWt)
APRM Rod Block		
Setpoint	107.5%	107.5%
Allowable value	110%	110%
Analytical Limit	112%	112%
APRM Scram		
Setpoint	119.5%	119.5%
Allowable value	122%	122%
Analytical Limit	125%	125%
Vessel High Pressure		
Setpoint	1051 psig	1051 psig
Allowable value	1085 psig	1085 psig
Analytical Limit	1090 psig [1]	1091.5 psig
ATWS High Pressure ATWS		
Setpoint	1135 psig	1135 psig
Allowable value	1155 psig	1155 psig
Analytical Limit	1162 psig	1162 psig
SRV		
Setpoint (maximum)	1120 psig	1120 psig
Allowable value	1142.3 psig	1142.3 psig
Analytical limit [2]	1142.3 psig	1142.3 psig
Turbine 1st Stage [3]		
Setpoint	27%	27%
Allowable value	30%	30%
Analytical limit	45%	45%
Main Steam Line High Flow		
Setpoint	137.5%	137.5%
Allowable value	142%	142%
Analytical Limit	146%	146%
Condenser Low Vacuum[4]		
Setpoint	23.25" hg	22.25" hg
Allowable value	22.5" hg	21.65" hg
Analytical	22.5" hg	21.5" hg

Notes

1. Changed due to setpoint methodology improvement independent of rerate.
2. A maximum reactor pressure of 1279 psia will result with the SRVs set at their analytical limit. The maximum allowable reactor pressure is 1350 psia.
3. The final relation between turbine 1st stage pressure in psig and % power will be determined during startup testing. The setpoint in psig will be set at a value less than 30% power by an amount determined by the setpoint methodology (approx. 3%).
4. Change supported by NSP's license amendment request.

Radiation Protection

39. *Section 8.5.2 of Exhibit E states that "NSP has established successful cobalt reduction, zinc injection, and hydrogen water chemistry programs. These programs and other dose reduction programs will adequately compensate for the possible increases in individual doses due to power rerate." Provide additional information concerning these dose reduction programs, state when these programs were implemented at Monticello, and describe what effect they have had on reducing overall doses at Monticello. Compare the estimated annual reduction in overall doses resulting from the implementation of these dose reduction programs with the estimated annual increase in doses at Monticello due to the proposed power rerate.*

NSP Response

Part I. Information Concerning Dose Reduction Programs

A. Cobalt Reduction Program

Description

The cobalt reduction program is a formal effort, consistent with the ALARA philosophy, to eliminate sources of stable Co-59 in plant systems which communicate with the primary system. The goal is to minimize the production of radioactive Co-60. To facilitate this effort, Co-59 sources have been identified and ranked according to the estimated Co-59 release rate.

Implementation

Cobalt reduction started in about 1982, when the first non-stellite control blades were installed for testing. Since then, the majority of originally installed high cobalt blades have been removed from the reactor. Other activities include replacement of numerous valves, drain lines, and high erosion surfaces on turbine blading and inner casings.

B. Zinc Injection

Description

Studies performed by General Electric show that small concentrations of zinc in the reactor water will result in a reduction in the amount of Co-60 incorporated into the oxide film established on stainless steel piping. This reduction in Co-60 incorporation provides substantial reductions in dose rates, particularly in primary containment. When first introduced, zinc injection utilized natural zinc. Later, it was determined that zinc depleted of the isotope Zn-64 was a better choice because it eliminated the problems associated with Zn-65, which is produced by neutron activation of Zn-64.

Implementation

Zinc injection was implemented in 1989. In 1993, injection of natural zinc was terminated in favor of depleted zinc.

C. Hydrogen Water Chemistry

Description

The presence of oxygen generated by radiolytic decomposition of water produces an environment favoring IGSCC of the components exposed to coolant. This mode of degradation can be controlled by suppressing the dissolved oxygen concentration with hydrogen injection and by maintaining high purity reactor coolant water. This process is called Hydrogen Water Chemistry (HWC).

Implementation

Hydrogen Water Chemistry was implemented in 1989.

D. Effects of Dose Reduction Programs

It is difficult to separate the effects of cobalt reduction and zinc injection because both programs have the same result, i.e., reduction of Co-60 concentrations on out-of-core surfaces. The combined effect is evident from the average concentration of Co-60 in reactor coolant, which has been decreasing since 1991. This is significant because the opposite was true over the five fuel cycles prior to that time. The decreased coolant concentrations have resulted in less deposition in recirculation piping, lower exposure rates in the drywell, and lower personnel doses. Based on average drywell exposure rates since 1993 and recorded personnel doses, it is estimated that dose saved during outages over the last two fuel cycles is in excess of 150 person-rem.

The benefits of the Hydrogen Water Chemistry (HWC) program are less evident. An immediate effect of HWC is increased dose rates in certain areas of the plant. Injecting hydrogen into reactor water increases the fraction of volatile N-16, which is carried over in the steam. As a result, dose rates due to primary steam increase approximately 3 to 5 times normal. The long term benefit which must be considered, however, is avoidance of the personnel dose that would be required to repair or replace reactor internals.

In an effort to offset the effect of increased dose rates due to N-16, routine plant practices and policies were examined and changed where appropriate to keep personnel exposure ALARA. Changes included reduced frequencies for some inspections and a practice of reducing the rate of hydrogen injection periodically to accomplish work in steam-affected areas. The net effect has been an overall reduction in personnel doses during operating periods. Comparison of average annual personnel dose outside of refueling outages, prior to and following HWC implementation, shows a decrease from 121 rem per year (1986 through 1988) to 81 rem per year (1989 through 1996). Not all of this decrease can be attributed to the actions taken to compensate for N-16 increases, but it is clear that the potential personnel dose increases were adequately offset.

Part II. Estimated Annual Dose Reductions vs. Increase

On an annual basis, the reduction in overall dose due to dose reduction programs is estimated to be 75 person-rem. This number is based on the following assumptions.

- Two year operating cycles
- Drywell dose is comparable to recent refueling outages (150 person-rem per outage)
- 1993 average drywell exposure rate (272 mR/hr)
- Current average drywell exposure rate (138 mR/hr which is about 50% of base rate)

Dose w/o dose reduction programs:	300 rem	(150 rem per outage ÷ 50% reduction)
Dose with dose reduction programs:	150 rem	(assumed average outage)
Annual overall dose reduction:	75 rem	(150 rem/outage ÷ 2 years/outage)

The estimated increase in drywell dose rates at Monticello due to the proposed power rerate to 1880 MWt is 8%. (See NEDC-32647, Monticello Cobalt Transport and Shutdown Drywell Dose Rate Model Calculation Results, attached.) Since Co-60 and other activated corrosion products are the source of more than 90% of drywell dose and because Co-60 and other activation products account for the largest portion of doses outside of the drywell, it is safe to assume that annual doses due to the proposed power increase will increase by approximately 10% overall. Since 1988, average annual dose for non-outage years has been 90 rem. The average dose for outage years (conservatively based on last two outage years) has been 315 rem. Therefore, the annual dose increase due to rerate is about 20 person-rem per year.

Average non-outage year:	90 rem	(1988 through 1996)
Average outage year:	315 rem	(1994 and 1996)
Two-year total:	405 rem	
Annual average total:	202 rem	
10% increase:	20 rem	

Given the above, the expected dose increase from power rerate of 20 rem/yr is more than offset by dose reduction programs.

40. *Section 8.4.2 of Exhibit E states that the power rerate may result in a net increase in the activated corrosion product production due to the increase in activation rate in the reactor region combined with the decrease in filter efficiency of the condensate demineralizers (due to the feedwater flow increase). Describe the magnitude of the estimated increase in activated corrosion products in the reactor piping and describe how this will affect dose rates in the vicinity of this piping. Describe any plans (such as increasing the amount of zinc injection to the reactor coolant system) that you may have to reduce the increased amounts of activated corrosion products in the piping caused by the proposed power rerate.*

NSP Response

Monticello analyzed the potential increase in activation products that may occur as a result of the reactor power rerate. This analysis is documented in GE Report NEDC-32647, Monticello Cobalt Transport and Shutdown Drywell Dose Rate Model Calculation Results - Final Report. The cobalt transport model developed by CC Lin (GE) has become a widely recognized and accepted algorithm for such modeling.

Power uprate affects the reactor system in the following ways.

1. Increased feedwater flow rate resulting in increased mass transport of feedwater impurities.
2. Increased core average neutron flux resulting in more activation events.
3. Increased heat flux on fuel surfaces resulting in higher corrosion product deposition.
4. Increased feedwater impurity levels due to increased feedwater flow conditions and reduced efficiency in condensate treatment systems.

At Monticello's direction, GE modeled rerate conditions for both 6.3 and 12.6% power rerate conditions. The overwhelming contributor to dose at Monticello is the isotope cobalt-60. This being the case, the cobalt transport model is very appropriate to use in determining the effect power rerate may have on dose rate buildup of recirculation piping. The GE model was run for a number of cases. A base case was run to provide a benchmark from which to judge the results of the other cases. The base case input parameters were chemistry parameters and conditions during calendar year 1996. The following parameters were used as model inputs: zinc injection is considered, reactor power is 1670 MWt, reactor conductivity was assumed to be 0.114 uS/cm, feedwater iron was assumed to be 1.4 ppb, and feedwater cobalt concentrations were assumed to be 3 ppt. The results of the power rerate cases predict potential increases in Co60 relative to the base case. Modeling indicates a power rerate of 6.3 % (1775 MWt) may result in an increase in Co60 activity and dose rate of 2-4% through EOC-22. For a power level of 12.6% (1880 MWt), an increase of 8-13% both in Co60 activity and dose rate is predicted. To put these values in perspective, the 6.3% and 12.6% power increases would result in recirc piping dose rate increases of 3 mr/hr and 13 mr/hr respectively. From a radiation protection perspective these low level increases are quite manageable.

There are several factors that will likely reduce or negate the predicted dose rate buildup increases resulting from power rerate. Feedwater iron reduction efforts have been very successful to date. In the Cobalt Transport model study the base case assumed a feedwater iron concentration of 1.4 ppb. Modeling shows an overall reduction in recirc piping dose rates of 14% through EOC-22 for feedwater iron concentrations around 0.5 ppb. The average feedwater iron concentration for cycle 18 is about 0.8 ppb. Also, a significant reduction in cobalt source term should be evident with the changeout of the high and low pressure turbines during the 1996 refueling outage. The original turbine had stellite faced blades at the latter stages of the LP turbine. The new turbine does not use stellite but rather employs a flame hardening technique to provide the needed hardness to protect against moisture impingement. It is estimated that reductions in feedwater cobalt may achieve a dose rate reduction of 8% through EOC-22.

The injection of depleted zinc oxide (DZO) at Monticello has been demonstrated to effectively reduce recirc piping dose rate buildup. The DZO injection rate is varied depending primarily on the soluble Co60 concentration trend in the reactor coolant. Other parameters are considered as well, however the direct link between reactor coolant Co60 concentrations and recirc pipe dose rates are widely accepted and well established. Should Co60 concentrations increase as a result of power rerate implementation DZO injection rates will be altered accordingly while considering all available parameters.

41. *Section II.H.3.b of Exhibit A states that "Reference to containment spray is to be deleted from this discussion." Provide your reasons for not taking credit for containment spray and state whether deleting reference to the containment spray in this section constitutes a change in your accident dose analysis.*

NSP Response

There are no design basis event sequences that rely on containment sprays for accident mitigation. In some severe accident scenarios, the use of containment spray is credited. Containment spray operation was postulated in the development of certain EQ profiles. The use of containment sprays is a general enhancement of safety such that NSP has decided to retain this credit. Section II.H.3.b will be amended to reflect this change.

42. *Exhibit D (p.D-1) states that one of the hardware changes for power rerate will be to modify the Control Room Emergency Filtration Train system "to reduce control room ventilation filter bypass leakage to establish consistency with control room dose calculation inputs." Discuss what you mean by establishing "consistency with control room dose calculational inputs." In Table 9.4 of Exhibit E you state that the estimated thyroid dose in the control room following a LOCA at the rerate power of 1880 MWt would be 13 rem. State what the estimated LOCA thyroid dose in the control room would be (at 1880 MWt) if the control room ventilation filter bypass leakage were not reduced. Provide both the current and the reduced control room bypass leakage figures in cubic feet per minute.*

NSP Response

Under the current dose calculations (NSP Calculation 94-009 Revision 1, dated 7/22/94), an inleakage of 500 cfm is assumed for the first 8 hours of the accident. After 8 hours, ingress and egress into the control room would be restored back to normal levels and positive pressure will be assured. The inleakage used in the calculation then drops to an assumed 250 cfm for the duration of the accident. This inleakage is due to 240 cfm of leakage across the inlet isolation dampers on the operating CRV train and an additional 10 cfm from normal ingress and egress from the control room. This calculation used 90% for the Standby Gas Treatment and the Control Room filter efficiencies and 90% plateout of iodine in the steam lines and in the main condenser.

Preliminary work performed for the rerate effort showed that with an inleakage of 500 cfm for T<8 hours and inleakage of 250 cfm for T>8 hours, control room operator dose to the thyroid would be 38 rem. This work was done as a preliminary sensitivity study and was never finalized. It used a SBGT efficiency of 81% and an control room filtration efficiency of 95%. It also used the new BWROG methodology for modeling iodine plateout in the steam line and the condenser (GE Report NEDC-31858P).

To limit the dose to less than 30 rem, inleakage from the inlet isolation dampers had to be reduced or eliminated and credited filter efficiencies increased. GE performed the dose calculation for the rerate condition. Under this analysis, control room inleakage was 250 cfm for T<8 hours and 10 cfm for T>8 hours. Standby Gas Treatment and Control Room filter efficiencies were changed to 85% and 98% respectively. This model used the BWROG method for modeling iodine plateout in the stream line and the condenser provided in NEDC-31858P.

To ensure no inleakage for the control room ventilation inlet dampers, blanking plates were installed on the system in August of 1996. Dedication of the main steam system and condenser to meet the requirements of NEDC-31858P is being done under other parts of the same modification.

43. *Exhibit A (p.A-21) states that, based on a radiological analysis for the proposed rerate, you will improve the efficiencies of the control room emergency filtration system filter and the standby gas treatment system filter. State the current and proposed filter efficiencies and discuss your timetable for making these changes.*

NSP Response

The current and proposed filter efficiencies are summarized below.

Control Room Filters		*Standby Gas Treatment Filters*	
Current	*Proposed*	*Current*	*Proposed*
90%	*98%*	*90%*	*85%*

As stated in paragraph 4, page A-21 of Exhibit A to the license amendment, the credited overall efficiency of the filters in the Standby Gas Treatment system actually will be decreased. Reducing the efficiency credited in the SBGT system provides additional margin for filter bypass.

A license amendment request entitled, "Reactor Coolant Equivalent Radioiodine Concentration and Control Room Habitability," was submitted on July 26, 1996. Revision one to this LAR was submitted on April 11, 1997 and supersedes the original submittal in its entirety. This submittal supports the acceptance criteria for the control room filtration system efficiencies indicated above. The procedure which governs control room filter testing has been changed to incorporate the more restrictive acceptance criteria. Review of past testing results indicates that these criteria can be satisfied.

44. *The table on page A-20 of Exhibit A lists the calculated potential offsite doses at the exclusion area boundary (EAB) and low-population zone (LPZ) from the following design-basis accidents: loss of coolant, refueling, control rod drop, and steamline break. These doses were calculate by the AEC staff and are contained in the staff safety evaluation dated March 18, 1970.*

a. For the same four accidents described above, provide a listing of the postulated doses (both whole body and thyroid) at the EAB, LPZ, and control room that were calculated by the licensee during the initial licensing of the plant.

On page A-21 of Exhibit A, you state that the inputs and evaluation methods for the MNGP power rerate differ from those used in the current licensing basis evaluation contained in the USAR and in the AEC safety evaluation. You state that you have established dose multipliers that should be used to multiply the doses contained in your original licensing basis evaluation to obtain the does calculated for the MNGP power rerate.

b. Show how you applied these dose multipliers (listed in Table 14.7-22 of the USAR) to the doses calculated using your current licensing basis evaluation to arrive at the revised accident doses for the proposed power rerate (listed in Table 9-4 (Appendix E) of the rerate licensing amendment request).

NSP Response

Part a.

Postulated accident doses calculated during the initial licensing of the Monticello plant are presented in Section 14.6 of the original Monticello Final Safety Analysis Report (FSAR). This is now Section 14.7 of the Monticello Updated Safety Analysis Report (USAR). These analyses were performed using the methods described in General Electric topical report APED 5756, "Analytical Methods for Evaluating the Radiological Aspects of the General Electric Boiling Water Reactor," March, 1969.

The FSAR dose calculations generally used more realistic assumptions than those used by the AEC Staff. For example, TID-14844 source terms were not used in the loss of coolant accident radiological analysis. In addition, the methodology for atmospheric dispersion calculations differed significantly from methods used by the AEC and those currently in use.

Control room doses were not calculated in the FSAR. The original licensing and design basis for the Monticello plant predated 10 CFR Part 50, Appendix A, GDC 19. A safety grade control room filtered air supply system was later added to the plant in response to the NRC Three Mile Island Action Plan, and dose calculations were completed in 1981 to demonstrate conformance to GDC 19 using the existing NRC guidance.

The original FSAR accident dose calculations are presented in the table below.

ACCIDENT	LOCATION	WHOLE BODY DOSE (REM)	THYROID DOSE (REM)
LOSS OF COOLANT	EAB (1/3 MILE)	5.8E-4	5.2E-5
	LPZ (1 MILE)	3.6E-4	4.2E-5
	CONTROL ROOM	----------	----------
REFUELING	EAB (1/3 MILE)	7.0E-3	3.0E-3
	LPZ	4.4E-3	3.0E-3
	CONTROL ROOM	----------	----------
CONTROL ROD DROP	EAB (1/3 MILE)	5.2E-3	3.4E-4
	LPZ (1 MILE)	4.6E-3	2.8E-4
	CONTROL ROOM	----------	----------
STEAM LINE BREAK	EAB (1/3 MILE)	4.5E-3	2.0
	LPZ (1 MILE)	3.0E-3	1.0
	CONTROL ROOM	----------	----------

In Section 14.10 of the original Monticello FSAR (now Section 14.7.7 of the Monticello USAR), "Design Basis Accident Radiological Dose Multipliers" were presented which, when multiplied by the accident doses calculated in Section 14.6, would give results which more closely resemble doses calculated using AEC Division of Reactor Licensing (DRL) methodology. These "Dose Multipliers" are presented in Table 14-10-8 of the original FSAR (Table 14.7-22 of the USAR). They are reproduced below.

ACCIDENT	WHOLE BODY		THYROID	
	2-HOUR (500 M)	30-DAY (3218 M)	2-HOUR (500 M)	30-DAY (3218 M)
LOSS OF COOLANT	1.08E+02	1.96E+03	8.86E+05	6.00E+05
REFUELING	6.10E+01	4.51E+00	3.22E+02	2.50E+02
CONTROL ROD DROP	2.89E+00	3.03E+00	8.94E+04	4.56E+04
STEAM LINE BREAK	1.00E+01	----------	5.71E+01	----------

The original dose calculations and the "Dose Multipliers" presented in the FSAR and USAR are not consistent with current updated NRC guidance and were not used for power rerate analyses.

Part b.

The "Dose Multipliers" described in response (a) above were used only in the original accident radiological analyses performed for the Monticello plant. They were not used to arrive at the revised accident doses for the proposed power rerate.

Plant specific accident dose analyses for Monticello power rerate were calculated by General Electric in accordance with current NRC guidance using a reactor thermal power of 1880 MWt. These calculations are described in Section 9.2 of Appendix E of the Monticello rerate license amendment request.

Dose analyses were also performed using the same current methods at the existing licensed power of 1670 MWt. Table 9-4 of Appendix E of the Monticello rerate license amendment request compares calculated accident doses at the existing licensed power level of 1670 MWt to those calculated at the analyzed rerate power level of 1880 MWt.

A comparison of accident dose calculations at rerate power level using currently approved methods to doses calculated at 1670 MWt in the FSAR and USAR would provide inconsistent results and would not be meaningful in the context of the current methodology.

Following NRC approval of rerate power operation at Monticello, the USAR will be updated to reflect the new radiological analyses performed by General Electric using currently approved methods. These analyses employ methods previously approved by the NRC and are available for inspection onsite.

A formal and more encompassing commitment to update the USAR will be made in NSP's revised rerate license amendment request.

45. *Describe those plant changes (both operational and hardware changes) made to accommodate the proposed power rerate that will have an effect on the calculated EAB, LPZ, and control room doses following any one of the following design-basis accidents: loss-of-cooling, refueling, control rod drop, and steamline break.*

NSP Response

Two basic hardware changes were performed to the plant in order to support radiological dose evaluations for the power rerate. The first change was the installation of blanking plates on the Control Room Ventilation System inlet ductwork. This will ensure that inleakage into the protective envelope from the isolation dampers is zero. This is consistent with the control room operator dose calculations used in the power rerate program.

The offsite and control room operator dose assessments used to support rerate use the BWROG methodology (GE Report NEDC-31858P) with regards to plateout in the main stream lines and the condenser. This required that the steam lines, steam line auxiliary piping, steam line drains and main condenser be verified to withstand a seismic event in accordance with the methodology. Doing this verification, a number of improvements and modifications to steam line auxiliary piping and drains were identified. These modifications included changing pipe from carbon steel to stainless steel to reduce corrosion/erosion concerns, changing and adding piping supports and eliminating a steam line drain loop seal to increase the effective size of the main condenser credited in the calculations.

Some operational changes have resulted from the Power Rerate program. As mentioned in question 43, the credited filter efficiencies of the Control Room Filtration System and the Standby Gas Treatment System have been changed. This required changing the acceptance criteria of these filters during normal surveillance tests. Because of the plates installed on the control room ventilation system, the filter trains run more often resulting in the testing of the charcoal beds as required by Technical Specifications after every 720 hours of operation. This increases the frequency of charcoal bed testing from once every 18 months in the past to about once every 6-9 months in the future.

The Technical Specification allowed dose equivalent iodine has been reduced from 5 microcuries/ml to 0.25 microcuries/ml. See NSP's license amendment request dated July 26, 1996 and revised on April 11, 1997, "Reactor Coolant Equivalent Radioiodine Concentration and Control Room Habitability."

46. *On page 10-8, the last paragraph states "rerate analysis did require two SRVs (safety-relief valves) to open to avoid reactor overpressure whereas only one SRV is adequate for the 100% power level case." How was this change reflected, if any, in the risk analysis and how (much) did it contribute toward the estimated increase in plant core damage frequency (CDF)?*

NSP Response

The likelihood of all eight SRVs failing is very similar to at least seven out of eight SRVs failing. The effect on the estimated CDF would be negligible so the PRA model was not modified to reflect the change in the SRV over pressure protection success criteria. This change was only addressed qualitatively.

47. *On page 10-9, 2nd paragraph under the section, "Time Available for Operator Action," states that "the most important post-initiator human errors were recalculated using the method described in NUREG/CR-4772 ["Accident Sequence Evaluation Program Human Reliability Analysis Procedure"] for deriving nominal human error probability estimates (ASEP [Accident Sequence Evaluation Program] method). Please describe the increase in human error rates of the most impacted operator actions due to the power rerate by providing their "current" human error rates as well as the "new" human error rates that were estimated using the above method.*

For example, on page 10-15, the first paragraph states 'the time for the operator to initiate SBLC is reduced from approximately 21 minutes to 13 minutes. In spite of the reduction in time to perform this action, the likelihood of the operator correctly performing this action is still high." Please provide the change in human error rates associated with the change in requirement to initiate SBLC from 21 minutes to 13 minutes and show how this change impacts the analysis results.

As another example, on page 10-14, the fourth paragraph states 'a large portion of the CDF due to high pressure core damage sequences result from internal flood initiator events." On page 10-15, the fourth paragraph states "this is due to the decrease in the time available for the operator to blowdown the vessel before the core becomes uncovered." How is two thirds (approximately 1.6E-6/Yr) of the CDF increase attributed to operators' ability to respond to these sequences?

Table 47-1 provides the "current" and "new" human error rates for the operator actions that could have the greatest impact on the change in CDF due to rerate. They are given in the columns called "base case" and "rerate". The human error rate associated with a change in the requirement to initiate SBLC from 21 minutes to 13 minutes is in the row with the Basic Event name SLCTOPY. Less than one third of the 17.5% change in CDF is due to this change.

Two thirds of the CDF increase occurs in high pressure core damage sequences and is due to the decrease in time available for the operator to depressurize the vessel. Although there is a relatively small decrease in time associated with this operator action, it is a sensitive parameter in the PRA model (operator action with the highest Birnbaum). Table 47-1 provides the "current" and "new" human error rates for failure to depressurize in the row for Basic Event XRPVBLDWNY. See the response to question 49 for more discussion on emergency depressurization.

Table 47-1 Important Internal Events HEPs

Basic Events	Description	Probability	
		Base Case	Rerate
XRPVBLDWNY	Operator fails to depressurize reactor for low pressure makeup	1.1E-3	1.4E-3
XRPV10	Operator fails to depressurize reactor in 10 minutes (Medium LOCA)	2.0E-2	2.6E-2
FRFPOPERAY	Failure to control feedwater after a scram	2.4E-3	2.4E-3
UH	Operator dilute boron by failing to control reactor water level	1.0E-2	1.0E-2
MCONVENTY	Operators fail to vent containment	3.0E-5	3.0E-5
SLCCOPY	Operator fails to initiate SLC during ATWS (Loss of Main Condenser)	2.4E-3	4.9E-3
SLCMOPY	Operator fails to initiate SLC during ATWS (MSIV closure - feedwater operates initially until hotwell low level)	2.4E-3	4.9E-3
SLCFOPY	Operator fails to initiate SLC during ATWS (MSIV closure - no feedwater)	2.0E-3	2.0E-3
SLCLOPY	Operator fails to initiate SLC during ATWS (LOSP event)	2.0E-3	2.0E-3
SLCTOPY	Operator fails to initiate SLC during ATWS (Turbine Trip with bypass)	4.4E-3	4.04E-2
NOOSP30	Failure to recover OSP in 30 minutes	0.64	0.66
NOOSP2	Conditional non recovery of OSP in 2 hours given no OSP recovery in 30 minutes	0.45	0.44
NOOSP6	Conditional non recovery of OSP in 6 hours given no OSP recovery in 30 minutes	0.16	0.153
NODG2	Failure to recover EDG in 2 hours	0.66	0.68
NODG6	Failure to recover EDG in 6 hours	0.35	0.36
ABKFDXXXXY	Failure to back feed DG13 to essential loads following loss of all AC sources	0.5	0.5
WREC48HRS	Failure to recover RB equipment (long term)	0.24	0.28

48. *On page 10-11, Section 10.5.3.2, "Internal Events PRA - Level 2 (Containment Analysis)," the first paragraph states that the requantified results of the Level 2 portion of the PRA update was not available at the time of this analysis. Please provide the quantitative results of the Level 2 analysis. If available, please also provide the quantitative results of the risk analysis for external events.*

NSP Response

Part 1 Quantitative Results of Level 2 Analysis

The results of the updated level 2 analysis for the Monticello PRA are summarized in Figure 48-1. Two means of binning the accident sequences of the Level 2 PRA are used in this figure. Plant damage states, defined in Table 48-1-1, establish the reactor status, containment failure mode, and containment failure timing (from an emergency planning perspective) of any sequence. Release modes, defined in Table 48-1-2, were used to categorize the accident sequences from the standpoint of magnitude of release. Consistent with the definition used in the implementation of the Maintenance Rule, the following was used to categorize large, early release sequences.

The term *Release* implies failure of containment to retain fission products following a core damage event in the form noble gases, volatiles (Cs/I) and non-volatiles (Te, Sr, etc.). The term *Early* refers to the timing of releases from containment relative to implementation of protective action guidelines associated with the emergency plan. For the purpose of this discussion, the definition of early releases is simplified to be those releases which occur before the offsite protective action recommendations under the emergency plan can be effectively implemented (i.e., approximately 6 hours after declaration of a general emergency). The term *Large* includes two aspects: the volumetric release rate and the amount of fission products released. Large releases are considered to occur only if the release path is sufficiently large that release rates would be significantly greater than those permitted by Technical Specifications, and if the release is not filtered through a pool of water or sprays to retain a significant fraction of the fission products inside containment.

Given these definitions, the accident sequences which are considered to lead to large early releases are those that are binned into release mode categories C4 through C12 which also have a timing plant damage state designation 'E' (for early). In addition, release mode categories E1 and E2, which represent bypass and containment isolation failure sequences, are considered to lead to large early releases.

From Figure 48-1, it can be seen that the majority of sequences do not fall in the large early release category either because they do not result in containment failure, they are vented or released through a pool, or they occur late, many hours into the accident. From the baseline Level 2 PRA results, the potential for a large early release therefore is small, on the order of 3% of the total core damage frequency. As with other Mark I containments, large early releases for Monticello are dominated by ATWS and interfacing LOCA sequences. Hydrogen combustion during accident sequences in which the containment is deinerted also contributes to early releases because a conservative assumption was made that periodic burns will not limit hydrogen concentration. The liner melt-through containment failure mode is not likely to occur at Monticello because the drywell sumps are large compared to the size of the core, so these sumps can retain most of the debris that would be released from the vessel at the time that the bottom head is breached by molten debris. The debris is therefore not expected to come in contact with the containment liner.

Following rerate, the sequences leading to large early releases rise roughly proportionally with the core damage frequency to remain at approximately 3% of the new core damage frequency. Virtually all of the changes in the Level 2 quantification are a result of the changes made to the Level 1 accident sequence analysis in the form of reduced time available for operator action in preventing core damage. ATWS sequences make up the bulk of the increase in large early releases due to the shorter time available to the operator to initiate standby liquid control and effect shutdown in the Level 1 portion of the quantification. Little modification to the Level 2 analysis was necessary. Only station blackout sequences were affected due to a slightly reduced amount of time available to recover offsite power. The major contributors to large early releases remain the same as indicated in the baseline analysis and include ATWS, hydrogen combustion, and interfacing LOCA sequences. As in the base case analysis, the majority of the Level 2 accident sequences either do not result in containment failure, are vented or released through a pool, or are estimated to occur many hours into the accident. Figure 48-1 presents the distribution of Level 2 accident sequence results for the rerate sensitivity analysis.

Table 48-1-1—Plant Damage States

Reactor Pressure at Vessel Failure	Containment Failure Mode	Timing of Release
R—Recovered in vessel L—Vessel pressure low at lower head penetration H—Vessel pressure high at lower head penetration	XX—Containment intact VS—Containment vented through pool VB—Containment vented bypassing pool OD—Overpressure failure due to steam from decay heat or noncondensible gas generation OT—Overtemperature failure OA—Overpressure failure due to steam generation from ATWS OH—Overpressure failure due to hydrogen combustion EC—Containment failure due to early severe accident challenges LM—Liner melt-through CI—Containment isolation failure BY—Containment bypass	X—Containment intact L—Late release ~24hrs I—Intermediate release >6hrs E—Early release <6hrs

Table 48-1-2—Release Modes

	Debris Cooling Systems	Radionuclide locations prior to vessel failure	Small Failure: Before or as a result of Vessel Failure	Small Failure: Delayed after Vessel Failure	Large Failure: Before or as a result of Vessel Failure	Large Failure: Delayed after Vessel Failure
Through Suppression Pool	CS[1]	WWA/DW	B1[3]		B2[3]	
		WWW				
	No CS + RPV Inj	WWA/DW				
		WWA				
	No CS + No RPV Inj	WWA/DW				
		WWW				
Bypass Suppression Pool	CS	WWA/DW	C1	D1[4]	C2	D2[4]
		WWW	C3		C4	
	No CS + RPV Inj	WWA/DW	C5	D3[4]	C6	D4[4]
		WWW	C7		C8	
	No CS + No RPV Inj	WWA/DW	C9	D5[4]	C10	D6[4]
		WWW	C11		C12	
Bypass Containment	CS	WWA/DW	E1[5] E2			
		WWW				
	No CS + RPV Inj	WWA/DW				
		WWW				
	No CS + No RPV Inj	WWA/DW				
		WWW				

Other Release Modes:

A1 - Recovered in vessel, containment leakage only
A2 - Recovered in vessel, vent through the suppression pool
A3 - Recovered in vessel, vent through the drywell
A4 - Core debris in containment, containment leakage only
A5 - Core debris in containment, vent through the suppression pool
A6 - Core debris in containment, vent through the drywell

[1] CS = Containment spray

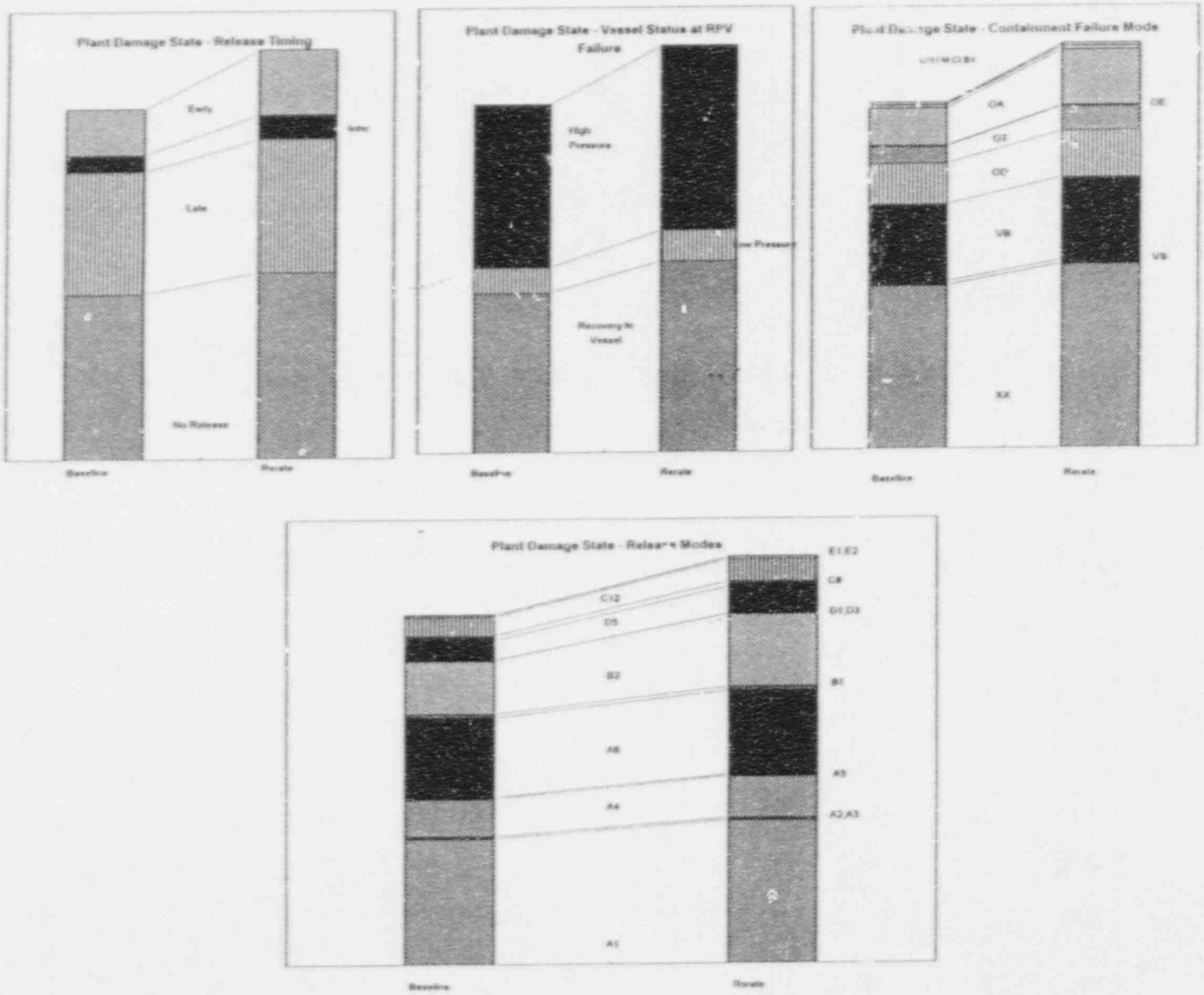
[2] DW = Drywell, WWW = wetwell below waterline, WWA = wetwell airspace

[3] Debris cooling systems and radionuclide location before vessel failure do not affect the release category definition due to the large suppression pool decontamination factor. Timing of release vs. vessel failure is not important to the release category definition as releases are principally limited to noble gases.

[4] Distinction between WWA/DW and WW is not significant to the Release Mode definition because of the long time for natural aerosol removal (gravitational settling and gradual flow of steam and aerosols to the suppression pool prior to containment failure are assumed to be effective in removing early aerosol releases from the vessel).

[5] E1 = Containment Isolation Failure, E2 = Containment bypass

Level 2 PRA
Figure 1



Part II. Risk Analysis Results for IPEEE

The external events review was conducted for three distinct categories: seismic, internal fires, and other events. This is similar to the manner in which the IPEEE was performed. The methodology used to perform the analysis for both internal fires and tornado missiles involved quantification. The results of the new quantification performed as a part of the rerate analysis are provided below.

Internal Fires

NSPNAD-92003, Rev. 0 (IPE) and NSPNAD-95001, Rev. 1 (IPEEE) discuss the classification of core damage sequences into functional categories based upon characteristics of the accident sequences with respect to reactor and containment conditions at the time core damage is assumed to occur. These functional categories are called "accident classes."

The potential types and frequencies of accident scenarios at a nuclear power plant cover a broad spectrum. In order to limit these sequences to a manageable number, sequences with similar functional characteristics are grouped together. Three such functional classes were defined for the Monticello fire IPEEE:

Class 1A - Transient-initiated events in which all high pressure injection systems become unavailable and depressurization of the reactor to allow low pressure injection is not accomplished. Core damage is assumed to occur with the reactor at high pressure for these sequences.

Class 1D - Transient-initiated events in which all high and low pressure injection systems become unavailable. Depressurization of the reactor is successful for these sequences. Core damage is assumed to occur at a low reactor pressure.

Class 2 - Core damage events which occur as a result of the inability to remove decay heat from the containment. All means of heat removal are assumed not to function for this accident class, including the main condenser, containment venting, and RHR in shutdown cooling, suppression pool cooling, and wetwell and drywell spray modes. This accident sequence takes days to develop, saturation of the pool taking more than eight hours, pressurization to containment design on the order of a day, and closure of SRVs prohibiting low pressure injection at least thirty hours into the event. High pressure systems must also fail to result in core damage for this accident class.

These accident classes are typical of other PRAs and are a subset of those used in the Monticello internal events PRA. Other accident classes that were not considered to be applicable to the fire PRA include:

Class 1B - Station blackout. No single fire area is likely to result in a loss of all AC power at Monticello.

Class 3 - LOCAs. No fire initiator was identified that could credibly lead to a loss of coolant accident.

Class 4 - ATWS. No fire initiator was identified that could credibly lead to a failure of the reactor protection system. The simultaneous, independent failure of the reactor protection system or of control rod insertion during a fire is probabilistically insignificant.

The human error rates for the important human errors in the fire PRA are provided in Table 48-2-1. A comparison of the quantification results for the baseline case and the rerate case are provided in table 48-2-2. The rationale for the increase in CDF associated with Class 1A is similar to that for the internal events PRA. But, unlike class 2 of the internal events evaluation, a relatively large portion of the increase in CDF from the internal fires is a result of accident sequences in which containment heat removal is lost. Fires contributed more to accident class 2 because there are a few locations in the plant that contain support equipment for multiple trains of decay heat removal systems (such as RHR and the hard pipe vent). The increase in CDF due to the rerate results from a reduction in time to repair failed decay heat removal equipment (from 27 hours to 24 hours).

Tornado Missiles

Tornado generated missiles have a potential in striking and penetrating certain exposed areas of the plant and thus damaging safety-related equipment that are required for accident mitigation. Although the power rerate does not alter the tornado missile strike probabilities, it does affect the time for operators to mitigate the various accident scenarios that may occur. To assess the effect of the shorter response time available to the operators, the affected human error events were revised accordingly and the accident sequences were re-quantified. The resulting CDF of the base case and the rerate case for the areas that are vulnerable to a missile strike is presented in Table 48-2-3.

Table 48-2-1 Internal Fire HEPs

Basic Events	Description	Base Case Probability	Rerate Probability
XRPVBLDWNY	Vessel Depressurization	1.1E-3	1.4E-3
ASDS	Failure to man ASDS panel	3.4E-3	3.4E-3
RLOTORCLGY	Failure to align torus cooling	2.4E-5	2.4E-5
SUP-MC	Suppression in the Main Control Room	1.0E-2	1.0E-2
SUP-CS	Suppression in Cable Spreading Area	5.0E-2	5.0E-2
DCD40XXXXY	Failure to align alternate battery charger D40 to RCIC	1.0E-2	1.0E-2
PUMP-48HR	Failure to repair failed pump in the reactor building (Class2)	2.4E-1	2.8E-1
ELECT-6HR	Failure to repair failed I&C component (Class1A)	3.7E-1	3.9E-1

Table 48-2-2 Level 1 Core Damage Frequencies by Accident Classes (Base and Rerate Cases)

Internal Fire				
Accident Class	Core Damage Frequency- baseline (per year)	Core Damage Frequency- 112% Power Level (per year)	ΔCDF rel to overall baseline power level CDF	ΔCDF rel to baseline Accident Class
1A	2.91E-06	3.19E-06	3.36%	9.62%
1D	3.25E-06	3.25E-06	0.00%	0.00%
2	2.18E-06	2.36E-06	2.16%	8.26%
Overall CDF	8.34E-06	8.80E-06	5.52%	5.52%

Table 43-2-3 Core Damage Frequency Due to Tornado Generated Missiles

Tornado Generated Missiles Vulnerabilities			
Plant Areas that are Affected by a Missile Strike (Associated Fire Area)	Core Damage Frequency-baseline (per year)	Core Damage Frequency- 112% Power Level (per year)	**Delta CDF** relevant to overall baseline power level CDF
Walls/roof TB 951 Turbine deck (FIRE-XII)	1.63E-09	1.65E-09	0.17%
East face RB 985, louvers (FIRE-3A)	6.80E-10	6.82E-10	0.02%
South face RB Ground, double doors	7.60E-09	7.60E-09	0.00%
South face RB Ground, double doors (FIRE-X)	5.79E-11	6.03E-11	0.02%
West face RB Ground, access door	1.20E-09	1.20E-09	0.00%
West face RB 946, louvers	1.85E-09	1.85E-09	0.00%
West face RB 955, louvers	1.85E-09	1.85E-09	0.00%
West face TB 945, electrical penetration (FIRE-14A)	2.07E-10	2.07E-10	0.00%
West face TB 935, electrical penetration (FIRE-X)	1.26E-11	1.31E-11	0.00%
DG roof, diesel intake/exhaust lines	Screened	Screened	0.00%
Overall CDF	1.51E-08	1.51E-08	0.20%

49. *On page 10-14, the second paragraph states "Human Reliability Analysis (HRA) .... This portion of the PRA involves some of the largest uncertainty in failure probability estimates...." In view of such uncertainty in the HRA and since the CDF increase of 2.4E-6/Yr (or 17.5 percent increase from the Monticello baseline CDF) is not considered insignificant, the staff needs to review the uncertainty analyses to understand how uncertainties were addressed, both quantitatively and qualitatively, in the decision making process.*

NSP Response

The largest effect that rerate has on the PRA is due to the time available for operators to respond to conditions occurring in a variety of accident sequences. Several types of uncertainty were considered in reviewing the impact of rerate on the operator actions included in the PRA. The following addresses the reviews performed to examine these uncertainties. These reviews identified no new operator actions that are important to the rerate that were not already considered in the original evaluation. The model uncertainty discussion below concludes that the contribution of operator actions to risks associated with the rerate may be, in fact, less than that indicated by the PRA.

Numerical Uncertainty

To determine the effects of uncertainty associated with operator actions, sensitivity studies were performed in which the failure probability for each operator action was varied over the full range of probabilities from 0 to 1. The results of this analysis were used to generate importance measures for each operator action. As noted in the probabilistic risk assessment section of the power rerate license amendment request, NEDC-32546P, those operator actions to which the results were most sensitive were subject to further review as to the effects of reducing the time available to perform these actions due to the rerate. Any operator action which, by itself, could contribute to accident sequences totaling more than 1E-6/year were candidates for further review. The operator actions identified as important as a part of this study are presented in Table 1 of question 47.

Varying the failure probabilities of each operator action over the full range bounds the effect of any numerical uncertainties associated with their failure probabilities. However, it was recognized that if accident sequence cut sets existed in which more than one operator action occurred, there could be a multiplicative effect on the overall core damage frequency that would not be recognized by varying the failure probabilities one operator action at a time. For this reason, additional sensitivity studies were performed to identify those cut sets containing multiple post initiator operator actions. In addition to examining multiple operator actions in the retained cutsets, the sensitivity studies included a search for cutsets that would have had multiple operator actions if they had not been truncated from the results. The results of this sensitivity study are contained in Table 49-1. No new operator actions were identified as a result of this evaluation that would be affected by the rerate that were not already noted in Table 1 of question 47.

Model Uncertainty

Operator actions to initiate emergency depressurization during transients and initiate SLC in response to an ATWS make up the bulk of the change in risk due to the rerate. In reviewing the outcome of the PRA evaluation, it should be noted that there are some modeling assumptions that have an effect on these actions.

For transient events requiring emergency depressurization, few sequences credit the ability of the CRD pumps to makeup to the reactor, thereby extending the time assumed to be available to depressurize the reactor. Furthermore, the SRVs in their depressurization mode are essentially modeled as a manually initiated system due to an assumption that ADS is always inhibited on low reactor water level in accordance with the EOPs. In fact, ADS is automatic. That the operators recognize the need to inhibit ADS reflects their awareness of low reactor water level conditions and increases the likelihood that emergency depressurization will be initiated successfully on reactor inventory reaching the top of active fuel. Each of these two modeling assumptions artificially increase the contribution of failing to initiate emergency depressurization on the overall CDF.

With respect to SLC initiation, examination shows that the accident sequences which are affected most by the rerate are those in which feedwater continues to run, maintaining reactor level and hence reactor power relatively high. In quantifying ATWS sequences, an assumption has been made that the reactor initially is operating at 100% power. No attempt has been made to use historical data to distribute initiating events between those that occur at partial vs. full power. Furthermore, complete failure of control blade insertion is assumed. That is, an attempt to quantify the potential for partial rod insertion, reducing initial power, has not been made. Both of these assumptions minimize the time available for the operator to respond to an ATWS. The actual contribution to core damage resulting from failure to initiate SLC may be less than quantified in the PRA, as a result.

Consideration of Unmodeled Accident Scenarios

The quantitative analysis performed with the PRA include internal events, internal flooding and internal fires. Qualitative evaluation was performed for initiators not explicitly modeled in the PRA, such as earthquakes and other external events. The rerate is expected to have little or no effect on shutdown risk.

In the PRA section of the rerate license amendment request, it was concluded that the potential for seismic and other external event initiators and response of plant equipment to these events was unaffecied by the rerate. Further, as the types of accident sequences expected for these initiators are similar to that modeled in the internal events PRA, the timing associated with these accident sequences would be similar to that found in the internal events PRA. As a result, uncertainties in important operator actions for seismic and other external events are similar to that discussed above. That is, important operator actions have been identified as a part of the internal events PRA and are found to have only limited impact on the results of the PRA.

Table 49-1 Multiple Operator Actions

Transient Restore FW after a high level trip Emergency depressurization	CDF for this combination of actions = 1.2E-7/yr	Both actions already identified as potentially important and included in sensitivity study to determine effects of reduced timing due to rerate
LOCA Restore FW after a high level trip Emergency depressurization	CDF for this combination of actions = 4E-8/yr	Both actions already identified as potentially important and included in sensitivity study to determine effects of reduced timing due to rerate
Align Service Water to the Main Cond Emergency depressurization	CDF for this combination of actions = 8E-8/yr	Alignment of SW to the main condenser has been given only limited credit in the baseline CDF calculation due to anticipated difficulty in performing this action (failure probability = .75). Little impact on this action or the CDF is expected due to rerate.
Place standby bat charger in service Emergency depressurization	CDF associated with this combination of actions < 1E-10/yr	Alignment of backup battery chargers is initiated in response to dc trouble alarms. It is important to accomplish over the time frame in which battery depletion would occur and is therefore independent of rerate affects.
Align Service Water to the Main Cond Makeup to the CSTs	CDF associated with this combination of actions < 1E-10/yr	CSTs are sufficiently large that makeup would be an issue only during medium LOCA sequences, a small part of the CDF. Further, alignment of SW to the main condenser has been given only limited credit in the baseline CDF calculation due to anticipated difficulty in performing this action (failure probability = .75). Little impact on this action or the CDF is expected due to rerate.
Initiate torus cooling Repair failed heat removal systems	CDF associated with this combination of actions < 1E-10/yr	Rerate affects only the diagnosis time for alignment of torus cooling which is significant (on the order of a day) and therefore plays little or no role in determining the potential for successfully performing this action
Initiate torus cooling Initiate containment venting	CDF associated with this combination of actions < 1E-10/yr	Rerate affects only the diagnosis time for alignment of torus cooling which is significant (on the order of a day) and therefore plays little or no role in determining the potential for successfully performing this action.

Containment Systems

50. *It is indicated in USAR Table 5.2-4 that maximum drywell pressure is 42.0 psig rounded off to the nearest psi. In NEDC-32546P ("Power Rerate Safety Analysis Report for Monticello Nuclear Generating Plant," proprietary information - not publicly available) Table 4-1 it is stated that peak drywell pressure is 41.0 psig at 102 percent of 1670 MWt using Mark I long-term program (LTP) method and 39.0 psig using Mark I LTP method with break flow from more detailed RPV Model. Please discuss the reasons for the difference between the USAR and MARK I numbers. Also discuss the reasons why the pressure goes up by only 1 psig to 40 psig when power is raised from 1670 MWt to 1880 MWt using the same method.*

Please confirm that if pressure is rounded off, it is rounded to the next higher number. Please indicate key input parameters besides power related that are different from the USAR and the effects on peak pressure.

NSP Response

The difference between the peak drywell pressure shown in USAR Table 5.2-4 (42.0 psig) and NEDC-32546P Table 4-1 (41.0 psig) is due to the values assumed for the initial containment conditions. The USAR value was based on initial conditions that maximize the peak drywell pressure while the power rerate value was based on initial conditions consistent with the Mark I Long-Term Program (LTP) short-term loads evaluations. The peak drywell pressure entries in Table 4-1 of NEDC-32546P have been revised in the table below based on using a consistent set of input assumptions that maximize the calculated peak drywell pressure. These initial conditions, with the exception of initial containment pressure discussed below, are the same as those used in the Reference 1 USAR analysis. An additional benchmark case for the change in initial containment pressure has been included to more clearly show the progression from the current USAR value to the power rerate peak drywell pressure. The values in the table below are shown to three significant figures with the last figure rounded up from the calculated value.

The USAR peak drywell pressure of 42.2 psig was calculated using the Mark I LTP method and assumed an initial containment pressure of 1.0 psig. Increasing the initial containment pressure to 2.0 psig resulted in an increase in peak drywell pressure of 0.7 psi to 42.9 psig (again using the Mark I LTP method). Changing the break flow model to the more detailed RPV model reduces the peak drywell pressure more than 2 psi to 40.7 psig. The change in reactor operating conditions from a power level of 1670 MWt to 1880 MWt result in a small reduction in the peak drywell pressure to 39.6 psig (again using the break flow from the more detailed RPV model). The 1670 MWt and 1880 MWt entries had been inadvertently switched in the original Table 4-1. In all cases, there is significant margin to the 56 psig containment design pressure limit.

The break flow model in the original Mark I LTP method significantly overpredicts the break flow during the first couple of seconds. The critical break flux is determined by the initial pressure and enthalpy conditions in the vessel downcomer and is assumed constant until all the subcooled water in the recirculation piping and vessel downcomer has been depleted. The break flow is determined by the sum of the flows through the recirculation outlet (suction) nozzle and reverse flow through the jet pump nozzles and out the recirculation discharge piping. Choked flow is assumed to occur almost immediately at the outlet nozzle. The break flow from the recirculation discharge piping is initially assumed to be choked at the pipe end, with the flow area determined by the pipe area. Choked flow at the jet pump nozzles is assumed to occur only after the recirculation piping has been emptied. These assumptions lead to a very high break flow during the first few seconds of the event. In addition, the break flow calculated in this manner is very sensitive to changes in the initial vessel pressure and downcomer enthalpy. The high initial break flow causes a high drywell pressurization rate. The peak drywell pressure occurs quickly (at about 1 second), and because the peak occurs quickly, the peak value is dependent on the vent clearing characteristics. The break flow assumptions, therefore, make the calculated peak drywell pressure sensitive to the initial conditions.

The more detailed RPV model calculates a more realistic break flow during the early part of the event. The RPV model has separate nodes for the downcomer and recirculation pipe. The critical flux is calculated separately for flow between the nodes and flow out the break. The critical flux is calculated based on the pressure and enthalpy conditions during the transient. The critical flux decreases as the vessel pressure falls and the subcooling lessens, which reduces the break flow. In addition, choked flow at the jet pump nozzles occurs much more quickly, further reducing the break flow. The initial break flow is about the same as that calculated with the Mark I LTP method, but the break flow falls off more quickly, resulting in a slower drywell pressurization rate and later peak drywell pressure. The peak drywell pressure occurs at about seven seconds, which is well after the vents have cleared. Therefore, the calculated peak value is not sensitive to the vent clearing characteristics. The peak drywell pressure occurs about the time that the vessel downcomer has emptied, which means the peak drywell pressure is primarily dependent on the mass and energy stored in the vessel downcomer water and the initial reactor pressure which determines the overall rate at which the downcomer empties. The more realistic break flow calculation, therefore, makes the calculated peak drywell pressure less sensitive to changes in the initial conditions than the Mark I LTP method.

The peak drywell pressure is primarily dependent on the mass and energy stored in the vessel downcomer water and the initial reactor pressure which determines the overall rate at which the downcomer empties. The peak drywell pressure occurs too quickly to be affected by heat transfer from the core or changes in decay power resulting from changes in the initial reactor power. The reactor power has a small effect on the energy stored in the downcomer because the reactor power determines the amount of feedwater flow to the vessel. The downcomer enthalpy is determined by the mixture of the saturated water recirculated in the vessel and the colder feedwater flow. At a constant core flow, an increase in reactor power results in an increase in the steam flow leaving the vessel, slightly warmer feedwater flow returning to the vessel (the increased steam flow provides more feedwater heating) and a decrease in the saturated recirculated water (essentially total core flow minus steam flow). The increased feedwater flow and temperature is offset by the reduced recirculation flow, resulting in a slight decrease in downcomer enthalpy.

For MNGP, there is no change in the reactor pressure assumed for power rerate. Similarly, there is no change in the initial reactor water level (mass in the downcomer). Therefore, power rerate only changes the energy stored in the downcomer. As shown in Table 1-2 of NEDC-32546P, the core inlet enthalpy (essentially the same as the downcomer enthalpy) is reduced by almost 1 Btu/lb for a power increase to 1775 MWt; the reduction in downcomer enthalpy is about double for a power increase to 1880 MWt. Power rerate, therefore, results in a slight decrease in the stored energy in the vessel downcomer. This reduction in stored energy is reflected in the small decrease in the peak drywell pressure at power rerate shown in the table below.

The only key input parameter in the power rerate analysis that is different from the USAR (besides changes related to the increase in reactor power) is the initial pressure in the drywell and wetwell. The USAR analysis assumed an initial pressure of 1.0 psig, while the power rerate analysis assumed that the initial pressure was at the drywell pressure scram setpoint of 2.0 psig in order to provide an analytical basis for the future implementation of Improved Technical Specifications. The increase in initial pressure causes the peak drywell pressure to increase by an amount somewhat less than the initial pressure increase. As shown in the revised entries for Table 4-1 below, the 1.0 psi increase in initial containment pressure resulted in an increase in the peak drywell pressure of 0.7 psi.

Table 4-1 LOCA CONTAINMENT PERFORMANCE RESULTS

Parameter	102% of 1670 MWt	102% of 1880 MWt	Limit
Peak Drywell Pressure (psig)	42.2(1) at 1.2 seconds 42.9(2) at 1.2 seconds 40.6(3) at 7.0 seconds	39.5(3) at 6.9 seconds	56(4)

Notes
(1) Mark I LTP method, 1 psig initial containment pressure (from Reference 1)
(2) Mark I LTP method, 2 psig initial containment pressure
(3) Mark I LTP method with detailed RPV model, 2 psig initial containment pressure
(4) Containment design pressure

Reference
(1) NEDO-32418, "MNGP Containment Pressure and Temperature Response for USAR Update, Dec. 1994

51. *It is indicated in 4.1.1.1 for emergency core cooling system (ECCS) net positive suction head (NPSH) that the decrease in NPSH due to the increase in the long-term bulk suppression pool temperature at uprated power will be offset by the suppression pool temperature increase. Please provide the specific numbers.*

NSP Response

Revised calculations for the containment pressure and suppression pool temperature have been provided to the NRC in Exhibit E (GE-NE-T2300731-2) of NSP's License Amendment Request dated June 19, 1997 which was approved by Staff SER dated July 25, 1997. GE-NE-T2300731-2 provides the detailed input parameter values, assumptions, and results for a variety of conditions. The Staff's SER and NSP's associated letters provide justification for adequate NPSH at 1880 MWt.

The NRC has determined that an uncertainty adder of 2σ (95% confidence interval) is necessary for the use of the ANS 5.1-1979 decay heat model. In the ANS 5.1-1979 standard, uncertainty is expressed as a two sided 1σ. Since the upper bound of the normal distribution is the parameter of interest for power rerate, it is reasonable to construct the confidence interval from the one-sided upper tail of the normal distribution. For this distribution, an uncertainty of 1.645σ corresponds to 95% percentile. That is, a valid statistical inference with 95% confidence that the actual decay heat will be less than the calculated value if the sampling difference is 1.645σ. The 1880 MWt decay heat profile used for power rerate analyses bounds the decay heat profile of 1775 MWt with an 1.645σ adder. Given the above, it is reasonable to conclude that the 1880 MWt decay heat profile bounds the actual 1775 MWt decay with 95% confidence.

52. *Please provide the confirmatory calculations validating the results from the analyses using the SHEX computer code.*

NSP Response

The confirmatory calculations validating the results from the analyses using the SHEX computer code have been provided to the NRC in Appendix A of Exhibit D (GE-NE-T2300731-2) of NSP's license amendment request dated June 19, 1997 with supplements dated July 16 and July 21, 1997. These confirmatory calculations and analyses validated the use of the SHEX computer code for performing containment calculations that maximize the suppression pool temperature and containment pressures. The results of the confirmatory calculations are presented in Table A-1 below. A comparison of the peak suppression pool temperatures obtained with the SHEX code to the values obtained with the HXSIZ code (used for MNGP's previous licensing basis containment calculations) show that there is little difference (about 1°F) in the peak suppression pool temperature predicted by both codes with the use of either May Witt or ANS 5.1 decay heat. A comparison of the peak long-term secondary containment pressure (near time of peak suppression pool temperature) shows close comparison (<1 psi) between the results obtained with HXSIZ and SHEX.

A second benchmark calculation was provided in response to Question 5 in a letter from NSP to the Staff dated July 16, 1997. This benchmark calculation validated the results from the analyses using the SHEX computer code for containment calculations that use containment sprays or analysis assumptions (such as break flow thermal mixing efficiency) to minimize the containment pressure. The benchmark calculation for the wetwell pressure and the SHEX results are in close agreement (within one percent).

TABLE A-1 - SHEX CONFIRMATORY CALCULATION RESULTS
(from Appendix A of Exhibit D)

CASE	A-1	CASE 1 REF. A-1	A-2	CASE A.2 REF. A-1
Code	SHEX	M3CPT/ HXSIZ	SHEX	M3CPT/ HXSIZ
Rated Power* (MWt)	1670	1670	1670	1670
Decay Heat	ANS 5.1	ANS 5.1	May Witt	May Witt
RHR Heat Exchanger K (BTU/sec-°F) total	143.1	143.1	143.1	143.1
Initial Drywell & Supp. Chamb. Airspace Pressure (psia)	15.7	15.7	15.7	15.7
Pool Temp at 600s (°F)	142.3	145.0	144.6	146.0
Peak Suppression Pool Temperature (°F)	184.8	184.0	196.7	195.5
Secondary Suppression Chamber Airspace Pressure Peak (psia)	31.4	31.3	36.8	36.3

* Analyses performed at 102% of initial core thermal power.

REFERENCE

A-1 NEDO-32418, "Monticello Design Basis Accident Containment Pressure and Temperature Response for USAR Update," December 1994.

Reactor Systems-.

53. *In Section 3.2 of Exhibit E, did the overpressure analysis assume 102 percent of rerated power, 105 percent rerated steam flow, and an SRV opening tolerance of 3 percent?*

NSP Response

The overpressure analysis in Section 3.2 assumed an initial reactor power of 102% of 1775 MWt, 1040 psia initial steam dome pressure, 105% of rated core flow and an SRV opening pressure of 1142.3 psig, which includes an opening tolerance of 3 percent.

54. *In Section 3.5 of Exhibit E, the licensee should commit to performing the vibration monitoring of the reactor recirculation system (RRS) as stated in the GE generic report in Section 5.5.1.3 and the review of the plant operating data as specified in Section 5.6.2 to confirm that the RRS will accommodate the uprated flow conditions.*

NSP Response

Monticello will not operate the Reactor Recirculation System at any increased flow conditions due to uprate. The maximum system flow is constrained by other limitations. Presently the recirc system flow rate is limited by the following parameters.

Recirc pump motor current limit of 390 A and winding temperature limit of 248°F
MG Set drive motor current limit of 590 A and winding temperature limit of 230°F.
Recirc pump dp limit of 143 psid.

ICF operation has been approved for Monticello. During normal plant operation with operation near the end of cycle, recirc pump speed is increased in order to increase the reactor power output. In doing so, the recirc pump dp limit is usually reached first with the recirc pump motor current limit being approached as well. As a result, the recirc system has been operated in the past at the maximum achievable flow rate as determined by the above mentioned parameters with no associated problems with the Recirc System or the reactor vessel internals. These limits will remain in force at rerate conditions and the rerate does not involve an increase in pump speed. Therefore, recirc system flow will not increase above present conditions.