This letter forwards proprietary information in accordance with 10 CFR 2.390. The balance of this letter may be considered non-proprietary upon removal of Attachment 5.

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Constellation Energy · eDF

NINE MILE POINT
NUCLEAR STATION

February 19, 2010

U. S. Nuclear Regulatory Commission
Washington, DC 20555-0001

ATTENTION: Document Control Desk

SUBJECT: Nine Mile Point Nuclear Station
Unit No. 2; Docket No. 50-410

Response to Request for Additional Information Regarding Nine Mile Point Nuclear Station, Unit No. 2 – Re: The License Amendment Request for Extended Power Uprate Operation (TAC No. ME1476)

REFERENCES:

(a) Letter from K. J. Polson (NMPNS) to Document Control Desk (NRC), dated May 27, 2009, License Amendment Request (LAR) Pursuant to 10 CFR 50.90: Extended Power Uprate

(b) Letter from R. V. Guzman (NRC) to S. L. Belcher (NMPNS), dated December 23, 2009, Request for Additional Information Regarding Nine Mile Point Nuclear Station, Unit No. 2 – Re: The License Amendment Request for Extended Power Uprate Operation (TAC No. ME1476)

(c) Email from R. Guzman (NRC) to T. H. Darling (NMPNS), dated January 12, 2010, Re: NMP2 EPU Response to Component Performance and Testing RAI

(d) Email from R. Guzman (NRC) to T. H. Darling (NMPNS), dated January 27, 2010, RE: Fire Protection Group Regarding the 12/23 RAI Response in RAI D1 and D3

This letter forwards proprietary information in accordance with 10 CFR 2.390. The balance of this letter may be considered non-proprietary upon removal of Attachment 5.

A001
NRR

(e) Email from R. Guzman (NRC) to T. H. Darling (NMPNS), dated February 01, 2010, Re: Follow-up re: Piping & NDE Call

(f) Phone conversation between R. Guzman (NRC) and J. J. Dosa (NMPNS) on February 11, 2010, to supplement the response submitted on December 23, 2009 for RAI B2

Nine Mile Point Nuclear Station, LLC (NMPNS) hereby transmits revised and supplemental information in support of a previously submitted request for amendment to Nine Mile Point Unit 2 (NMP2) Renewed Operating License (OL) NPF-69. The request, dated May 27, 2009 (Reference a), proposed an amendment to increase the power level authorized by OL Section 2.C.(1), Maximum Power Level, from 3467 megawatts-thermal (MWt) to 3988 MWt. By letter dated December 23, 2009 (Reference b), the NRC staff determined that additional information was needed to support its review. Additionally, in response to References (c) through (f), NMPNS is providing supplemental information related to previously submitted responses to requests for additional information (RAIs). The information in Attachments 1 and 5 is provided to address the above-referenced RAIs and provide supplemental information. Attachments 2 and 3 provide revised pages to General Electric-Hitachi Nuclear Energies Americas LLC (GEH) reports provided with Reference (a).

Attachment 5 is considered to contain proprietary information exempt from disclosure pursuant to 10 CFR 2.390. Therefore, on behalf of GEH, NMPNS hereby makes application to withhold this attachment from public disclosure in accordance with 10 CFR 2.390(b)(1). An affidavit from GEH detailing the reason for the request to withhold the proprietary information is provided in Attachment 4. Attachment 1 provides a non-proprietary version of the information provided in Attachments 5.

Should you have any questions regarding the information in this submittal, please contact T. F. Syrell, Licensing Director, at (315) 349-5219.

Very truly yours,

S. [signature]

STATE OF NEW YORK :
: **TO WIT:**
COUNTY OF OSWEGO :

I, Sam Belcher, being duly sworn, state that I am the Vice President-Nine Mile Point, and that I am duly authorized to execute and file this response on behalf of Nine Mile Point Nuclear Station, LLC. To the best of my knowledge and belief, the statements contained in this document are true and correct. To the extent that these statements are not based on my personal knowledge, they are based upon information provided by other Nine Mile Point employees and/or consultants. Such information has been reviewed in accordance with company practice and I believe it to be reliable.

Subscribed and sworn before me, a Notary Public in and for the State of New York and County of Oswego, this 19 day of February, 2010.

WITNESS my Hand and Notarial Seal:

Lisa M. Doran
Notary Public

My Commission Expires:

9/12/2013
Date

Lisa M. Doran
Notary Public in the State of New York
Oswego County Reg. No. 01DO6029220
My Commission Expires 9/12/2013

SB/JJD

Attachments:

1. Response to Request for Additional Information Regarding License Amendment Request for Extended Power Uprate Operation (Non-Proprietary)
2. Replacement Pages for NEDO-33351, Revision 0, Safety Analysis Report for Nine Mile Point Nuclear Station Unit 2 Constant Pressure Power Uprate (LAR Attachment 3)
3. Replacement Pages for NEDC-33351P, Revision 0, Safety Analysis Report for Nine Mile Point Nuclear Station Unit 2 Constant Pressure Power Uprate (LAR Attachment 11)
4. Affidavit Justifying Withholding Proprietary Information in GE-Hitachi Nuclear Energy Americas LLC Document "NMP2 EPU Round 2 RAI Responses"
5. Response to Request for Additional Information Regarding License Amendment Request for Extended Power Uprate Operation (Proprietary)

cc: NRC Regional Administrator, Region I
NRC Resident Inspector
NRC Project Manager
A. L. Peterson, NYSERDA (w/o Attachment 5)

ATTACHMENT 1

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING LICENSE AMENDMENT REQUEST FOR EXTENDED POWER UPRATE OPERATION (NON-PROPRIETARY)

Certain information, considered proprietary by GEH has been deleted from this Attachment. The deletions are identified by double square brackets.

ATTACHMENT 1

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING LICENSE AMENDMENT REQUEST FOR EXTENDED POWER UPRATE OPERATION (NON-PROPRIETARY)

By letter dated May 27, 2009, as supplemented on August 28, 2009 and December 23, 2009, Nine Mile Point Nuclear Station, LLC (NMPNS) submitted for Nuclear Regulatory Commission (NRC) review and approval, a proposed license amendment requesting an increase in the maximum steady-state power level from 3467 megawatts thermal (MWt) to 3988 MWt for Nine Mile Point Unit 2 (NMP2). This attachment provides supplemental information in response to the request for additional information (RAI) provided by NRC letter dated December 23, 2009. The NRC request is repeated (in italics), followed by the NMPNS response.

Balance of Plant

RAI A1

In the turbine generator technical evaluation section, NMPNS discusses that the overspeed calculation for the turbine generator compares both the entrapped steam energy contained within the turbine and its piping and the sensitivity of the rotor train. The entrapped energy is expected by NMPNS to increase in EPU conditions. NMPNS also indicates that a hardware modification design and implementation process establishes the overspeed trip settings for the turbine generator. However, NMPNS neither explains how the expected increase in entrapped energy will affect the ability to maintain turbine speed within an acceptable range nor discusses how the specific hardware modification design and implementation process will affect the overspeed trip settings under EPU conditions.

Explain how the increase in entrapped energy in the turbine will affect the ability to maintain turbine speed within an acceptable range. In addition, describe how the changes to both the hardware design and implementation process will affect the turbine generator overspeed trip settings during EPU conditions.

NMPNS Response RAI A1

The proposed Extended Power Uprate (EPU) modifications to the High Pressure (HP) turbine rotor will increase the rotor inertia, which slows the acceleration rate of the turbine should a load rejection event occur. However, the entrapped steam energy contained within the turbine and its piping after the valves close also increases for EPU, which increases the acceleration rate of the turbine should a load rejection event occur. The overspeed calculation compares the entrapped steam energy contained within the turbine and the associated piping, after the stop valves trip, and the sensitivity of the rotor train for the capability of overspeeding. The scenario considered is the emergency case where the Electro Hydraulic Controls (EHC) and the control and intercept valves fail to respond to the initial speed increase due to a load rejection event. For this scenario, the unit rapidly accelerates to the overspeed trip set point, thereby trip closing the main and intermediate stop valves. The operating condition that results in the highest overspeed, at EPU conditions, was analyzed. This approach accounts for the two basic contributors to peak overspeed due to a load rejection event: 1) the energy due to entrapped (or entrained) steam within the steam path and inlet piping downstream of the main and intermediate steam valves; and 2) what is termed valve lag overspeed which takes into account the energy contributed by new steam entering the machine during response time of the control and trip systems, and during the actual closing time of these valves. The overspeed trip setting for NMP2 is established, such that the resulting peak speed will not exceed the 120% emergency overspeed limit due to overshoot for any condition. This ensures that the turbine is protected in an overspeed event. With the modifications to the main turbine for EPU conditions, the overspeed calculation shows that the mechanical overspeed trip setting requires adjustment to maintain the turbine overspeed within the 120% limit. For EPU, the overspeed trip setting is reduced from the original value of 1966-1984 RPM (109.2-110.2%) to 1960-1978 RPM (108.9-109.9%). This trip setting will result in an emergency overspeed peak of less than or equal to 120.0%, which meets GE's emergency overspeed peak speed limit requirement. In addition, a backup electronic overspeed protection system is available. The backup electronic overspeed protection system will send a trip signal to the master trip solenoid valve on a detected overspeed condition from independent speed sensors. The backup electronic overspeed set point is reduced from 111% to 110.5% to maintain the design relationship between the mechanical and backup overspeed trip settings.

RAI A2

NMPNS discusses in the main condenser evacuation system (MCES) technical evaluation section that no changes were made to the following areas of the MCES: (1) the condenser air removal system; (2) the parameters of the physical size of the primary condenser and evacuation times; and (3) the holdup time to the pump discharge line. However, in the conclusion, NMPNS states that required changes to the MCES were assessed and evaluated for EPU conditions. This statement contradicts the assessments made in the technical evaluation.

Clarify what required changes were made to the MCES, and how they were assessed for EPU conditions to continue to satisfy General Design Criteria (GDC)-60 requirements.

NMPNS Response RAI A2

No hardware changes to the MCES are required for EPU. The statement, "NMPNS has reviewed the assessment of required changes to the MCES and concludes that these changes have been adequately evaluated" is in reference to the required operational parameter changes to the Steam Jet Air Ejector (SJAE) required capacity and motive steam requirement, not hardware changes, required to accommodate EPU.

As noted in the MCES Technical Evaluation, Section 2.5.2.2, "The physical size of the primary condenser and evacuation time are the main factors in establishing the capabilities of the vacuum pumps. These parameters do not change. Because flow rates do not change, there is no change to the holdup time in the pump discharge line routed to the reactor building vent stack. The capacity of the SJAEs is adequate because they were originally designed for operation at flows greater than those required at EPU conditions."

Since the existing MCES at NMP2 meets regulatory requirements and no changes are required for EPU operating conditions the MCES will continue to meet regulatory requirements. GDC-60 requires NMPNS to control the release of radioactive materials to the environment. As the MCES EPU operational requirements are bounded by the current system design, the NMP2 MCES ability to meet GDC-60 requirements is unchanged.

RAI A3

In the spent fuel pool cooling and cleanup system (SFPCCS) technical evaluation section, NMPNS discusses that during the normal refueling outages at NMP2, post-EPU implementation, existing administrative controls and procedural limitations will be used to maintain the increase of decay heat for cycle specific full-core offload within design limits. These administrative controls and procedural limitations for SFPCCS are neither described in the LAR nor are they found in Section 9.1.3 of Revision 20 to the NMP2 Updated Final Safety Analysis Report (UFSAR). It is not clear how the existing administrative controls and procedural limitations will be used to maintain the SFPCCS within design limits with the increased decay heat load due to EPU conditions.

Describe the administrative controls and procedural limitations needed for SFPCCS and how they will be used for EPU conditions to continue maintaining the design limits for the SFPCCS during cycle specific full-core offload, as required by GDC-44.

NMPNS Response RAI A3

The Spent Fuel Pool Cooling System (SFPC) is cooled by the Reactor Building Closed Loop Cooling Water System (RBCLC), which is cooled by the Station Service Water System (SWS). The SFPC can also be cooled by the SWS directly. Compliance with GDC-44 for the RBCLC and SWS is discussed in the NMP2 Updated Safety Analysis Report (USAR). Implementation of EPU does not require changes to the RBCLC or SWS, such that continued compliance with GDC-44 will be assured. Currently, the heat load to the Spent Fuel Pool (SFP) is controlled by delaying the initiation of core offload to reduce the decay heat in the fuel and by controlling the rate of core offload. The capability of the SFPC to reject the required heat load is controlled by scheduling refueling outages during specific times of the year to ensure that SWS temperatures from Lake Ontario, the Ultimate Heat Sink (UHS) are below calculated limits and by specifying minimum SFPC equipment functionally requirements. Procedures/calculations that provide these administrative controls are discussed below.

Attachment 11, Table 2.5-3 of the license amendment request (LAR) provides peak SFP temperature values for post-EPU full core offloads and core shuffles. The temperatures provided assume core offload delays of 48 or 80 hours. Operating and fuel handling procedures control the required delay time in commencing offload, as well as the allowed offload rate (number of bundles per hour). The analysis supporting these values is contained in an engineering calculation, which also includes consideration of maximum expected SWS temperatures. This calculation will be updated for the higher EPU core thermal power and the identified procedures will be revised, as necessary, to maintain control of SFP decay heat load to ensure SFP temperatures remain within design basis requirements as part of EPU implementation.

Probabilistic Risk Assessment (PRA)

RAI B1

Review Standard (RS)-001, Attachment 1 to Matrix 13, Section 3.1, requires the licensee to address the impacts of EPU on components and system reliability and response times. Attachment 11, Section 2.13.1.2.2 of the Safety Analysis Report (SAR) addresses the reliability impacts, but does not identify *impacts on response times. Please provide a discussion of the impacts of the proposed EPU on component and system response times.*

NMPNS Response RAI B1

Attachment 6 of the LAR identifies the following modifications that will be implemented to minimize the probability of a low level scram upon loss of a single feedwater pump:

- Initiation of a recirculation flow control valve runback immediately upon a feedwater pump trip.
- Increasing the recirculation flow control valve runback rate from the current 6-8% per second to 9% per second.

The impact of the response times associated with these changes has been evaluated as demonstrating margin to scram avoidance that was consistent with current margin. Although this analysis concluded that the probability of a scram is not increased, a partial loss of feedwater initiating (PLOF) event was added to the PRA and a sensitivity analysis showed that the additional risk is small. This PRA analysis is documented in NEDC-33351P Rev 0, "Safety Analysis Report for Nine Mile Point Unit 2 Constant Pressure Power Uprate." No other changes to component and system response times impacted the PRA analysis.

RAI B2

RS-001, Attachment 1 to Matrix 13, Section 3.1, requires the licensee to describe how it ensures that the PRA adequately models the as-built, as-operated plant, and that the analyses supporting the EPU adequately reflects how the plant will be operated and configured for EPU conditions. Section 2.13 of the SAR does not show how the PRA adequately models the as-built, as-operated plant nor does it show how the PRA will be maintained post-EPU. Please provide a discussion of the missing information.

NMPNS Response RAI B2

NMPNS design and administrative procedures ensure that the PRA adequately models the as-built, as-operated plant. The analyses supporting the EPU adequately reflect how the plant will be operated and configured for EPU conditions. The scope of these procedures includes PRA maintenance, design changes, procedure changes and plant activities:

PRA Maintenance

The PRA configuration control procedure provides standard controls and processes for maintaining the PRA models and their associated applications, consistent with the as-operated, as-built plants in the Constellation Nuclear fleet.

Design Changes

The procedure that governs the NMPNS design and configuration control process requires notifying the PRA group of the proposed design and to request a design input/impact assessment.

Procedure Changes

The administrative procedure that governs the preparation and review of technical procedures requires that preparers complete a PRA screening form to determine whether or not the proposed change has the potential to affect the NMP2 PRA model.

Plant Activities

The integrated risk management procedure requires PRA based risk assessment of scheduled and emergent plant activities.

RAI B3

RS-001, Attachment 1 to Matrix 13, Section 3.1 and 3.2, requires the licensee to specifically address vulnerabilities, weaknesses, or review findings identified in the Individual Plant Examination (IPE), Individual Plant External Events Examination (IPEEE), and/or independent/industry peer review findings, that could impact the PRA results and conclusions. It further requires the licensee to present the overall findings of the peer review (by element) and to discuss low-rated elements, and any findings and observations that could potentially impact the licensee's proposed EPU. Attachment 11, Table 2.13-1 and Table 2.13-2 of the SAR shows the peer review findings and dispositions to the IPE, IPEEE, and peer reviews, but does not address how these findings may affect the proposed EPU. Please provide a discussion of the missing information.

NMPNS Response RAI B3

Attachment 11, Table 2.13-1 and Table 2.13-2 of the SAR "Findings and Dispositions" to the IPE, IPEEE, and peer reviews, were reviewed for their impact to the proposed NMP2 EPU. All the findings were dispositioned and addressed in the updated PRA for the EPU risk analysis. Three of the findings were dispositioned by assuming conservative assumptions or as having no or negligible impact on the important event sequences and equipment relative to the proposed NMP2 EPU. These comments are related to the following items listed in Table 2.13-1 in the Power Uprate Safety Analysis Report (PUSAR): external flooding (IPEEE-TE Pages ix, xii, 31-34, 44), equipment failures due to smoke and combustibles (IPEEE-TE Pages x, xii, 2, 24, 28, 44) and seismic hazard truncation (IPEEE-TE Page 43).

RAI B4

As part of the IPE process and in response to staff's questions for clarification, NMP2 committed to six hardware and procedural enhancements. Address how these commitments were met, and if they have not been met, state how it affects the proposed EPU.

NMPNS Response RAI B4

The following summarizes how the six hardware and procedural enhancements identified as part of the IPE process were resolved and considered in the PRA model used to evaluate the proposed EPU changes. Items identified below are referenced in PUSAR Table 2.13-2.

1. **Develop procedures to prevent Reactor Core Isolation Cooling (RCIC) trip under loss of service water.**

   Procedures were developed to prevent RCIC trip under loss of service water. The PRA model used to evaluate EPU incorporated these procedure changes.

2. **Install valves in the Standby Gas Treatment System (SGTS) to increase the reliability of containment venting.**

   In lieu of a piping modification related to containment venting (SGTS), procedure and training changes were made. Human reliability analysis (HRA) and models used in the EPU evaluation are based on current procedures/training. A reevaluation of the original commitment for this change was communicated to the NRC by correspondence dated July 14, 1994.

3. **Develop procedures to enhance Auxiliary Bay room cooling during loss of service water.**

   Procedure changes were implemented, after the EPU LAR submittal, to have operations open Emergency Core Cooling System (ECCS) pump room doors to facilitate natural cooling upon a loss of Service Water. As such, there is additional margin that was not credited in the PRA model used to evaluate EPU.

4. **Enhance Station Blackout (SBO) procedures.**

   Procedures were enhanced to improve operator response to SBO. The PRA model used to evaluate EPU incorporated these procedure changes.

5. **Provide additional internal flood guidance.**

   Procedures were revised to use the Control Building sump alarm to mitigate a flooding event on elevation 261' to prevent a loss of Division I and II emergency power. The PRA model used to evaluate EPU incorporated these procedure changes.

6. **Improve test & maintenance procedures to reduce the likelihood of an Intersystem Loss of Coolant Accident (ISLOCA).**

   No procedure changes made to reduce the likelihood of ISLOCA. Instead, the ISLOCA model includes this probability and online risk model manages this risk by increasing risk when the applicable procedures are being implemented. The original commitment for this change was modified as communicated to the NRC by correspondence dated July 14, 1994.

RAI B5

EPU SAR Attachment 11, Section 2.13.1.2.1 states no significant change to electrical reliability was identified with the EPU. Provide an explanation that summarizes which analyses or methodology was used for this conclusion and whether there are any changes in a loss of offsite power (LOOP) initiating event frequency or transformer reliability/life expectancy due to EPU.

NMPNS Response RAI B5

The methodology used to assess the impact of EPU on electrical equipment reliability consisted of a comparative analysis that evaluated the pre- and post-EPU operating duty and equipment continuous ratings for electrical components. Reductions in operating margins were then determined. Results of this analysis are summarized for major electrical components in PUSAR Table 2.3-4. Although margins are reduced under anticipated EPU operating conditions, electrical equipment will be operated within its design ratings. Therefore, it was concluded that there would be no significant change in electrical reliability and LOOP initiating event frequencies are unaffected.

EPU will result in an increase in loading of the main generator step-up transformers and operating margin will be reduced from 9% under current power level to 3% under EPU conditions. Because the transformers will be maintained and operated within their ratings, there is no reduction in reliability or normal life expectancy. However, the transformer cooling system is being modified to increase the cooling system capacity to minimize the increase in normal operating temperature under EPU conditions.

RAI B6

EPU SAR Attachment 11, Section 2.13.1.2.1 proposes no significant impact on internal flooding initiator frequencies due to the EPU. Since higher flow rates can contribute to changes in initiating event for floods, please provide a more thorough justification for your conclusion on how EPU flow rates will not affect internal flooding initiator frequencies or provide a sensitivity analysis addressing this potential increase.

NMPNS Response RAI B6

As described in PUSAR Section 2.5.1.1, the flow rates and/or the system inventories of moderate energy piping systems do not increase for EPU. The piping systems that will experience higher flow rates for the EPU are Feedwater, Condensate, and Main Steam; these were screened from the PRA as low risk. In addition, the flow rates are not a consideration in establishing pipe break frequencies for internal floods. Pipe break frequencies are based on pipe lengths, size, and system type.

Furthermore, the increased flow rates at EPU conditions do not significantly affect the potential for Flow Accelerated Corrosion (FAC).

RAI B7

EPU SAR Attachment 11, Section 2.13.1.5 provides a sensitivity calculation for a stuck open relief valve, and states that there is a 10-percent increase in expected demands, post-EPU, due to the power increase. While the sensitivity calculation demonstrates minor changes in core damage frequency (CDF) and large early release frequency (LERF), the probability of a stuck-open relief valve given a transient initiator would increase due to an increase in the number of safety relief valve (SRV) cycles. Discuss how the common cause failure (CCF) probability has changed due to the EPU and what methodology was utilized to determine the new probability for stuck-open relief valves.

NMPNS Response RAI B7

Failure of two or more SRVs, including the contribution from common cause failure, is assumed to be bounded by large break Loss of Coolant Accident (LOCA) in the NMP2 PRA and as such, the probability of two or more SRVs opening was not calculated. The LOCA sensitivity analysis in EPU SAR Attachment 11, Section 2.13.1.5 is assumed to subsume the contribution of multiple SRVs failing open.

As described in EPU SAR Attachment 11, Section 2.13.1.5, the total probability of a stuck open SRV was increased by 10% based on estimated number of challenges. Since this is the probability of one SRV sticking open, common cause failure does not apply.

RAI B8

EPU SAR Attachment 11, Section 2.13.1.2.3 states that the pressure following a plant trip with an anticipated transient without scram (ATWS) post-EPU will increase, but the number of open SRVs is not expected to change. Discuss the basis for why SRV success criteria remains the same for ATWS transient events between pre-and post-EPU. Describe any calculations and the methodology used for this assessment.

NMPNS Response RAI B8

The SRV success criterion is that the American Society of Mechanical Engineers (ASME) Service Level C vessel overpressure limit is not exceeded with 16 SRVs (i.e., two SRVs assumed failed). The short-term transient response shows the total relief valve flow increase (at EPU conditions) is about 6% of Current Licensed Thermal Power (CLTP) rated steam flow. Given the small increase in the relief flow, only 16 SRVs are required for EPU, same as pre-EPU.

Since pre- and post-EPU require the same number of SRVs for ATWS mitigation, the success criteria in the PRA are unchanged and no PRA calculations were necessary.

RAI B9

Describe any new operator actions developed due to the EPU, and describe the methodology utilized to determine the error probability associated with the new actions.

NMPNS Response RAI B9

There are no new credited operator actions required as a result of the EPU. A description of methodologies utilized to determine the error probability associated with the new actions is not applicable.

RAI B10

EPU SAR Attachment 11, Section 2.13.1.2.4 proposes a screening criteria for operator actions based on Fussel-Vesely (FV) > 0.01 and Risk Achievement Worth (RAW) > 2. The staff finds an FV > 0.005 as a more appropriate criteria to identify important operator actions for EPU. Provide a change in human error probability (HEP) assessment pre- and post-EPU for all operator actions impacted by the EPU that are either under 30 minutes; have an FV > 0.005; or have an RAW > 2.

NMPNS Response RAI B10

The overall conclusion is that with considering FV between 0.01 and 0.005, as well as actions required within 30 minutes, has an insignificant impact on the analysis results. As described below:

1. All HEPs with RAW > 2 were addressed in the submittal.

2. The following HEPs, which were identified with a CDF FV between 0.01 and 0.005, are summarized below:

   - ZCH02 – as described in Table 2.13-5, this HEP is not credited.
   - ZN203 – as described in Table 2.13-5, this HEP was screened as having no impact from EPU.
   - ZKR03 – as described in Table 2.13-5, this HEP was screened as low importance. If included, it would be similar to MSSZODMSSOP1OO01 (ZOD01) in Table 2.13-7, which indicates pre- and post-HEP is the same. Even if 15% change is assumed per footnote 2, the change in CDF would be ~1E-8, which is insignificant.
   - ZOB01 – as described in Table 2.13-5, this HEP was screened as low importance. If included, it would be similar to MSSZODMSSOP1OO01 (ZOD01) in Table 2.13-7, which indicates pre- and post-HEP is the same. Even if 15% change is assumed per footnote 2, the change in CDF would be ~1E-8, which is insignificant.
   - ZNR01 – as described in Table 2.13-5, this HEP was screened as low importance. If included, it would be similar to MSSZODMSSOP1OO01 (ZOD01) in Table 2.13-7, which indicates pre- and post-HEP is the same. Even if 15% change is assumed per footnote 2, the change in CDF would be ~1E-8, which is insignificant.

3. The following HEP, which was identified with a LERF FV between 0.01 and 0.005, is summarized below:

   - ZOV01 – as described in Table 2.13-5, this HEP was screened as low importance. If included, there would be no change in the HEP because a conservative timing of 10 minutes was used which bounds both pre- and post-HEP. Even if 15% change is assumed, the change in LERF would be < 1E-9, which is insignificant.

4. The following HEPs, which were indentified with timing less than 30 minutes and not previously identified above or in Table 2.13-7 of the submittal, are summarized below:

    - ZAI01 – ATWS response (inhibit Automatic Depressurization System (ADS)) as described in PUSAR Table 1.13-5, under worst conditions is required within the first few minutes after an ATWS. The difference in timing is not judged significant since these events are considered more immediate demand based rather than time based. The time is very short regardless of power level and their importance is low.

    - ZAI02 – ATWS response (inhibit ADS) as described in PUSAR Table 1.13-5, under worst conditions is required within the first few minutes after an ATWS. The difference in timing is not judged significant since these events are considered more immediate demand based rather than time based. The time is very short regardless of power level and their importance is low.

    - ZODA – ATWS response (inhibit ADS) as described in PUSAR Table 1.13-5, under worst conditions is required within the first few minutes after an ATWS. The difference in timing is not judged significant since these events are considered more immediate demand based rather than time based. The time is very short regardless of power level and their importance is low.

    - ZOA01 – Station Blackout response (bypass RCIC isolation), timing is dependent on room heat-up, which is not affected by EPU. Even if a small change (e.g., 15%) is assumed, the change in CDF would be < 1E-9, which is insignificant.

    - ZCRD01 – early Control Rod Drive (CRD) response (align standby CRD train) is not credited in the model as described in PUSAR Table 2.13-5.

RAI B11

EPU SAR Attachment 11, Table 2.13-7 presents an operator action evaluation pre- and post-EPU. This table does not provide the basis or methodology for this analysis, nor parameters or models used. Submit an updated table including additional results from RAI Question B10 that includes the methodology utilized to determine the updated HEP results.

NMPNS Response RAI B11

Attachments 2 and 3 provide updated tables, NEDO-33351 Table 2.13-7 and NEDC-33351P Table 2.13-7 as requested.

The HRA for EPU was performed using the Electric Power Research Institute (EPRI) HRA Calculator software. Actions that did not require alteration for EPU conditions were left at their baseline values.

These Human Error Probabilities (HEPs), notated with the "(8)" in the post-EPU column of PUSAR Table 2.13-7 were developed prior to introduction of the HRA Calculator and were not reevaluated with the HRA Calculator software. However, the methodology used is consistent.

The preferred approach is to use the Caused Based Decision Tree Method (CBDTM) for cognitive errors and Technique for Human Error Rate Prediction (THERP) for execution. The failure rates for these methods are combined to yield the total action HEP. Since the CBDTM can produce a fairly small number for short-time window actions, the Human Cognitive Reliability (HCR)/ Operator Reliability Experiments (ORE) or Accident Sequence Evaluation Program (ASEP) methods are also evaluated for HEPs with a short time-window. For these short time-window HEPs, the HCR or ASEP value is added to the value derived from the CBDTM/THERP calculations.

RAI B12

EPU SAR Attachment 11, Table 2.13-2, Element IE, Sub-element 7 highlights exclusion of Break Outside Containment (BOC) as an initiator. Parts of the secondary systems could be considered wear areas in the flow accelerated corrosion (FAC) program. Provide a more thorough assessment of why BOC is not included as an initiator and the potential risk impacts due to EPU.

NMPNS Response RAI B12

Feedwater and main steam system high energy line breaks outside containment are currently modeled in the PRA and the CDF contribution from these modeled events is less than 1E-8/yr and LERF contribution is less than 1E-9/yr. Even if a 10% increase was conservatively assumed, this would result in a less than 1E-9/yr change in CDF, which is an insignificant risk impact.

Initially, the Break Outside Containment (BOC) initiators were screened from the PRA for the LAR submittal. The increase in flow rates due to EPU is not expected to increase failure rates in plant piping due to FAC. Therefore, the post EPU PRA updates do not require a change to the internal flooding initiating event frequencies or the high energy line break outside containment frequencies.

RAI B13

EPU SAR Attachment 11, Table 2.13-2, Element DA, Sub-element 15 states that the probability of a stuck open relief valve (SORV) conditional on its need to open for various transient initiators is not modeled. The staff does not understand how transients with an SORV are accounted for in the NMP2 PRA. The EPU increases the probability of SORV openings, therefore; provide a more thorough explanation explaining how SORV conditional probability is modeled in the NMP2 PRA and its EPU impact.

NMPNS Response RAI B13

The probability of a stuck open SRV due to transient initiating events was added to the inadvertent open relief valve (IORV) initiating event in the NMP2 PRA (the EPU impact is included in EPU SAR

Attachment 11, Section 2.13.1.5). The following summarizes how the total IORV initiating event was developed in the PRA:

A transient induced medium LOCA due to a stuck open SRV or the inadvertent opening of a SRV is identified as the initiating event IORV and is quantified as follows:

$$IORV = SRV_{io} + SRV_{ch} \times SRV_{ftc} = 1.6E\text{-}2 + 3 \times 1.3E\text{-}3 = 2E\text{-}2\text{/reactor year}$$

Where:

SRV_{io} is the frequency of a SRV inadvertently opening during operation. This frequency is based on generic experience (data variable VRZN1); no events have occurred at NMP2.

SRV_{ch} is the frequency of SRV challenges per reactor year which is a function of initiating event, its frequency, and the number of SRVs that open which is dependent on the initiating event. Three SRVs are assumed to open per year, which is conservative.

SRV_{ftc} is the probability that a SRV fails to reclose on demand. This is based on database variable VPZB1 (1.3E-3).

RAI B14

EPU SAR Attachment 11, Section 2.13.1.3.1 provides information on seismic events. Explain and provide a seismic risk impact of any new vulnerabilities due to EPU implementation, and whether modifications will affect structures or component anchoring mechanisms.

NMPNS Response RAI B14

There are no new seismic vulnerabilities due to EPU. EPU modifications will not affect structures or component anchoring mechanisms.

As documented in PUSAR Section 2.2.5, seismic margins have decreased, but they are still within code allowable and do not impact the seismic qualification of equipment; therefore, the reduced margins do not impact assumptions considered in the PRA.

The NMPNS design and configuration control process includes notifying the structural engineering and PRA groups of the proposed design and to request a design input/impact assessment for seismic and PRA impact.

RAI B15

EPU SAR Attachment 11, Section 2.13.1.4 discusses EPU impact on shutdown. The attachment states there is negligible impact on suppression pool cooling capacity, blow down loads, and reactor pressure *vessel (RPV) over pressure success criteria. Discuss the risk impact of SRV actuation success criteria during shutdown post-EPU. In addition:*

a. Explain how the EPU affects the scheduling of outage activities.

b. Provide additional information regarding the reliability and availability of equipment used for shutdown operations.

c. Explain how the EPU affects the availability of equipment or instrumentation used for contingency plans.

d. Explain how the EPU affects the ability of the operator to close containment.

e. Describe the plant's shutdown risk management philosophies, processes, and controls relied upon to ensure that the risk impact of the EPU for shutdown operations is not significant.

NMPNS Response RAI B15

Only one SRV is required once the plant is aligned for Shutdown Cooling operation, for both pre- and post-EPU. Therefore, no change in SRV success criteria is required.

a. Effective outage planning and control is the primary means of enhancing safety during shutdown conditions. Assessing and managing increase in risk and maintaining safety functions during a multitude of outage activities requires a clear understanding of NMP's Risk Management Philosophy. This philosophy includes involvement from all organizational levels in the planning and coordination of outage work, good communications, and the constant awareness of plant status by personnel involved in outage activities. Outage scheduling will continue to utilize Shutdown Risk assessments to determine appropriate timing and scheduling of outage activities to minimize risk for EPU. Outage activities during shutdown conditions present a number of unique situations and evolutions for both the permanent plant staff and for temporary personnel, such as additional craft and technicians. For example, operators will be relied upon to conduct many infrequently performed activities and will also be responsible for maintaining the plant in a safe condition under various plant configurations. Training on the risks during shutdown conditions can enhance operator awareness and provide knowledge of the appropriate response to potential adversities. The key outage shutdown safety features evaluated are decay heat removal, inventory control, electrical power availability, reactivity control, and containment closure. The following questions are assessed by procedure for scheduling outages and maintaining Safe Shutdown.

   1. Are daily activities scheduled concurrently that could result in a more restrictive Technical Specification (TS) Action Statement or cause the Unit to drop below its Minimum Essential Equipment List (MEEL)/Minimum Safe/Shutdown requirements?

   2. Could the activity affect the ability to restore containment closure, if required, integrity or containment cooling (including Secondary Containment)?

3. Are there any activities of significant complexity for which multiple disciplines or multiple procedures are required to complete the activity?

4. Are there any activities of significant complexity for which procedures do not exist to support execution?

5. Does the activity place a system in a configuration that could result in an inadvertent or unplanned actual change in reactivity or change in indications used to monitor reactivity or affect reactivity control?

6. Does the activity place a system in a configuration that places the unit in a Reduced Inventory condition or could affect the ability to control Reactor Coolant System (RCS) Pressure and Inventory?

7. Does the activity place a system in a configuration that could affect Decay Heat Removal?

b. EPU does not have a significant effect on the reliability or availability of equipment used for shutdown conditions.

c. EPU does not have a significant effect on the availability of equipment or instrumentation used for contingency plans.

d. EPU does not affect the ability of the operator to close containment.

e. The outage risk management procedures establish defense-in-depth criteria for equipment important to safe shutdown operation conditions and also provide requirements for contingency planning, compensatory actions, and management oversight on an escalating scale based on a qualitative assessment of risk. The availability of equipment and personnel to respond to degraded conditions during an outage is an important element of shutdown risk management. Contingency plans can be used to maintain Defense-In-Depth if planned systems or equipment become unavailable, or to protect available equipment. In general, as the level of planned Defense-In-Depth decreases, the use of contingency plans increases. Contingency plans may take the form of mandatory prerequisite activities, procedures, changes to the schedule during the outage, or other appropriate direction. This criteria does not change for EPU or for managing risk during shutdown post EPU, the Defense-In-Depth is the concept of:

- Providing systems, structures and components to ensure backup of KEY SAFETY FUNCTIONS using redundant, alternate, or diverse methods.
- Planning and scheduling outage activities in a manner that optimizes safety system availability.
- Providing administrative controls that support and/or supplement the above elements.
- Ensuring that multiple instrumentation channels are available AND being monitored for Key Safety Function parameters, that is, RPV level and temperature (and others as determined by Operations Management).

The NMPNS outage strategy for risk is to plan, monitor and control outages such that the key safety functions are protected by a Defense-In-Depth strategy. Specific guidance for assessing Key Safety Functions during shutdown conditions includes the following:

1. Decay Heat Removal Capability Assessments for maintenance activities affecting decay heat removal capability should consider that the ability of systems and components to remove decay heat are dependent on a variety of factors, including the plant configuration, availability of other key safety systems and components, and the ability of operators to diagnose and respond properly to an event. For example, assessments of maintenance activities that impact the decay heat removal key safety function consider:

   Initial magnitude of decay heat.

   Time to boil.

   Time to core uncovery.

   Initial RCS water inventory condition (for example, filled, reduced, reactor cavity flooded, etc).

   RCS configurations (for example, RPV open/closed, recirculation nozzle plugs installed or loop isolation valves closed, vent paths available, temporary covers installed, main steam line plugs installed, etc).

   When any fuel is offloaded to the spent fuel pool during the refueling outage, the decay heat removal function will be at least partially shifted from the RCS to the spent fuel pool. When the core is completely offloaded with the SFP gates installed, the Decay Heat Removal function in the RCS is "Not Applicable." Assessments for maintenance activities should reflect appropriate planning and contingencies to address loss of SFP cooling.

   Any maintenance activities that will occur during plant shutdown/cooldown and startup must also be assessed to ensure the continued ability to remove decay heat as necessary.

2. Inventory Control Assessments for maintenance activities address the potential for creating inventory loss flow paths in BOTH the RCS AND the SFP. For example, maintenance activities associated with the main steam lines (for example, SRV removal, ADS testing, main steam isolation valve maintenance, and so forth) can create a drain down path for the reactor cavity and fuel pool. This potential is significantly mitigated through the use of main steam plugs.

   There are potential inventory loss paths through the Residual Heat Removal system (RHR) to the suppression pool when RHR is aligned for shutdown cooling.

   When the core is completely offloaded with the SFP gates installed, the Reactor Inventory Control function is "Not Applicable."

3. Power Availability Assessments consider the impact of maintenance activities on availability of electrical power. Electrical power is required during shutdown conditions to maintain cooling to the reactor core and SFP, to transfer decay heat to the heat sink, to achieve containment closure when needed, and to support other important functions.

   Assessments for maintenance activities involving AC power sources and distribution systems should address providing defense in depth that is commensurate with the plant operating mode or configuration.

   Assessments for maintenance activities involving the switchyard and transformer yard consider the impact on offsite power availability.

   AC and DC instrumentation and control power is required to support systems that provide key safety functions during shutdown. As such, maintenance activities affecting power sources, inverters, or distribution systems consider their functionality as an important element in providing appropriate defense in depth.

4. Reactivity Control involves maintaining adequate shutdown margin in the reactor core and the spent fuel pool. During periods of cold weather, RCS temperatures can also decrease below the minimum value assumed in the shutdown margin calculation. When in power operation or startup conditions, availability of the Standby Liquid Control System - SLCS is considered.

5. Reactor Inventory Letdown Control involves maintaining adequate letdown capability in the reactor cavity/vessel during shutdown. This allows for a means to control normal make up to the reactor cavity/vessel during outages.

6. Secondary Containment Maintenance activities involving the need for open containment should include evaluation of the capability to achieve containment closure in sufficient time to mitigate potential fission product release. Containment Closure Time shall be less than the Time to Boil Time. This time is dependent on a number of factors, including the decay heat level and the amount of RCS inventory available.

7. Fire Protection Water involves maintaining adequate fire water system availability during outages. Many work activities involve hot work during outages. This key safety function ensures that adequate fire water systems are available.

8. Primary Containment intervals included in the procedure are intervals when in power operation, startup, and hot standby condition, availability of Primary Containment must be considered. No maintenance activities jeopardizing the availability of Primary Containment are undertaken, until the unit has achieved cold shutdown condition.

Electrical Engineering

RAI C1

In Attachment 8, the licensee provided an evaluation of grid stability based on the EPU of NMP2. To account for seasonal variations in station performance, the maximum output of the station used for the grid stability study was 1380 MWe at 233 MVAR lagging (vs. 1368.9 MWe at 278 MVAR lagging). Provide a detailed discussion as to how the reactive output values are developed, including whether or not turbine-generator equipment conditions are factored into these values (de-rating). In addition, if turbine-generator equipment conditions (other than seasonal variations) during operation result in restrictions of generator output (real and/or reactive capability less than reactive capability curve), provide a detailed discussion as to how this information impacts the operational grid contingency analyses. Also, provide a detailed discussion regarding the capability of the main generator to supply reactive output in accordance with the reactive capability curve.

NMPNS Response RAI C1

Reactive output values used in the grid stability study were calculated using an assumed maximum gross generator output of 1380 MW and a power factor of 0.986. Based on the generator rating of 1399.2 MVA, the reactive output was calculated as follows:

$$\mathrm{Sin}(\cos^{-1} 0.986) \times 1399.22 \text{ MVA} = 233 \text{ MVAR}$$

In determining these values, turbine-generator equipment conditions that could result in a derate in real or reactive capability were not considered.

The operational grid contingency program will not be impacted by reduction in either real or reactive output power of the plant. Real and reactive power are continuously monitored by the grid operator and feed into a state estimator and real-time contingency analysis program. The contingency analysis program analyzes contingencies in real-time using actual operating parameters. Therefore, any reduction in plant output due to equipment conditions would be automatically factored into the contingency analysis program.

The nameplate rating of the generator is 1399.22 MVA at a power factor of 0.9. This corresponds to 1260 MWe and 610 MVAR. During normal operation, the reactive power is adjusted as requested by the grid operator based on system needs. The range of output varies within the capability curve, but averages approximately 178 MVAR. The ability of the generator to supply reactive output for higher demand, up to 500 MVAR, has been demonstrated during annual reactive power testing.

RAI C2

In Attachment 8 of the May 27,2009, LAR, the licensee states that because the EPU will be accomplished using the existing main generator and step-up transformers, there will be no change in the short circuit current contribution of NMP2 to system faults, and the overall system fault duty is not impacted. Provide *a detailed discussion as to the basis for that statement, including whether actual fault studies for overall system fault duty were conducted using the increased inertia constant for the new high pressure rotor.*

NMPNS Response RAI C2

Analyses performed for EPU concluded that the existing ratings for the unit generator and generator step-up transformers are sufficient to accommodate the increased power output. Therefore, the generator and step-up transformers are not being uprated, or replaced, for EPU.

A system fault current assessment for EPU was performed in accordance with the New York Independent System Operator (NYISO) Guideline for Fault Current Assessment. When evaluating short circuit currents on New York State transmission facilities, generators are modeled using subtransient saturated reactance. Transformers are modeled using leakage reactance and load-loss based resistances corresponding to the transformer tap ratio. Based on NYISO fault current assessment guidelines, increased turbine inertia does not contribute to the magnitude of a short circuit. For EPU, none of the generator or transformer data used in the short circuit assessment are changing. As a result, there will be no change in the in the magnitude of the short circuit current contribution of NMP2 to system faults.

Stability studies were conducted for EPU using the increased inertia constant for the new high pressure rotor and results demonstrate that under a severe fault with delayed clearing, the system remains stable with NMP2 modeled at full EPU output.

RAI C3

Provide a list and description of components being added to your 10 CFR 50.49 program due to the proposed EPU (if applicable). Confirm that these components are qualified for the environmental conditions they are expected to be exposed to.

NMPNS Response RAI C3

The proposed EPU does not add of any components that are in the scope of the 10 CFR 50.49 program.

RAI C4

In Attachment 3 of the May 27, 2009, LAR, the licensee states that shielding will be installed to reduce post-accident dose to components in Group III, enough to extend the qualified life sufficient to meet environmental qualification (EQ) program requirements. Provide a detailed discussion of the specific shielding designs addressing how a 32% reduction (minimum) in exposure is achieved, and the resulting doses to Group III equipment (demonstrating qualification of said equipment).

NMPNS Response RAI C4

Shielding will be installed in equipment zones SG261355 and SG261356 to reduce the post-accident dose to these components sufficient to meet EQ program requirements. Shielding will be installed between the filters and the affected components. This shielding will be sufficient to reduce the post-accident radiation exposure from the filters by a minimum of 32%.

The additional shielding is steel plates installed in the line of sight between the radiation sources (SGTS filters) and the electrical components being protected. Additional shielding is provided for the following components:

Control Panel 2GTS*PNL30A (and components contained inside the panel)

Transformer 2GTS*XD1B

The required and approximate design dose reductions for each shield are:

Component	Qualified Dose (Rad)	EPU Dose (Accident Plus Normal Operation) without Supplemental Shielding (Rad)	EPU dose with Supplemental Shielding (Rad)	% Reduction	Provisions for Achieving the Dose Reduction
Control Panel 2GTS*PNL30A including components inside Panel 30A	1.10E+06	1.38E+06	8.39E+05	39%	A 5/8" thick steel plate is placed about 3 feet in front of the panel in the lines of sight between the panel and the SGTS filters.
Transformer 2GTS*XD1B	1.10E+06	1.20E+06	7.12E+05	41%	This transformer is shielded with 3" of steel. An additional 3/8" thick steel plate is attached to the existing steel shield to increase the total thickness to 3.375".

RAI C5

In Attachment 3, the licensee provided a worst case Plant EQ Enveloping Temperature profile for all zones and elevations. Provide a more detailed discussion and profiles, addressing accident pressure and humidity for all zones and elevations.

NMPNS Response RAI C5

Inside Containment:

LAR Figure 2.3-1 is based on the primary containment drywell post LOCA profile. This profile is also the worst case EQ enveloping profile for all plant EQ zones in the primary and secondary containment.

Pressure inside containment:

EPU post accident pressures inside containment have been analyzed and are shown in attached the Figure C5-1 . EPU impact on containment analyzed pressure is minor and does not impact the EQ envelope. Therefore, qualification for pressure inside containment is not impacted by EPU.

Humidity inside containment:

Humidity during LOCA events inside containment typically reaches saturation (100% and condensing) early in the transient and remains saturated for most if not all of the analyzed period. Because of this characteristic, humidity is typically not graphed. The EQ program assumes saturated conditions for the duration of the LOCA event, therefore, EPU has no impact on the EQ qualification to humidity.

Outside Containment:

High Energy Line Break (HELB) Temperature, Pressure, Humidity

Similar to the analysis for inside containment, the EQ Program assumes saturated conditions for the duration of the HELB event, therefore, EPU does not impact the qualification to humidity.

The HELB analyses for the secondary containment evaluated numerous break locations and sizes occurring in the RCIC and Reactor Water Cleanup (RWCU) Systems and also define which areas outside containment are not affected by a HELB. The impact of operating at EPU conditions was evaluated based on the mass and energy releases and the analytical bases used in NMP2 HELB analyses. Several areas were identified where the post EPU pressure profiles will change, such as the Main Steam Tunnel, RWCU Filter/Demineralizer, and RWCU Holdup Pump Rooms.

The EQ Program HELB temperature, pressure and humidity conditions for the Main Steam Tunnel and adjacent Turbine Building areas were evaluated at worst case conditions based on the various line breaks occurring in the Main Steam and Feedwater systems. The evaluation concluded that current values used for sub compartment temperature and pressures remain bounding for operation at EPU conditions. For the Main Feedwater Line Break (FWLB), the change in mass and energy at various EPU conditions will not increase FWLB temperatures and pressures above current Main Steam Line Break conditions in the Main Steam Tunnel such that the impact to EQ remains unchanged.

The RWCU Filter/Demineralizer and Holdup Rooms analysis concludes that the pressures created during a HELB under EPU conditions are still bounded by the current design basis profiles.

Therefore, the temperatures and pressures in EQ Program basis remain unchanged and EPU has no impact on the EQ Program and the design inputs used by the Program to define HELB temperature, pressure and humidity conditions. Copies of the pressure profiles for the Main Steam Tunnel and the RWCU Filter/Demineralizer and Holdup Rooms are attached as examples of the pressure curves.

[[**Figure C5-1** **EPU Containment Pressure Response to DBA-LOCA – SC06-01 Case**

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Reactor Systems

RAI D1

Figure 2.8-22 provides a plot of the main steam isolation valve closure with flux scram transient. The Vessel Pressure Rise is plotted in pounds per square-inch (psi), but scaled in percent rated (of something). Please quantify the bases, e.g., rated power (MWth) or nominal pressure (psi), for the plots of Vessel Pressure Rise and other parameters in this Figure.

NMPNS Response RAI D1

The vessel pressure curve on the plot in question is not scaled to a percentage basis, but is simply given in terms pressure rise (in psi) from its initial value (1050 psia). This is specified in the legend entry for the pressure plot. The other parameter plots on the figure are shown in terms of percent of rated vessel steam flow.

RAI D2

Explain why the vessel steam flow is oscillating while all other parameters appear to hold comparatively steady throughout the main steam isolation valve closure with flux scram transient.

NMPNS Response RAI D2

The ODYN computer code is capable of modeling steam line dynamic behavior. The model captures the effect of the pressure wave traversing between the Main Steam Isolation Valve (MSIV) and the reactor dome plenum region. This pressure wave phenomenon is the cause of the vessel steam flow oscillations. Although the steam flow oscillates, the trend in total steam flow vs. time decreases towards zero, which causes the vessel dome pressure to increase. There are small inflections in the reactor vessel pressure that correspond to the timing of the steam flow oscillations. The perturbation occurs again when SRVs lift and flow settles to the SRV flow rate.

RAI D3

Summarize the results of the plant-specific loss of feedwater (LOFW) analysis.

(a) *Address the modeling tool used, describe the sequence of events, discuss any additional failures assumed - beyond the high-pressure coolant injection (HPCI) - in the analysis and provide plots of the significant parameters to demonstrate performance relative to the applicable acceptance criteria.*

(b) *Compare analytic assumptions to those used in the current licensing basis (CLB). If applicable, provide equipment out-of-service assumptions used in this analysis and discuss whether these assumptions change in the EPU analysis as compared to the CLB analysis.*

(c) *Verify that any proposed changes in the Technical Specifications (TSs) will reflect the analysis assumptions used in the EPU analyses.*

NMPNS Response RAI D3

(a) From PUSAR Section 2.8.5.2.3:

As described in the PUSAR, Table 1-1, for Transient Analysis, the modeling tool used is the SAFER04 model, which is the same model used in the ECCS LOCA analysis. The analysis is done consistent with NRC-approved GEH LTR, NEDC-33004P-A. The general sequence of events in the analysis is as follows. The reactor is assumed to be at 102% of the EPU power level when the LOFW occurs. The initial level in the model is conservatively set at the low-level scram setpoint and reactor feedwater is instantaneously isolated at event initiation. Scram is initiated at the start of the event. When the level decreases to the low-low level setpoint, the RCIC system is initiated. The RCIC flow to the vessel begins at 68 seconds into the event, minimum level is reached at 1007 seconds and level is recovered after that point. Only RCIC flow is credited to recover the reactor water level. There are no additional failures assumed beyond the failure of the High Pressure Core Spray (HPCS) system. The only other key analysis assumption for the LOFW analysis, discussed in Section 9.1.3 of NEDC-33004P-A, was the assumed decay heat level of ANS 5.1-1979 with a two-sigma uncertainty. The assumed decay heat level for the EPU analysis was ANS 5.1-1979 decay heat + 10%, which bounds ANS 5.1-1979 + two sigma. Thus, the key analytical assumptions are the same or conservative relative to the current licensing basis. This LOFW analysis is performed to demonstrate acceptable RCIC system performance. The design basis criterion for the RCIC system is confirmed by demonstrating that it is capable of maintaining the water level inside the shroud above the top of active fuel during the LOFW transient. The minimum level is maintained at least 153 inches above the top of active fuel (see PUSAR Figure 2.8-23), thereby demonstrating acceptable RCIC system performance. There are no applicable equipment out of service assumptions for this transient.

(b) One minor change in the analytic assumptions for the LOFW event involves the modeling of the MSIV closure. The CLB analysis models isolation on low-low level (L2), while the EPU analysis applies the low-low-low level (L1) setpoint. The latter assumption is consistent with the NMP2 plant configuration. The MSIV closure would not substantially affect the loss of vessel inventory, which is a function of the decay heat and boil-off rate. With the MSIVs closed, some of the decay heat energy goes into pressurizing the reactor to SRV setpoints instead of inventory loss.

As stated above, there are no applicable equipment out of service assumptions for this transient. This is the case for both the CLB and EPU analyses.

(c) There are no proposed TS changes related to the LOFW analysis.

RAI D4

Provide plots for the limiting ATWS event (for both EPU and current licensed thermal power (CLTP) conditions) consistent with Tables 2.8-5 and 2.8-6 of NEDC-33351P, which show the bottom vessel pressure and indicate when the Standby Liquid Control (SLC) System starts injecting.

NMPNS Response RAI D4

Since the NMP2 SLCS injects through the HPCS sparger, the more appropriate parameter is the upper plenum pressure. This parameter is shown in Figures D4-1 and D4-2 for the limiting ATWS events with respect to vessel overpressure at CLTP and EPU conditions, respectively.

Figure D4-1 PRFO ATWS – CLTP EOC – NMP2

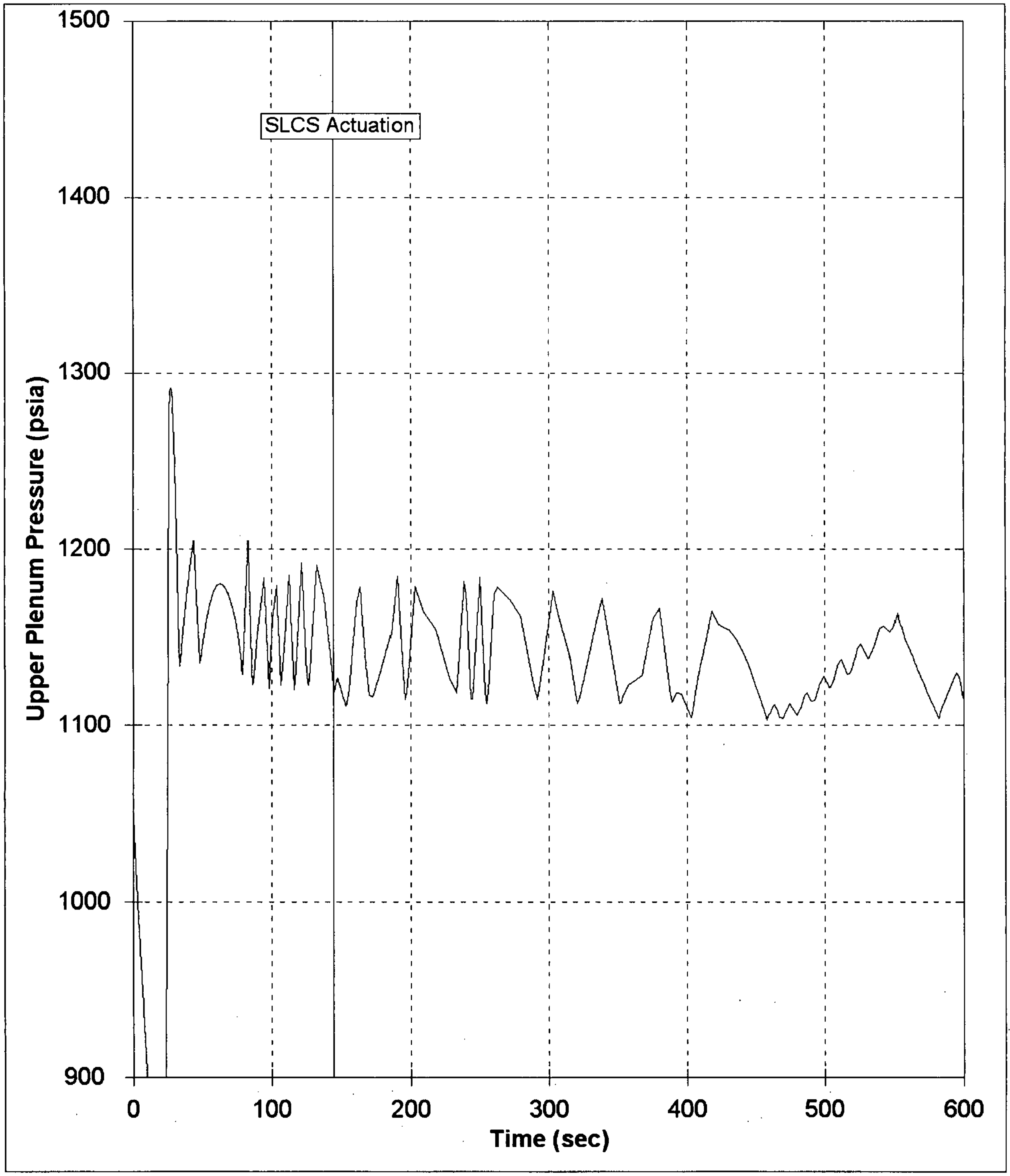
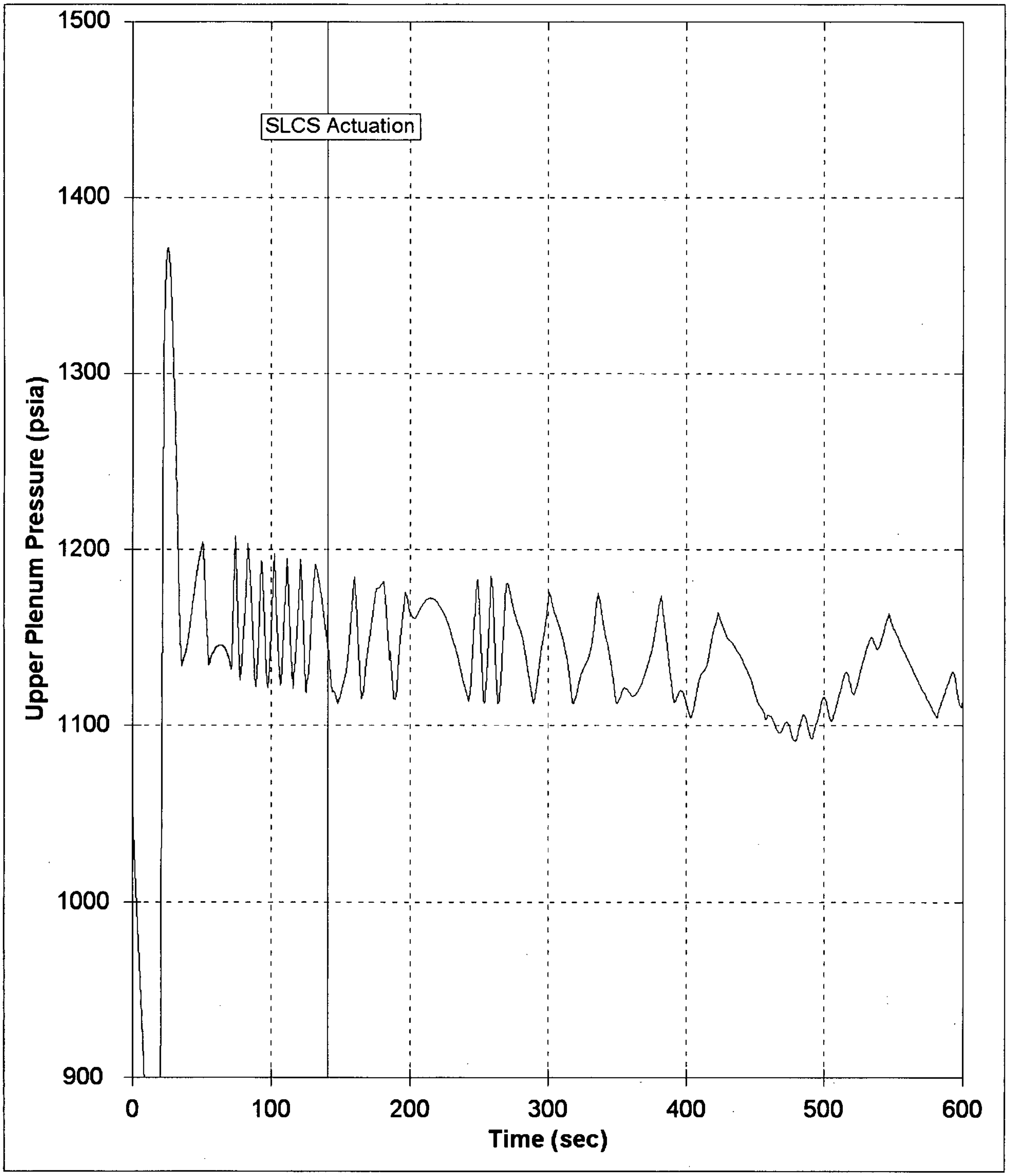


Figure D4-2 PRFO ATWS – EPU EOC – NMP2



RAI D5

With respect to the ATWS analysis results, indicate when the emergency core cooling system (ECCS) begins to deliver flow, and evaluate its effect upon core boron concentration and core reactivity.

NMPNS Response RAI D5

No ECCS actuation is explicitly credited in the NMP2 ATWS analysis. The approved ATWS analysis methodology (NEDC-24154P-A Supplement 1, Volume 4) credits operator action to control vessel level at 5 feet above the top of active fuel (TAF + 5'). This level control strategy is independent of the source of the makeup system (Feed Water (FW), RCIC, CRD, or ECCS). For modeling simplicity, the analysis assumes that vessel water level is maintained using the FW control system. However, the makeup flow is conservatively assumed to be at a relatively cold temperature consistent with Condensate Storage Tank (CST) conditions.

RAI D6

Table 2.8-12 of NEDC-33351P shows the Boral rack results based on zero degradation penalty. Are there any Boraflex racks in use at NMP2 to store new or spent fuel?

NMPNS Response RAI D6

There are no Boraflex racks in use at NMP2.

RAI D7

Does the maximum k-effective (k-eff) shown in Table 2.8-12 of NEDC-33351P account for the limiting accident scenario? What is the limiting accident considered?

NMPNS Response RAI D7

The maximum k-effective shown in Table 2.8-12 of NEDC-33351P is based on an infinite array of storage cells, loaded with the most reactive lattice analyzed, and did not incorporate any radial or axial leakage. This configuration bounded the accident conditions considered, which were:

1. Lateral Movement of a Rack Module,

2. Misplacement of a Fuel Assembly, and

3. Dropped Assembly.

RAI D8

Show that the analysis of the limiting accident scenario considered the bounding depletion parameter values relative to projected EPU operating conditions. The response should consider the effects of applicable depletion parameters, such as the moderator density, fuel temperature, specific power and operating history, and burnable poisons.

NMPNS Response RAI D8

The most reactive lattice used in the analysis (Design Basis Lattice) is based on TGBLA06A standard hot uncontrolled depletions, with appropriate in-core cold, xenon-free restart cases performed to identify the cold, exposure-dependent peak eigenvalues. The TGBLA06A Lattice depletions took into account the following conditions/parameters:

1. Uncontrolled State

2. Integral burnable poisons

3. Fuel Temperature

4. Moderator Temperature

5. Moderator Density

6. Power Density

7. Void Fractions

The Design Basis Lattice selection process includes studies on a number of extreme lattice designs to satisfy the spent fuel storage rack eigenvalue criteria. The Design Basis Lattice bounds all current reactor lattices and limits future EPU lattices.

RAI D9

What methods and analytic codes will be used to evaluate the LOFW heating (LOFWH) for EPU reload licensing analyses at NMP2?

NMPNS Response RAI D9

Loss of feedwater heating cycle-specific EPU reload licensing analyses will be performed with the NRC approved methods described in the GESTAR II LTR (NEDE-24011-P-A AND NEDE-24011-P-A-US). The computer code used to evaluate the loss of feedwater heating is PANACEA, as documented in NEDE-30130P-A.

RAI D10

Evaluate the LOFWH transient at EPU conditions at NMP2 to demonstrate conformance to fuel thermal-mechanical acceptance criteria. Provide transient results including those pertaining to fuel thermal mechanical performance, and specifically address the potential for pellet-cladding interaction and pellet-cladding mechanical interaction.

NMPNS Response RAI D10

Cycle-specific reload licensing analyses will be performed for NMP2. However, an analysis was performed at EPU/Maximum Extended Load Line Limit Analysis (MELLLA) conditions for a representative core and the results show acceptable margin [[
]]

The current licensing criteria applicable to RAI D10 are [[
]]. These criteria also apply to RAI E6. Additionally, the current licensing criterion that cladding fatigue life usage be less than or equal to 1.0 applies to RAI E6. These criteria are addressed in this response. This response also addresses the issue of the potential for increased pellet-cladding interaction (PCI) raised in RAIs D10 and E6. Since design or licensing criteria for PCI currently do not exist, the issue is addressed qualitatively in terms of impact on reliability.

A thermal-mechanical based power-exposure limits envelope is specified [[

]] The LHGR limits are specified to assure compliance with several primary fuel rod thermal-mechanical licensing criteria; these criteria address fuel centerline temperature, [[
]], and fuel rod internal pressure. [[

]]

A major GNF fuel rod design objective is to specify the LHGR limits curves to achieve balanced margins and a balanced design with high reliability over the rod lifetime.

During the core design process, a specified margin is typically maintained between the LHGR limits and the anticipated operation for each bundle. Operation under power uprate conditions will result in more rods in some bundles operating near the specified margin for a larger fraction of the bundle lifetime, thus increasing the potential for fuel failure. The potential for increased failure under power uprate conditions specified in Reference D10-1 is assessed in terms of available GNF operational experience and experimental information below. The impact of power uprate on thermal-mechanical licensing analyses for the GE14 fuel design is also discussed below.

[[

]] The results from this Severe Power Ramp testing, as compared to the LHGR limits curves for the fuel designs noted above, are also provided in Figure D10-1. It is observed from Figure D10-1 that significant margin exists to the apparent failure threshold represented by the available ramp test results. In addition to barrier fuel's resistance to ramping, ramp rates at power uprate conditions versus non-power uprate conditions are not appreciably different. Thus, it is judged that the possible increased cladding mechanical duty associated with operation under power uprate conditions will have negligible impact on the reliability of GNF fuel. It is further noted that the margin to failure is reasonably well-balanced over the entire exposure range, consistent with the design objective noted above.

In addition to possible increased fuel duty, other possible effects of power uprate are small changes in core conditions such as increased coolant pressure (and temperature) and changes in flow conditions. [[

]] Specific questions relative to the NMP2 LOFWH transient and instability oscillations for EPU are addressed below.

The current licensing criteria [[ ]] are satisfied for the LOFWH transient indicated in RAI D10. These criteria are based upon preventing wide spread cladding failures during the transient. For instability oscillations indicated in RAI E6, the incremental fatigue usage due to the oscillations is negligible in an absolute sense and relative to the margin to the limit (1.0) calculated for the cyclic loading assumed in the fuel rod thermal-mechanical licensing analyses. This criterion is based upon preventing wide spread cladding fatigue failures during normal operation. For NMP2, the peak maximum fraction of linear power density (MFLPD) [[

]] which is below the Apparent Failure Threshold in Figure D10-1. This value also bounds the peak MFLPD experienced during instability oscillations. These results indicate that the LOFWH transient and instability oscillations will have negligible impact on fuel reliability.

In summary, on the basis of the generic licensing analyses and the specific analyses to address operation under power uprate conditions summarized above, it is concluded that the [[ ]] fuel designs are fully compliant with existing licensing requirements for operation under power uprate conditions. Based upon available operational experience and experimental data, it is also concluded that operation under power uprate conditions will not significantly affect GNF fuel reliability.

References:

D10-1. Dresden and Quad Cities Extended Power Uprate, GE-NE-A22-00103-02 Revision 0, August 2000.

D10-2. H. Sakurai, et. al., "Irradiation Characteristics of High Burnup BWR Fuels" paper presented at the ANS Light Water Reactor Fuel Performance Conference held at Park City, Utah, April 10-13, 2000.

Figure D10-1
LHGR Limits and Severe Ramp Test Failure Data

[[

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RAI D11

What methods and analytical codes will be used to analyze the Rod Withdrawal Error event both at low-power and at power for the NMP2 EPU reload licensing analysis?

NMPNS Response RAI D11

The rod Withdrawal Error (RWE) at startup analysis is not performed on reload licensing basis, but is based on a generic study, NEDO-23842, that concludes it is a non-limiting event. The methods applied in the generic study are consistent with those for the Control Rod Drop Accident (CRDA) Rod Drop Accident Analysis for Large Boiling Water Reactors, Licensing Topical Report, March 1972 (NEDO–10527) including Supplements 1 and 2. There was no updated analysis performed since no change in peak fuel enthalpy is expected due to EPU because the RWE at startup is a localized low-power event. However, indirectly, EPU fuel and core designs can lead to generally higher rod worth distribution and therefore higher peak fuel enthalpy at low power. This indirect effect is not significant because the fuel and core design remain constrained by other factors such as shutdown margin and in-sequence rod worths. If the peak fuel rod enthalpy is conservatively increased by a factor of 1.2, the RWE at startup peak fuel enthalpy at EPU will be 72 cal/gram. This enthalpy is well below the acceptance criterion of 170 cal/gram.

Cycle-specific EPU reload licensing analyses of the RWE at power will be performed with the NRC approved methods described in the GESTAR II LTR. The computer code used in the analysis is PANACEA, as documented in NEDE-30130P-A.

RAI D12

What methods and analytical codes will be used in the reload licensing analysis to predict the fuel and system response to a Control Rod Drop Accident at EPU conditions?

NMPNS Response RAI D12

The CRDA evaluation is not performed on reload licensing basis, but is based on a generic study, NEDO-21231, "Banked Position Withdrawal Sequence," January 1977, that concludes it is a non-limiting event. The methods applied in the generic study are consistent with those for the CRDA Rod Drop Accident Analysis for Large Boiling Water Reactors, Licensing Topical Report, March 1972 (NEDO–10527) including Supplements 1 and 2. There was no updated analysis performed since no change in peak fuel enthalpy is expected due to EPU because the CRDA is a localized low-power event. However, indirectly, EPU fuel and core designs can lead to generally higher rod worth distributions and therefore higher peak fuel enthalpy at low power. This indirect effect is not significant because the fuel and core design remain constrained by other factors such as shutdown margin and in-sequence rod worths. If the peak fuel rod enthalpy is conservatively increased by a factor of 1.2, the CRDA peak fuel enthalpy at EPU will be 162 cal/gram. This enthalpy is well below the acceptance criterion of 280 cal/gram.

RAI D13

Do the calculated cladding oxidation levels account for pre-existing oxidation? If not, what amount of pre-existing oxidation will exist on the limiting bundle? How much pre-existing oxidation will exist on the more highly exposed bundles? Does the transient oxidation result presented consider oxidation on both surfaces of the fuel cladding?

NMPNS Response RAI D13

NRC Information Notice 98-29 addresses concerns regarding pre-transient oxidation in the ECCS-LOCA Evaluation Model. This matter was reviewed with respect to the General Electric-Hitachi (GEH) ECCS-LOCA evaluation model during the GNF Technology Update of April 29-30, 2008. No NRC review was requested since the conservative treatment presented would not fundamentally change the approved methodology.

The conclusion of that review was that GEH would not include pre-existing oxidation in the ECCS-LOCA calculation unless there was real prospect that the acceptance criterion (17% local oxidation limit) could be challenged. (This vulnerability would be principally seen on BWR/2 plants, only; these plants now include pre-transient oxidation on ECCS-LOCA analysis on a forward fit basis.)

Therefore:

a. Pre-existing oxidation is not considered in the calculated cladding oxidation levels reported from the analysis for NMP2 EPU.

b. The amount of pre-existing oxidation that will exist on the limiting bundle will be [[ ]] equivalent cladding reacted.

c. The generic assessment for GE14 fuel shows no more pre-existing oxidation will exist on the more highly exposed bundles than [[ ]]. This value bounds the pre-existing oxidation for the most highly exposed bundle for NMP2. Considering the calculated transient oxidation reported in the analysis, it is concluded ample margin remains to the 17% Acceptance Criterion, [[ ]]

d. The inside surface of the rod cladding is considered in the total calculation of transient oxidation. Oxidation on the inside surface of rod cladding is considered for times after perforation of the fuel rod. This treatment is consistent with the general ECCS-LOCA analysis methodology as coolant water becomes capable of ingress and contact with the fuel rod inside surface.

RAI D14

In Section 2.8.4.4, it is stated that, "containment pressures for EPU events increased slightly above the CLTP analyzed pressures, but remained below the existing TS peak containment internal pressure, Pa." What is the value that precedes Pa?

NMPNS Response RAI D14

As stated in PUSAR Section 2.2.4, "Safety-Related Valves and Pumps:"

"Tests that measure containment isolation valve leak rates (Type C tests) are performed using the Technical Specification value for Pa of 39.75 psig. From the containment analysis at the EPU conditions, the peak containment pressure is 52.9 psia (38.2 psig) for a LOCA (PUSAR Section 2.6.1)."

After submittal of the NMP2 EPU LAR, GEH issued Safety Communication SC09-05 which documents an analysis deficiency in the design basis containment analysis impacting the peak drywell pressure. The GEH safety communication concluded that the peak pressure remains less than the NMP2 drywell structural design limit of 45 psig and less than the analysis pressure of 39.75 psig (Pa). Therefore, the analysis deficiency has no impact on the NMP2 primary containment design function for CTLP.

NMPNS is currently evaluating the potential impact to the NMP2 EPU LAR from SC09-05 through the NMPNS corrective action program. Should there be an impact, NMPNS will communicate the results to NRC.

RAI D15

In Section 2.8.4.6, it is stated that, "the NMP2 recirculation loop jet pump flow mismatch TS limits do not change because these limits are based on rated core flow, which is not affected by EPU, and the flow mismatch limits are not affected because a detailed ECCS evaluation was not required." Describe how it was determined that a detailed ECCS evaluation was not required.

NMPNS Response RAI D15

The Constant Pressure Power Uprate (CPPU) Licensing Topical Report (LTR) (Reference below) describes conditions on which detailed ECCS analysis is not required. Section 4.3 states as a basis that ECCS performance characteristics will not be changed for CPPU. Further, the reference mentions other factors significant to the ECCS-LOCA analysis such as the basic break spectrum response (limiting break location), fuel conditions (including fuel type and thermal limits of the hot bundle power: (Minimum Critical Power Ratio (MCPR), Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) and LHGR), along with limiting single failure, all of which would be unchanged for CPPU.

For the NMP2 EPU application, there are no changes to ECCS flow rates, setpoints, emergency diesel generator initiation sequence timing or assumptions as to available equipment from the base SAFER/GESTR analysis of record. Nor are there changes to the other conditions noted. On that basis, it was concluded the NMP2 EPU application complies with the CPPU LTR Safety Evaluation Report (SER); detailed ECCS-LOCA evaluation is not required.

Reference:

GE Nuclear Energy, "Constant Pressure Power Uprate," NEDC-33004P-A, Revision 4, Class III (Proprietary), July 2003; and NEDO-33004, Class I (Non-proprietary), July 2003 - Section 3.6 page 3-11

RAI D16

If screening criteria are employed in the reload analyses, provide these screening criteria. If screening criteria are exceeded on a cycle-specific basis, what recourse is taken to demonstrate compliance?

NMPNS Response RAI D16

Screening criteria for core physics or plant operating parameters are not employed in the reload transient analysis. Cycle-specific analyses of the limiting transient events are performed according to the methods described in the GESTAR II LTR (NEDE-24011-P-A AND NEDE-24011-P-A-US) using as-loaded core design information and updated plant operating parameters.

RAI D17

Indicate whether credit was taken for containment backpressure in the loss-of-coolant accident (LOCA) analyses of record, and whether the said credit will be used in the EPU LOCA analyses.

NMPNS Response RAI D17

The NRC approved SAFER/GESTR-LOCA methodology assumes the drywell pressure is constant at 14.7 psia throughout the LOCA event. This assumption [[ ]].

Therefore:

a. The containment backpressure is not credited in the LOCA analyses of record.

b. The containment backpressure is not credited in the NMP2 EPU LOCA analyses. The 14.7 psia constant ambient pressure is assumed throughout the LOCA event.

Thermal and Hydraulic Design

RAI E1

With respect to the proposed EPU, provide a description of:

(a) the implementation status of the Long-Term (L/T) Stability Solution in NMP2, and any effects or impacts of the EPU on the L/T stability implementation.

(b) the power range neutron monitoring system, oscillation power range monitor(OPRM) operability and surveillance requirements, and the backup stability protection (BSP) implementation in NMP2.

(c) the NMP2 OPRM operating experience and the lessons learned from the 2003 instability event.

NMPNS Response RAI E1

(a) In April 2000, NMP2 implemented the Long Term Stability Solutions (No methods changes for EPU):

- Backup stability implementation (e.g. Interim Corrective Actions (ICAs)) retained in procedures
- Maximum rod line remains the same (ELLLA on implementation, the plant now uses the MELLLA boundary)
- Cycle specific setpoint analysis will capture core design variations
- Full core of GE-14 fuel
- Option III L/T Stability Solution remains unchanged, except for cycle specific OPRM setpoints
- Option III OPRM setpoints will be developed based on plant specific Delta CPR / Initial CPR Versus Oscillation Magnitude (DIVOM) curves for the EPU cycle specific reload analysis.

(b) For EPU the changes to the Power Range Neutron Monitoring System (PRNM), OPRM and BSP are discussed in the LAR enclosure, TS markup Attachment 1, and Section 2.4 and Table 2.4-1 of the Attachment 11 of the submittal.

(c) NMP2 experienced an OPRM scram on valid signal in 2003:

- The post scram evaluation determined inappropriate confirmation count resets occurred prior to scram. Subsequently, NMPNS:
  - Implemented GE Safety Communication SC 03-20
  - Changed the OPRM filter frequency setting from 3 hertz to1 hertz
  - Changed the period tolerance from 50 mseconds to 100 mseconds

RAI E2

For the BSP calculations, describe how the stability curves for scram region and controlled entry region shown in Figure 2.8-21 of NEDO-33351P are calculated for EPU conditions. Specifically, provide the associated feedwater temperature assumptions that allow the use of the same decay ratio criteria shown in Table 2.8-2 for the scram and exit boundary.

NMPNS Response RAI E2

The BSP Scram and Controlled Entry region for Option III methodology are calculated in the fuel cycle reload stability analysis. The same methodology is applied for EPU. To calculate the BSP Scram and Controlled Entry Region boundaries, ODYSY decay ratio calculations are performed on the highest licensed flow control line and on the natural circulation line. Rated feedwater temperature and rated xenon concentrations are assumed for calculating the BSP Scram Region boundary points, and the points where a 0.8 core wide decay ratio is calculated are connected using well defined Shape Function (i.e. Generic or Modified Shape Function) to define the Scram region boundary. The BSP Controlled Entry

Region is calculated in a similar manner, also using a core wide decay ratio of 0.8 to define the region boundary; the difference being that the decay ratio calculation of the point on the highest flow control line assumes equilibrium feedwater temperature at off-rated operating condition and xenon concentration (rather than rated), and the point on the natural circulation line assumes equilibrium feedwater temperature and xenon free conditions. This is why the two different curves can have almost identical calculated core wide decay ratios.

RAI E3

Will the Option III hardware implemented in NMP2 have the DSS-CD software installed for testing purpose? What are the testing plans?

NMPNS Response RAI E3

NMPNS is not currently scheduled to modify OPRM Option III hardware to include the Detect and Suppress Solution – Confirmation Density (DSS-CD) software. If and when NMPNS determines that DSS-CD software will be incorporated to the OPRM Option III hardware, all NMP2 and NRC programs and policies will be complied with for the implementation of the modifications.

RAI E4

Will the Delta CPR/Initial CPR Versus Oscillation Magnitude (DIVOM) curve be implemented as cycle-specific in NMP2? If the generic DIVOM slope will not be used, provide a reference to the cycle-specific DIVOM analysis methodology that will be used.

NMPNS Response RAI E4

The DIVOM slope will be evaluated on a cycle-specific basis per the Boiling Water Reactor Owners Group (BWROG) Regional DIVOM Guideline (GE-NE-0000-0028-9714-R1, "Plant-Specific Regional Mode DIVOM Procedure Guideline," June 2005). It will be limited to not less than the generic DIVOM slope of 0.45 as prescribed in NEDO-32465-A, "Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications," August 1996.

RAI E5

In September 2006, the Hope Creek plant experienced a half-scram indication from the Option III hardware while withdrawing peripheral control rods in low-power bundles. Hope Creek implemented recommendations for speed of rod withdrawal inside the armed region. Have these recommendations been incorporated in the NMP2 operator training?

NMPNS Response RAI E5

Recommendations to limit the speed of control rod withdrawal while in the OPRM trip enabled region have not been incorporated in the NMP2 operator training program. The Hope Creek recommendations have not been implemented at NMP2 due to the following:

1. Operational differences between the ASEA Brown Boveri (ABB) system hardware installed at Hope Creek during the 2006 event and the General Electric Nuclear Measurement Analysis and Control (NUMAC) Power Range Neutron Monitoring system installed at NMP2. (The ABB system in operation at Hope Creek at that time was more susceptible to spurious trip signals due to lower amplitude trip settings).

2. The recommendation to limit control rod withdraw speed was intended as an interim action until the OPRM amplitude trip settings were increased. NMP2 OPRM amplitude trip settings were significantly higher than Hope Creek's; thereby rendering the interim action unnecessary.

RAI E6

Assuming a conservative OPRM setpoint of 1.15, provide the hot-spot fuel temperature as function of time before the scram. Evaluate this fuel temperature oscillation against pellet-clad interaction (PCI) limits. Assume the steady-state fuel conditions before the oscillations are those of point ICA-A1 of Figure 2.8-21 of NEDC-33351P (the highest power point in the BSP scram region).

NMPNS Response RAI E6

See Response to RAI D10.

RAI E7

Provide plant-specific information relevant to ATWS, specifically:

(a) location of the boron injection

(b) a description of the SLC system actuation logic and its operability requirements

(c) boron enrichment level

(d) turbine bypass capacity

(e) location of the steam extraction points for FW heaters

NMPNS Response RAI E7

The equipment performance parameters used in the NMP2 ATWS analysis are provided below:

(a) Boron injection through the HPCS sparger

(b) SLCS operation initiated 120 seconds after ATWS recirculation Pump Trip (RPT) (automatic actuation would occur on Redundant Reactivity Control System (RRCS) signal). Two SLC subsystems must be operable per TS Limiting Condition for Operation (LCO) 3.1.7.

(c) B10 enriched to at least 25%

(d) Turbine bypass capacity of 18.5% of rated vessel steam flow at rated 991 psia throttle pressure (not credited in ATWS analysis)

(e) Steam extraction points for FW heaters are listed below:

4th stage to 6th point heaters
8th stage to 5th point heaters and Moisture Separator Reheaters (MSRs)
9th stage to 4th point heaters
10th stage to 3rd point heaters
12th stage to 2nd point heaters
14th stage to 1st point heaters

RAI E8

Provide a summary of the ATWS emergency operating procedure (EOP) actions. Provide justification that the EOPs are sufficient to suppress potential thermal-hydraulic instabilities during ATWS events.

NMPNS Response RAI E8

A summary of the ATWS EOP actions follows.

N2-EOP-RPV, RPV Control

- Scram
  - Mode switch to SHUTDOWN
  - IF mode switch failure, THEN arm and depress pushbuttons
- IF more than one control rod > 00, THEN exit EOP-RPV and enter C5, Failure to Scram

N2-EOP-C5, Failure to Scram

- Prevent automatic initiation of ADS
- Prevent HPCS injection
- Prevent Main Turbine trip from RCIC if necessary

N2-EOP-C5, Failure to Scram (Power Leg)

- Place (confirm) reactor mode switch in SHUTDOWN
- Initiate RRCS (initiates Alternate Rod Insertion (ARI))
- Reduce reactor recirculation flow to minimum
- IF reactor power is above 4%, THEN trip the Reactor Recirculation pumps
- Insert control rods using ARI methods using N2-EOP-6, Attachment 14, Alternate Control Rod Insertions

  - Alternate Methods of Control Rod Insertion

    - Manual insert control rods using elevated drive pressure
    - Individually scram control rods at Hydraulic Control Units (HCUs)
    - Reset scram and scram again (hydraulic failure allows the Scram Discharge Volume (SDV) to drain)
    - Vent scram air header
    - De-energize scram solenoids
    - Vent (CRD) over piston volume

  - N2-EOP-6 Attachment 14 flowchart provides guidance for which alternate method to use based on CRD, Scram Air Header and RPS indications and status.

- IF power oscillating more than 25%, THEN inject boron
- BEFORE Suppression Pool temperature reaches 110°F (Boron Injection Initiation Temperature (BIIT)), inject boron

N2-EOP-C5 (Level Leg)

- IF level cannot be determined, THEN exit N2-EOP-C5 level and pressure and enter N2-EOP-C4, RPV Flooding
- IF condenser is available, THEN bypass Main Steam Isolation Valve (MSIV) low RPV water level isolation and Offgas high radiation isolation
- IF power is above 4% or unknown AND RPV level is above 100 inches, THEN lower level to 50 – 80 inches (uncover feedwater sparger)
- IF power is above 4% AND RPV level is above -14 inches (Top of Active Fuel (TAF)) AND an SRV is open OR Drywell pressure is above 1.68 psig AND Suppression Pool temperature is above 110°F (BIIT), THEN lower level until <4% power OR RPV level ≤ -14 inches OR all SRVs stay closed AND drywell pressure stays below 1.68 psig

- IF RPV level cannot be restored and maintained above -39 inches (minimum steam cooling water level), THEN enter N2-EOP-C2, RPV blowdown
- For injection sources, use preferred ATWS Systems (inject outside core shroud) before using alternate ATWS Systems (inject inside core shroud)

N2-EOP-C5 (Pressure Leg)

- IF Drywell pressure is at or above 1.68 psig, THEN before RPV pressure drops to 400 psig, prevent Low Pressure Core Spray (LPCS) and Low Pressure Coolant Injection (LPCI) (alternate ATWS Systems) injection not needed for core cooling
- IF Suppression Pool temperature will exceed the Heat Capacity Temperature Limit (HCTL), THEN maintain RPV pressure less than HCTL curve
- Stabilize RPV pressure below 1052 psig

N2-EOP-PC, Primary Containment Control

- No actions specific to ATWS
- Use Suppression Pool cooling mode of RHR to maintain temperature less than HCTL
- IF Suppression Pool temperature reaches 110°F, THEN enter N2-EOP-RPV, RPV Control
- IF Suppression Pool temperature cannot be maintained below HCTL or Suppression Chamber pressure cannot be maintained below pressure suppression pressure, then enter N2-EOP-C2, RPV Blowdown

N2-RPV-C2, RPV Blowdown (ATWS Leg)

- Terminate and prevent all RPV injection except Boron, CRD and RCIC
- Open 7 ADS valves
- Return to middle ATWS level leg of N2-EOP-C5

N2-EOP-C4, RPV Flooding (ATWS Leg)

- Terminate and prevent all RPV injection except Boron, CRD and RCIC
- Open 7 ADS valves
- When RPV pressure is less than Minimum Steam Cooling Pressure (MSCP), injection restored to maintain RPV pressure just above MSCP (6 to 10% reactor power)

The NMP2 EOPs are sufficient to suppress potential thermal-hydraulic instabilities during ATWS events for the following reasons. Note that the power, level and pressure legs are designed to be implemented concurrently. The order provided here is how the operator training program has trained operators to execute the EOPs for the best mitigation strategy.

1. Prevent High Pressure Core Spray (HPCS) injection and (ADS) initiation.

   In order to effect a reduction in reactor power, actions in N2-EOP-C5 may deliberately lower RPV water level to a level below the automatic initiation setpoint of ADS. Actuation of this system imposes a severe thermal transient on the RPV and complicates the efforts to maintain RPV water level within the ranges specified in EOP-C5. Further, rapid and uncontrolled injection of large amounts of relatively cold, unborated water from low pressure injection systems may occur as RPV pressure decreases to and below the shutoff heads of these pumps. Such an occurrence would quickly dilute in-core boron concentration and reduce reactor coolant temperature. When the reactor is not shutdown, or when the shutdown margin is small, sufficient positive reactivity might be added in this way to cause a reactor power excursion large enough to severely damage the core. Therefore, ADS initiation is purposely prevented as the first action of the failure to scram procedure. When required, explicit direction to depressurize the RPV is provided in the EOPs, thereby negating any requirement to maintain the automatic initiation capability of ADS.

The preferred injection systems in EOP-C5 are those that inject outside the core shroud. Positive action is therefore taken to preclude HPCS injection, since HPCS is capable of injecting into the RPV at any RPV pressure (unlike the low pressure ECCS), and if reactor power is above 4% or unknown, RPV water level will be lowered to below the HPCS initiation setpoint of 108.8 inches.

These actions will limit the initial power level and magnitude of thermal-hydraulic instabilities at the start of the ATWS event that may otherwise be worsened by automatic initiation of these systems.

2. Initial actions in N2-EOP-C5, failure to scram power leg, attempt to establish a control rod pattern that will maintain the reactor shutdown under all conditions without boron. These actions include:

   - Placing or verifying the reactor mode switch is in SHUTDOWN
   - Initiating the Redundant Reactivity Control System (RRCS), this in turn will initiate Alternate Rod Insertion (ARI) by venting the scram air header.

   When the reactor mode switch is placed in the SHUTDOWN position, a diverse and redundant reactor scram signal is generated by the Reactor Protection System (RPS) logic. Sets of contacts momentarily open which trip the RPS logic in the same manner as sensor or sensor relay contacts.

   Also, rotating the mode switch out of the RUN position prevents Main Steam Isolation Valve (MSIV) closure on low main steam line pressure, thus maintaining main condenser availability and minimizing the heat load on the containment.

   RRCS initiation independently (of RPS) depressurizes the scram air header and operates the scram discharge volume vent and drain valves. If reactor power remains above 4% following a 98 second time delay, Standby Liquid Control (SLC) system will be automatically initiated.

   These actions are simple, can be performed from the control room and if successful will eliminate thermal-hydraulic instability and terminate the ATWS stability event.

3. If reactor power is above four (4) percent and reactor water level is above 100 inches, than all injection sources except for (CRD), Boron and Reactor Core Isolation Cooling (RCIC) are terminated and prevented allowing reactor water level to drop below 100 inches. Then reactor water level is maintained in a band of 50 to 80 inches using preferred injection sources.

To prevent or mitigate the consequences of any large irregular neutron flux oscillations induced by neutronic/thermal-hydraulic instabilities, RPV water level is lowered sufficiently below the elevation of the feedwater sparger nozzles. This places the feedwater spargers in the steam space providing effective heating of the relatively cold feedwater and eliminating the potential for high core inlet subcooling. For conditions that are susceptible to oscillations, the initiation and growth of oscillations is principally dependent upon the subcooling at the core inlet; the greater the subcooling, the more likely oscillations will commence and increase in magnitude.

If reactor power is at or below the Average Power Range Monitoring (APRM) downscale trip setpoint, it is highly unlikely that core bulk boiling boundary would be below that which provides suitable stability margin for operation at high powers and low flows. (A minimum boiling boundary of 4 ft above the bottom of active fuel has been shown to be effective as a stability control because a relatively long two-phase column is required to develop a coupled neutronic/ thermal-hydraulic instability.) Furthermore, flow/density variations would be limited with reactor power this low since the core has a relatively low average void content. Therefore, there is significant stability margin with power at or below the APRM downscale trip setpoint.

Twenty-four inches below the lowest nozzle in the feedwater sparger (indicated RPV water level of 100 inches) has been selected as the upper bound of the RPV water level control band. This water level is sufficiently low that steam heating of the injected water will be at least 65% to 75% effective (i.e., the temperature of the injected water will be increased to 65% to 75% of its equilibrium value in the steam environment). This water level is sufficiently high that plants such as NMP2 without the capability to readily bypass the low RPV water level MSIV isolation should be able to control RPV water level with feedwater pumps to preclude the isolation.

Lowering RPV water level is accomplished by terminating and preventing all injection into the RPV, except from boron injection systems, RCIC, and CRD. Boron injection systems, RCIC, and CRD are relatively low flow systems. Boron injection systems and CRD may be needed to establish and maintain reactor shutdown conditions. When restoration of injection is subsequently required, but other outside shroud injection systems are incapable of injection, continued RCIC operation (along with boron injection systems and CRD) may prevent RPV water level from dropping to the level that requires an RPV Blowdown. The marginal decrease in the rate of water level reduction resulting from continued RCIC operation has a negligible impact on lowering core inlet subcooling.

With RPV injection terminated, RPV water level and reactor power decrease at the maximum possible rate allowed by boil off. Failure to completely stop RPV injection flow (with the exception of CRD, RCIC, and SLC) would delay the reduction in core inlet subcooling, thus increasing the potential for flux oscillations.

The process by which reactor power is reduced by lowering RPV water level occurs as follows:

a. The reactor is in a natural circulation mode following recirculation pump trip which occurs as RPV level is reduced below level 2, 108.8". The natural circulation driving head is a function of the fluid density difference between the regions inside and outside of the shroud (void fraction directly affects the fluid density inside the shroud) and the height of the fluid columns (RPV water level).

b. As RPV water level is lowered, the height of the fluid columns is reduced, thereby reducing the natural circulation driving head.

c. As the natural circulation driving head is reduced, the natural circulation flow through the core is reduced.

d. The reduced core flow results in a reduced rate of steam removal from the core.

e. The reduced rate of steam removal results in an increased void fraction inside the shroud.

f. The increased void fraction adds negative reactivity to the reactor.

g. The negative reactivity drives the reactor slightly subcritical and power begins to decrease.

h. The reduced reactor power results in a reduced steam generation rate.

i. The reduced steam generation rate results in a reduced void fraction.

j. When the void fraction drops to its original value (with some slight adjustment to account for reduced Doppler reactivity), the reactor returns to criticality at a lower power.

These interrelationships between RPV water level, natural circulation core flow, and reactor power have been observed in operating BWRs with RPV water level in or near the normal operating band. Computer analyses and scale model tests have confirmed the continued validity of these fundamental thermal-hydraulics and reactor physics principles for RPV water levels at and below the elevation of the steam separators.

Even in the absence of large irregular neutron flux oscillations induced by neutronic/thermal-hydraulic instabilities, power oscillations of relatively smaller magnitude may occur when RPV water level is lowered significantly below the normal operating range with the reactor still at power. Typically, the magnitude of these oscillations is below the Large Oscillation Threshold. These smaller oscillations have been analyzed and determined to result in thermal transients well within the design capabilities of the fuel. Oscillations are noted at this point to indicate to the operators that they are to be expected, and were considered in developing the steps which require deliberately lowering RPV water level with the reactor at power.

Under failure-to-scram conditions, systems that inject outside the core shroud are preferentially used since the cold, unborated injection will be mixed with warmer, borated water in the downcomer before reaching the core, thereby avoiding cold water reactivity transients.

4. Reduce Reactor Recirculation Pump to minimum and, if reactor power is above 4%, trip the Reactor Recirculation pumps. Note that this action is typically accomplished by lowering reactor water level in the level leg of N2-EOP-C5. It is discussed as a separate item to provide a complete response in terms of how the EOP actions are sufficient to suppress potential thermal-hydraulic instabilities during ATWS events.

An immediate and rapid reactor power reduction may be effected by reducing reactor coolant recirculation flow rate. This action may place plant operations in a high power to-flow condition where, under certain circumstances, neutronic/thermal-hydraulic instabilities are possible. However, the action to reduce recirculation flow rate remains appropriate because:

- Severe suppression pool heating and potential containment failure result if recirculation flow is not reduced.
- Neutronic/thermal-hydraulic instabilities can be accommodated without fuel failure in most cases.
- RPV water level control actions which are being performed in the Level Branch concurrently with the actions of this branch will prevent or mitigate the occurrence of extremely large neutronic/thermal-hydraulic instabilities which may damage the fuel.
- Subsequent reactor power control actions to inject soluble boron and insert control rods, if successful, will terminate the failure-to-scram condition, thus preventing prolonged exposure to instabilities.

The most rapid flow rate reduction and, consequently, the most rapid power reduction, is achieved by tripping the recirculation pumps. However, if the recirculation pump trip is initiated from a high power level, the resulting rapid changes in steam flow, RPV pressure, and RPV water level may cause a trip of the main turbine-generator and an initiation of RPV injection systems. If the main turbine-generator trips and reactor power exceeds the turbine bypass valve capacity, RPV pressure will increase until one or more SRVs open. Heatup of the suppression pool then begins and boron injection may ultimately be required. If the RPV injection systems initiate, the resultant RPV water level transient may require an RPV Blowdown and operation of less desirable RPV injection sources.

To effect a more controlled reduction in reactor power and thereby avoid main turbine generator and RPV injection system initiations and their associated complications, a recirculation flow run back is performed prior to tripping the recirculation pumps. If an automatic runback has occurred, the operator need only confirm the action.

If reactor power remains above 4% (the APRM downscale setpoint), the recirculation pumps are tripped to effect a prompt reduction in power. While tripping the pumps may place the plant in a high power-to-flow condition and thereby contribute to neutronic and thermal-hydraulic instabilities, continued recirculation pump operation may not be desirable or even possible:

- If RPV water level is lowered in accordance with the N2-EOP-C5 level leg as discussed above, the pumps will trip automatically when the RPV water level reaches 108.8 inches.
- Allowing reactor power to remain high would increase the flow demand on RPV injection systems and the heat load on the primary containment.

Tripping the recirculation pumps may also reduce the boron mixing efficiency if boron injection is required. However, three-dimensional scale model tests have demonstrated that natural circulation provides adequate mixing as long as RPV water level is above the elevation at which a natural circulation flowpath can be established.

If reactor power is below 4%, tripping the recirculation pumps results in little, if any, reduction in reactor power since power is already near the decay heat level. In this case, forced recirculation flow is continued, if possible, to enhance boron mixing if boron injection is later required.

5. Insert Control Rods using alternate rod insertion methods. The alternate methods address the following failure modes:

    - Reactor Protection System (RPS) logic failures
    - Scram air header venting failures
    - Control Rod Drive hydraulic failures

    The alternate rod insertion methods include actions for individual control rod insertion and full core scram. Individual control rod insertion is done in a manner that will reduce neutron flux from areas of high to low flux.

    Reactor shutdown on control rod insertion alone is preferable to injecting boron for the following reasons:

    - If a leak occurs below the elevation of the RPV water level being maintained, boron injection may not be successful in shutting down the reactor.

    - A reactor shutdown on boron is not necessarily a stable condition; if boron is subsequently diluted or displaced by a leak or an operational error, the reactor could return to criticality.

    - Boron injection contaminates the primary system requiring extensive cleanup and subsequent inspection before continued plant operation is possible.

    If control rods can be inserted sufficiently to shutdown the reactor, boron injection may be terminated or avoided altogether.

6. Inject boron. This action should have already occurred automatically, if required. A step to manually inject boron when predefined limits are reached and automatic boron initiation has not occurred is included in the EOP.

    Analyses of neutronic/thermal-hydraulic instabilities during failure-to-scram conditions have been performed. Instabilities are manifested by oscillations in reactor power which, if the reactor cannot be shutdown, may increase in magnitude. If the oscillations remain small or moderately sized, they tend to repeat on approximately a two second period. Under certain circumstances, however, the oscillations may continue to grow and become sufficiently large and irregular to cause localized fuel damage. The initiation and growth of these oscillations is principally dependent upon the subcooling at the core inlet. The greater the subcooling, the more likely that oscillations will commence and increase in magnitude. Although unlikely, it is possible for such oscillations to develop before corrective actions can be taken.

The process by which large irregular neutron flux oscillations can develop within a fuel bundle assembly occurs as follows:

a. Subcooled water enters the fuel bundle.

b. The resulting positive reactivity addition causes a rapid increase in bundle power.

c. The increased energy deposition in the fuel increases the fuel and clad temperature.

d. Doppler (fuel temperature) feedback terminates the power increase.

e. Higher clad temperatures increase the surface heat flux, generating steam and a pressure increase in the channel.

f. Moderator is discharged from both the top and bottom of the bundle with void generation rapidly decreasing power.

g. Inlet flow is restored by the lower plenum pressure/flow boundary conditions, and the process begins again.

Analytical results indicate that the fuel clad may experience boiling transition during this process, but that it subsequently rewets and is adequately cooled even for oscillations that resemble reactivity excursion events. For an occasional large pulse, however, rewetting of some of the highest powered locations within the highest powered fuel bundles may not occur; the clad could then continue to heat up over several oscillation cycles. The possibility of localized fuel clad failures cannot be precluded even though core geometry and core cooling are not significantly threatened. Propagation of the fuel clad failures to neighboring bundles is not expected and greater core damage is not likely for this condition.

To provide reasonable assurance that any rapidly growing oscillations are mitigated in a timely manner, boron is injected when neutron flux oscillations in excess of the Large Oscillation Threshold (LOT) commence and continue. The LOT is a peak-to-peak neutron flux oscillation amplitude equal to or less than 25% yet sufficiently large to be distinguishable from the flux perturbations expected of a stable thermal-hydraulic system. Flux oscillations at or below the LOT during a failure-to-scam event are not expected to threaten fuel clad integrity.

The direction to inject boron "before" suppression pool temperature reaches 110°F (the Boron Injection Initiation Temperature) also permits injection of boron before neutron flux oscillations are observed if it is clearly beneficial. Early boron injection is not *required,* however, since it may not always be appropriate or desirable. For example, if an RPV Blowdown must be performed with the core borated, the subsequent injection of cool, unborated water to restore RPV water level can dilute and displace hot borated water in the core region. The resulting positive reactivity change will be greater than that which would occur if the injected water displaced hot *unborated* water from the core region, since boron loss would not then be a factor. Premature boron injection could thus increase the potential for a reactivity excursion.

Initiation of boron injection is required for oscillations in excess of the LOT only if they "commence and continue." This wording clarifies that boron need not be injected in response to a single flux pulse which subsequently subsides.

For conditions susceptible to oscillations, the oscillation growth is directly related to core inlet subcooling. Since the length of time required to raise in-core boron concentration is longer than the time required to reduce core inlet subcooling, boron injection alone may not prevent large irregular neutron flux oscillations from occurring. However, the magnitude of the oscillations is reduced as the concentration of boron in the core increases.

For the great majority of failure-to-scram conditions where large irregular oscillations do not occur, boron injection produces the desired reduction in reactor power beneficial to overall failure-to-scram response. In addition, for failure-to-scram conditions in which large irregular oscillations occur after soluble boron begins to enter the core, continued boron injection provides a mitigating effect by reducing oscillation magnitude and duration until the reactor can no longer remain at power.

Neutron flux oscillations may be detected with greatest accuracy by monitoring local neutron flux instrumentation (e.g., Local Power Range Monitors (LPRMs), Intermediate Range Monitors (IRMs), and Source Range Monitors (SRMs)). Local neutron flux instrumentation is sensitive to regional as well as core-wide oscillations. With the exception of the quadrant-based APRMs utilized by some plants (e.g., NMP1), APRMs are less sensitive to regional oscillations because of the APRM averaging circuitry and the core wide radial and axial distribution of the LPRM inputs. However, even though LPRM signal cancellation occurs in the makeup of APRM signals, the cancellation is not perfect due to the phase-lag of oscillations in the axial direction. Analysis has shown that APRM peak-to-peak amplitudes reach 25% of rated thermal power well before any individual LPRM signal reaches an amplitude for which fuel damage might be possible.

Plants such as NMP2 equipped with an Oscillation Power Range Monitor which monitors LPRM signals can use that system as well to determine when the criterion specified in this step is satisfied. A thermal power calculation and alternate means of determining reactor thermal power (e.g., number of open SRVs or main turbine bypass valves, etc.) are not sufficient to assess the decision in this step because reactor core instabilities do not significantly change average thermal power.

In the absence of large irregular oscillations induced by neutronic/thermal-hydraulic instabilities, fuel integrity and RPV integrity are not directly challenged even under failure-to-scram conditions as long as the core remains submerged (the preferred method of core cooling). A scram failure coupled with MSIV isolation, however, results in rapid heatup of the suppression pool due to the steam discharged from the RPV via SRVs. The resulting containment challenge thus defines the second of the two conditions requiring boron injection in this step.

If suppression pool temperature and RPV pressure cannot be maintained below the Heat Capacity Temperature Limit, an RPV Blowdown will be required. To avoid depressurizing the RPV with the reactor at power, it is desirable to shut down the reactor prior to reaching the Heat Capacity Temperature Limit. The Boron Injection Initiation Temperature is defined so as to achieve this goal when practicable.

The Boron Injection Initiation Temperature (BIIT) is the greater of:

- The highest suppression pool temperature at which initiation of boron injection will permit injection of the Hot Shutdown Boron Weight of boron before suppression pool temperature exceeds the Heat Capacity Temperature Limit. The Hot Shutdown Boron Weight is an amount of born sufficient to maintain the reactor shutdown on boron alone under hot plant conditions.

- The suppression pool temperature at which a reactor scram is required by NMP2 Technical Specifications (llO°F).

The BIIT is a function of reactor power. If boron injection is initiated before suppression pool temperature reaches the BIIT, an RPV Blowdown may be precluded at lower reactor power levels. At higher reactor power levels, however, the suppression pool heatup rate may become so high that the Hot Shutdown Boron Weight of boron cannot be injected before suppression pool temperature reaches the Heat Capacity Temperature Limit even if boron injection is initiated early in the event. To simplify the evaluation of the need for boron injection, the NMP-2 EOP-C5 replaces the BIIT curve with the limiting suppression pool value of 110°F.

Since failure-to-scram conditions may present severe plant safety consequences, the requirement to initiate boron injection is independent of any anticipated success of control rod insertion. When attempts to insert control rods satisfactorily achieve reactor shutdown, the requirement for boron injection no longer exists.

Only those actions directly impacting or intended to mitigate thermal-hydraulic stability have been selected for discussion in the response to this RAI. Other actions may indirectly impact thermal-hydraulic stability, but will be mitigated by the actions discussed above.

RAI E9

The NMP2 EOPs quote a 25 degree Fahrenheit (°F) value for the increase in suppression pool temperature during a reactor pressure vessel ATWS blowdown. Provide the bases for this 25 °F value.

NMPNS Response RAI E9

The pool temperature increase due to depressurization is related to the vessel inventory and initial suppression pool inventory. *[[*

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It should be noted that the 25 degree Fahrenheit (°F) value for the increase in suppression pool temperature during a reactor pressure vessel ATWS blowdown is not a quote from the NMP2 EOPs. This information was presented to the NRC ATWS / Long–term Stability Audit team during the EOP portion of the audit presentation, on October 28, 2009.

RAI E10

Describe any effects or impacts, if any, of the proposed EPU on suppression pool cooling, EOPs, or ECCS (NPSH) requirements.

NMPNS Response RAI E10

The response to this RAI is limited to a discussion of the impacts during an ATWS event.

The action time for placing suppression pool cooling in service is unchanged from CLTP to EPU conditions. Suppression pool cooling is assumed to be in service at 1080 seconds into the event. Peak suppression pool temperature increases from 155°F at CLTP to 163°F at EPU conditions. If an RPV blowdown is required during the ATWS event, then the suppression pool temperature will increase an additional 25°F making the maximum suppression pool temperature 188°F. Suppression pool temperature used for RHR and HPCS Net Positive Suction Head (NPSH) calculations is 212°F with no containment overpressure credit. Therefore, ECCS NPSH requirements are not adversely affected.

There are no new credited operator actions required as a result of EPU. The analysis for EPU credits existing manual actions following the same time limits currently credited for the CLTP limit for the ATWS transient. The higher power level and increased decay heat associated with EPU have the following impact on EOP parameters:

- Heat Capacity Temperature Limit - The EPU will result in additional heat being added to the suppression pool during certain accident scenarios. The Heat Capacity Temperature Limit (HCTL) curve will be revised as a result of the increase in decay heat rejected to the suppression pool. The change is not significant.

- Cold Shutdown Boron Weight - The Cold Shutdown Boron Weight will be revised as a result of the increase in equilibrium core design for EPU by ~ 18%. The Hot Shutdown Boron Weight is expected to be impacted by an equivalent amount. Upon cycle specific analysis these values will be confirmed. The technical specification value does not change as it is conservative to the values used in the EOPs.

The changes to these parameters reflect the change in power level, but will not be adjusted in a manner that involves a change in accident mitigation strategy.

RAI E11

Please provide a short description of the simulator neutronic core model.

NMPNS Response RAI E11

The neutronic core model for the training simulator is (Studsvik's) Simulate-3R, a real time version of the Simulate-3. The installed core is updated at beginning of each new operating cycle to "match" the core design for that cycle. Exposure updates (wrap-ups) are added during the operating cycle so that the Simulator's nuclear core exposure and performance is consistent with the actual core performance at that point in time in the operating cycle. On the basis of accuracy and margin to real-time, the (Studsvik's) Simulate-3R (S3R) in the Simulator is configured to run in one radial node per assembly and 16 axial core levels. The Simulate-3 code uses four radial nodes per assembly and 25 axial core levels for depletion analysis and core design. Simulate-3 is used to extract the data in its original form at a given exposure point, and subsequently to collapse it to the specified nodalization for the S3R model in the Simulator. It should be noted that S3R does not use albedos to model the core boundary conditions, but rather models reflector nodes directly. Therefore, 18 (16+2) axial levels are computed and a lateral node is added to each face in the x-y plane.

RAI E12

During an October 28, 2009, staff audit, the NRC staff observed a series of ATWS scenarios in the NMP2 training simulator. The EPU power ATWS scenario was limited because the simulator had not been fully programmed for these conditions. When the NMP2 simulator is upgraded for EPU conditions, provide results of an MSIV isolation ATWS scenario at both CLTP and EPU conditions to compare the impact of EPU conditions.

NMPNS Response RAI E12

The NMP2 simulator will be modified for EPU changes prior to the 2012 startup tests for the increased power level. The simulator will be modified to maintain the required fidelity in accordance with site procedures and ANSI/ANS 3.5 - 1998. The simulator changes will include hardware changes for new and modified instrumentation and controls, software updates for modeling EPU changes and re-tuning of the core physics model for cycle specific data. When the NMP2 simulator is upgraded for EPU conditions, the MSIV isolation ATWS scenario at EPU conditions will be run as part of project implementation and a comparison of the results of this scenario with a similar CLTP scenario will be made available for review.

RAI E13

Provide a list of approved methodologies used to support the calculation for Section 2.8.3 of the proposed EPU LAR.

NMPNS Response RAI E13

The list of methodologies used for Section 2.8.3 are as follows:

1. ISCOR Version 9 – The ISCOR code is not approved by name. However, the SER supporting approval of NEDE-24011P Rev. 0 by the May 12, 1978 letter from D. G. Eisenhut (NRC) to R. Gridley (GE) finds the models and methods acceptable, and refers to the use of a digital computer code. The referenced digital computer code is ISCOR. Therefore, ISCOR is acceptable to provide core thermal-hydraulic information in reactor internal pressure differences, Transient, ATWS, Stability, and LOCA applications.

2. PANACEA Version 11 – The PANCEA Methodology was approved per NEDE-30130-P-A. The use of PANACEA Version 11 was initiated following approval of Amendment 26 of GESTAR II by letter from S.A. Richards (NRC) to G.A. Watford (GE) Subject: "Amendment 26 to GE Licensing Topical Report NEDE-24011-P-A, GESTAR II Implementing Improved GE Steady-State Methods," (TAC NO. MA6481), November 10, 1999.

3. ODYSY Version 5 – NRC Approval per Reference E13-1.

4. OPRM Version 1 - The methodology as implemented in the OPRM code has been approved per Reference E13-2.

5. TRACG Version 4 - TRACG02 has been approved in Reference E13-2 by the NRC for the stability DIVOM analysis. The CLTP stability analysis is based on TRACG04, which has been shown to provide essentially the same or more conservative results in DIVOM applications as the previous version, TRACG02.

References:

E13-1. ODYSY Application for Stability Licensing Calculations, NEDC-32992P-A, July 2001.

E13-2. Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications, NEDO-32465-A, August 1996.

Health Physics and Human Performance

RAI F1

In Section 2.11.1.1 (page 2-373) of NEDO-33351, "Safety Analysis Report for Nine Mile Point Nuclear Station Unit 2 Constant Pressure Power Uprate (PUSAR) (non-proprietary version)," it is stated that the abnormal operating procedure for feedwater failure, N2-SOP-6, be changed such that the reactor recirculation runback logic will be modified to initiate the runback immediately upon a feedwater pump trip. What does this mean to the operator and the associated times available and time required for the operator to complete the actions required in this procedure?

NMPNS Response RAI F1

The purpose of the modification to the reactor recirculation runback logic is to immediately initiate a power reduction using a reduction in reactor recirculation flow, upon a feedwater pump trip when operating above the capacity of a single feedwater pump. The runback logic will increase the runback rate of the flow control valves from 6 to 8%/sec to 9%/sec. The current reactor recirculation runback logic initiates when in single feedwater pump operation and reactor vessel water level decreases to the low level alarm setpoint (level 4). The modification to the reactor recirculation runback logic will improve the scram avoidance margin during a single feedwater pump trip event.

The runback logic will initiate automatically requiring no operator action at the time of the feedwater system failure.

The modification to the reactor recirculation runback logic provides improved margin to the reactor vessel low low level scram setpoint (level 3) by including an anticipatory feature and not waiting for an actual reduction in reactor vessel level, before initiating a reactor recirculation runback. The modification also prevents unnecessary runbacks form occurring if the triggering event occurs at a power level within the capacity of single feedwater pump.

The changes discussed above will provide additional time for the operator to take manual actions for power reduction to remain within single feedwater pump operating limits. N2-SOP-6 will not require any manual operator actions to implement or support the runback logic changes.

When the changes to the runback logic are implemented, analysis demonstrates that the reactor water level response remains above the low low level 3 setpoint without operator action. Minimum reactor water level occurs approximately 13 seconds from the start of the transient.

RAI F2

In Section 2.11.1.1 (page 2-373) of NEDO-33351 PUSAR, it is stated that the Loss of Condenser Vacuum abnormal operating procedure, N2-SOP-9, will be revised such that the Turbine Back Pressure Alarm Limit for EPU full power operation will be slightly less restrictive and will be incorporated in the Loss of Vacuum SOP. The alarm set point will be changed to allow operation closer to the trip set point. What is the margin between the new alarm setpoint proposed under EPU conditions and the trip setpoint under EPU conditions? What, if any, is the impact on the operator's ability to complete the necessary actions before the trip setpoint?

NMPNS Response RAI F2

Under current conditions, the margin between the low vacuum alarm setting and the turbine back pressure trip setting is 2.5" Hg. At EPU conditions, this margin is reduced to 2.1" Hg.

The impact of the reduced margin on the operator's ability to complete the necessary actions before the trip setpoint is dependent upon the cause of the loss of vacuum and the resulting rate of change in back pressure. The primary operator action in a degraded condenser vacuum condition is to lower power to stabilize vacuum. If this action is unsuccessful, the operator is directed to trip the turbine prior to reaching the low vacuum turbine trip setpoint of 22.1" Hg. This action, by design, will have the operator scram the reactor before tripping the turbine if reactor power is above the bypass capability of the turbine bypass valves. If the rate of vacuum decay is fast enough to preclude the operator from reducing power to stabilize vacuum, the operator has the option to scram the reactor by placing the reactor mode switch to shutdown prior to the turbine trip.

N2-SOP-09 is structured so that as time permits, the operator may perform certain mitigating actions, as described above, to stabilize the plant and to perform manual actions before automatic actions occur. Reduced operating margins caused by either a reduction in the margin between the alarm and trip settings or faster rates of vacuum decay have the same net effect on the operator's ability to stabilize vacuum before automatic actions occur. For a gradual loss of vacuum there is minimal impact on the operator's ability to complete the necessary actions before the trip setpoint.

RAI F3

In Section 2.11.1.1 (page 2-373) of NEDO-33351 PUSAR, it is stated that the Main Condenser Tube Rupture / Condensate High Conductivity abnormal operating procedure, N2-SOP-10, has been revised. Steps were added to verify closure of the condensate demineralizer bypass valve installed as part of EPU modifications. Does this change mean that the current procedures have a step that requires the operator to verify the closure of the original bypass valves, and the change to this procedure for proposed EPU conditions will add a step for the operator to verify the state of the heater drain pump? Will the procedure be updated with a provision that states that if the heater drain pump is out of service, that instead of verifying closure of the original bypass valves, the operator should verify the EPU bypass valves are closed? In the aforementioned situation, would the operators be verifying that the original bypass valves are opened, so that the condensate pre-filters are not bypassed? Please clarify the changes to operator actions.

NMPNS Response RAI F3

The current revision of N2-SOP-10, Main Condenser Tube Rupture or Condensate High Conductivity, contains a step to verify closure of the original bypass valve. This valve bypasses both the iron pre-filters and the condensate demineralizers. The design basis for this valve is to open on turbine trip at high power so that sufficient feedwater pump suction pressure is available to avoid a feedwater pump low suction pressure trip. The procedure also has a step to verify closure of the additional bypass valve that was added to support EPU power level (EPU bypass valve). The additional bypass flow path only bypasses the condensate demineralizers. The basis for the additional valve is to provide sufficient suction pressure to the feedwater pumps when a heater drain pump is out of service. The EPU bypass valve is only expected to be open when operating at EPU conditions above 85% power with a heater drain pump out of service.

N2-SOP-10 will be revised prior to EPU implementation to verify the status of heater drain pump operation. If all three heater drain pumps are operating, then the EPU bypass valve will be verified closed. If a heater drain pump is out of service, then a power reduction to approximately 85% will have to be performed prior to closure of the EPU bypass valve. The originally installed bypass valve operation is unaffected by EPU and will be verified closed the same as the current revision of the procedure. The objective of N2-SOP-10 will remain the same, which is to eliminate condensate demineralizer bypass flow paths during periods of high conductivity in the condensate system. In this configuration, neither the condensate pre-filters nor the condensate demineralizers will be bypassed.

RAI F4

In Section 2.11.1.2 (pages 2-373 and 2-374) of NEDO-33351 PUSAR, it is stated that the Combustible Gas Control in Containment scenario assumes that the operators actuate containment sprays within 30 *minutes after the LOCA (UFSAR 6.2.5.1). It further states in this section that operators initiate the hydrogen recombiners in 32.6 hours. The hydrogen recombiner initiation time is reduced by 10.9 hours. CLTP initiation time is 43.5 hours. This time reduction is due to a change in the analyzed value of percent of hydrogen and oxygen concentrations in the containment at which the recombiner system is started following the accident. How many other actions are the operators expected to complete during this time span which has been reduced by 10 hours. Was this time change analyzed with regards to the ability of operators to complete the necessary actions? Was there a validation process associated with this time change? Is it assumed that the operators will initiate core spray and initiate the hydrogen combiners in the same sequence of actions?*

NMPNS Response RAI F4

Although the time from the beginning of a LOCA until the hydrogen recombiner is required to start to prevent a flammable hydrogen/oxygen mixture has been reduced with respect to the implementation of EPU, the time is considerably more than the accepted minimum time for operator action specified in Constant Pressure Power Uprate License Topical Report – NEDC-33004P-A, Revision 4, Class III, July 2003. The need for an earlier start of the system after the accident does not affect the ability of operators to respond to the event, because the system is typically started hours or days following the event. This has not been evaluated relative to operator actions other than recombiner start that might be taken during the accident coping period because the time margin is above [[ ]].

The recombiner warm-up time is very small (1.5 hours) and recombiner start time is on the order of 0.5 hour. Thus, the overall recombiner start time is very small compared to the required start time of 32.6 hours after LOCA. Therefore, acceptability of the reduction in the recombiner start time (from 43.5 to 32.6 hours) was not validated.

The core sprays initiation is not tied to recombiner initiation sequence in EOPs.

RAI F5

In Section 2.11.1.2 (2-374) of NEDO-33351 PUSAR, it is stated that the EOPs are symptom-based procedures. These procedures, as written, do not have specific time constraints, or time limits associated with their execution. EPU conditions will result in greater decay heat loads. The actual EOP actions performed by operators are not changed. Those actions that remove decay heat will be influenced. Have these actions been identified, and how will they be influenced by the proposed EPU conditions? It is also stated in this section that the NMP2 simulator will be modified for EPU changes. Will these modifications occur prior to implementation? Have the changes been identified? This section of NEDO-33351 PUSAR also states decay heat changes and their effects on EOP execution have been reviewed, and appropriate training will be provided to the operators. UFSAR action times that would be executed under the guidance of EOPs are included in the evaluation of this section. Does this evaluation of UFSAR action times refer to the entire list of changes to operator actions sensitive to power uprate or is this a reference to an evaluation located in the UFSAR. Please clarify.

NMPNS Response RAI F5

Operator actions contained in the Emergency Operating Procedures (EOPs) that are impacted by greater decay heat loads have been identified. There were no new credited operator actions required as a result of the EPU.

Several operator actions are evaluated in the license basis for NMP2. The plant documents containing a discussion of operator actions include the Updated Safety Analysis Report (USAR), supporting engineering analysis and calculations and the Technical Specifications. The analysis for EPU credits existing manual actions following the same time limits currently credited for the CLTP limit except as noted below.

- Combustible Gas Control in Containment assumes the following operator actions. Operators actuate containment sprays within 30 minutes after the LOCA. For EPU conditions, operators are assumed to initiate the hydrogen recombiners within 32.6 hours. The hydrogen recombiner initiation time is reduced by 10.9 hours from the CLTP initiation time of 43.5 hours. This time reduction is due to a change in the analyzed value of percent of hydrogen and oxygen concentrations in the containment at which the recombiner system is started following the accident. For CLTP, the system initiation gas concentration values are 4% hydrogen and 4.5% oxygen. For EPU, the system initiation gas concentration values are 3.4% hydrogen and 3.6% oxygen. Because of this change in gas concentration values at which the system is initiated, a direct comparison of the CLTP and post-EPU results is not considered relevant. Additionally, the CLTP time analysis is based on a six hour warm up time for the recombiner versus an actual warm up time of 1.5 hours. Since the warm up time is included in the initiation time, the impact on operator action time reduction of 10.9 hours is reduced by4.5 hours to 6.4 hours.

- The Anticipated Transient without Scram (ATWS) analysis assumes 1080 seconds to initiate Residual Heat Removal Suppression Pool Cooling. These times do not change for EPU. NMP2 plant-specific ATWS analysis takes credit for operator action to inhibit ADS. This does not change for EPU.

- The Long Term Design Basis Loss of Coolant Accident (DBA-LOCA) assumes operators initiate containment cooling 30 minutes from initiation of the event. This time does not change for EPU.

- Containment cooling is assumed to be initiated in 20 minutes for Steam Bypass conditions. This is a reduction of ten minutes from CLTP conditions for this event. However, the current licensing basis for the initiation of containment sprays for similar events provided in USAR 6.2.1.1.3, Design Evaluation - Assumptions for Long-Term Cooling, and in the Alternative Radiological Source Term Safety Evaluation (PUSAR Reference 34) is 20 minutes. For this reason, this time reduction has no impact on actual operator response time.

- Drywell sprays, supplied by the RHR pumps, are assumed to be manually initiated in 20 minutes following the initiation of the DBA-LOCA.

- For applicable cases other than DBA-LOCA, results demonstrate that manual actuation of Drywell spray within 30 minutes after the break will limit containment peak pressure to less than the design value.

- Station blackout (SBO) actions are initiated to establish reactor water level control and reactor pressure control within two minutes into the event. This time does not change for EPU. Other 15, 30, 60 and 120 minute action times to defeat Reactor Core Isolation Cooling (RCIC) trips, reduce control room heat loads, reduce RCIC room heat load and reduce DC battery loads remain unchanged for EPU as well. The Heat Capacity Temperature Limit (HCTL) curve for SBO changes, but the change is not significant (~ 1 degree).

- There is no change in action time and no new required actions for Control Room Evacuation. The CLTP action time to initiate a blow down from the remote shutdown panel is within 10 minutes. Operators have demonstrated that the actions for the control room evacuation can be performed within 10 minutes. The analysis was revised for EPU and takes credit for a peak fuel clad temperature of less than 1500°F instead of requiring Reactor Pressure Vessel water level to remain above Top of Active Fuel (TAF). With the change in acceptance criteria, the operator action time to initiate a depressurization from the remote shutdown panel could be increased from 10 minutes to 13.4 minutes. The containment temperature analysis was performed with an operator action time of 10 minutes and increasing this time to 13.4 minutes is conservative for the containment analysis. For the containment, operator action after 10 minutes is allowed, however the early blow down at 10 minutes represents a more limiting case. The EPU operator action time credited in the analysis will remain at 10 minutes since operators have demonstrated that this performance criterion can be satisfied. The change in acceptance criteria demonstrates adequate margin to respond to this event effectively at EPU conditions.

- The RHR shutdown cooling mode is assumed to be unavailable following all transients. Operator action is assumed to establish alternate shutdown cooling one hour after the reactor pressure permissive of 150 psia is reached. This time does not change for EPU.

- Instrument Line Break into Secondary Containment assumes operators commence a reactor cool down in 30 minutes. This time does not change for EPU.

- Time to Boil – The time interval from loss of fuel pool cooling to fuel pool boiling (time to boil) is decreased under EPU conditions. For the limiting full core offload case, the time to boil is decreased from approximately 5.5 hours to approximately 5.1 hours. For normal operation, the Spent Fuel Pool Cooling system is assumed to be realigned in 3 hours, and for station blackout the coping time is 4 hours. Therefore, there are no changes from CLTP to EPU.

- Credit is taken for operator action to isolate a leak within 30 minutes of detection to mitigate flooding of an area in the plant. For flooding in the main steam tunnel, operator action is required as soon as possible and within 100 minutes. This time does not change for EPU.

- The Control Room Special Filter Train system design is such that both special filter trains automatically start simultaneously on a LOCA signal or supply air radiation monitor trip signal. Both fans will continue to run until manually secured. One of the two operating fans is required to be shutdown within 20 minutes of initiation on a valid LOCA/high radiation signal. This action is required to comply with engineering analysis of Control Room dose during accident conditions. The fan placed in standby will automatically start if the running fan trips. This time does not change for EPU.

- Operator action is credited to manually isolate reactor water cleanup system on a line break in the main steam tunnel in 1 hour to limit the release. This time does not change for EPU.

Modifications to the NMP2 simulator associated with EPU will be completed prior to implementation. Changes resulting from hardware modifications, analyses (changes in decay heat load, containment analysis, etc.) and setpoint changes not associated with specific hardware changes are identified and implemented during the design change process. The changes that have been identified that are associated with equipment modifications that will be installed during the 2010 refueling outage will be implemented prior to startup from the 2010 outage. Additional equipment modifications that will be installed during the 2012 refueling outage, as well as analytically derived changes not associated with equipment modification, will be identified and implemented by early 2012 so that operator training at EPU conditions may be conducted prior the outage preceding operation at EPU conditions.

Vessels & Internals Integrity

RAI G1

The submittal refers to BWRVIP-74 on pages 2-3 and in Table 2.1-3. Is BWRVIP-74 the proper reference or should it be referred to the SER for BWRVIP-05? Does NMP2 plan to submit an updated request for relief reflecting the data shown in Table 2.1-3, which will reflect the higher fluence at 54 EFPY for the EPU conditions? If so, please provide as a regulatory commitment.

NMPNS Response RAI G1

The submittal references the BWRVIP program primary document BWRVIP-74, which provides the requirements that must be satisfied for circumferential weld relief. BWRVIP-74 Section A.4.1 references the NRC SER for BWRVIP-05 as the source. The conclusion is that the BWRVIP-74 is considered an acceptable reference source.

NMPNS provided the technical justification in the submittal for the acceptability of the circumferential weld relief for a conservative projected fluence. It is understood that fluence is impacted by fuel changes, operating strategy and power uprate and the NMP2 vessel integrity program uses the Regulatory Guide (RG) 1.190 fluence method and maintains the projections on a routine basis. The program will identify when the maximum fluence used for the relief request is anticipated to be exceeded and require submittal of an update to the relief request. The submittal provides justification that we anticipate no issues with EPU impacting the acceptability; but formal application for relief is based on projections of exceeding the fluence and not EFPY. It is understood that EFPY projections are not an accurate method of predicting fluence over large time frames with multiple changes such as fuel type and operating strategy. Therefore, no commitment is considered required and NMP2 is already committed to maintain a RG 1.190 fluence program.

RAI G2

Since the applicant stated that it is incorporating hydrogen water chemistry (HWC) and noble metal chemical addition (NMCA) programs, the staff requests the licensee to identify the method of controlling HWC/NMCA in the reactor vessel. Provide details on the methods for determining the effectiveness of HWC/NMCA by using the following parameters:

(a) electrochemical potential (ECP),
(b) feedwater hydrogen flow,
(c) main steam oxygen content, and
(d) hydrogen / oxygen molar ratio

NMPNS Response RAI G2

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

Online Noble Metal Application was implemented at NMP2 in 2007. This method has applications performed during power operations on an approximately annual frequency. The effectiveness monitoring is performed by process controls and platinum feed monitoring during On Line Noble Chemistry (OLNC) application supplemented with coupons. Note: NMP2 installed an ECP probe to monitor the OLNC application effectiveness. This ECP was used during the initial OLNC application to monitor the deposition and the effectiveness of the application. The ECP is not used as a method of controlling HWC/NMCA on a routine basis.

Supplemental Response to Round 1 RAI G3 from E-mail Dated January 12, 2010

Regarding the response to RAI G3, the last paragraph on page 29 of 31 in attachment 1 states:

"The combined margin of 73.6 psi is recognized to provide minimally sufficient margin for SLCS pump discharge valves, at both CLPT and EPU conditions. As such, the piping is being rerated and the relief valve set pressure increased to provide additional margin."

- *We'd like to understand how the margin of 73.6 psi was determined.*
- *Also, we'd like to know what the SLCS relief valve discharge pressure is being reset to and when this is going to be done.*

RAI G3

The Technical Evaluation in Section 2.8.4.5 states that there is 31.6 psi margin between the maximum reactor upper plenum and the standby liquid control system (SLCS) pump relief valve setpoint. This 31.6 psi margin includes a SLCS pump relief valve setpoint tolerance of 3%, but it appears that the margin does not include an overall combined accuracy of the instrumentation used to perform the SLCS pump relief valve setpoint test. Please explain how the overall combined accuracy of the instrumentation used to perform SLCS pump relief valve setpoint tests was accounted for when calculating the margin between the maximum reactor upper plenum and the SLCS pump relief valve setpoint.

NMPNS Response RAI G3 (Revised)

The SLCS pump relief valve setpoint maintains a 31.6 psi margin to relief valve lift, in addition to the 3% set pressure tolerance (42 psi). Therefore, the combined margin is 73.6 psi.

The overall combined accuracy of the test instrument is not accounted in the margin calculation. However, the instrument used for the set pressure determination meets the ASME OM CODE-2004, which is adopted in the NMP2 IST program. The gauge accuracy used in the set pressure determination is ±0.5% compared to the code requirement of ±1%.

The combined margin of 73.6 psi is recognized to provide minimally sufficient margin for SLCS pump relief valves, at both CLTP and EPU conditions. As such, the piping design pressure is being rerated and the relief valve set pressure increased to provide additional margin.

The margin of 73.6 psi was defined based on nominal relief valve setpoint of 1400 psi minus the pump discharge pressure of 1326.4 psi. This margin is 1 psi less than the existing margin that has been demonstrated effective at eliminating relief valve lift during surveillance testing. However, for the current operating condition the 75 psi margin to SLCS relief valve nominal setpoint has not prevented relief valve seat seepage during SLCS pump surveillance testing. To resolve this issue the SLCS relief valve vendor has recommended maintaining approximately a 10% margin between the maximum SLCS pump pressure pulsation and the nominal relief valve setpoint. To achieve this margin the SLCS piping and components are being rerated to 1600 psig. The setpoint for the relief valve will be established to include at least a 10% margin between the maximum SLCS pump peak pressure pulsation and the relief valve minimum setpoint, (1459 psi) or approximately a 133 psi margin. The rerating of the piping to 1600 psig will provide the ability to increase the relief setting to a maximum of 1600 psi providing approximately a 20% margin above the pump discharge pressure of 1326.4 psi.

This modification is currently planned for implementation during the spring 2010 refueling outage.

ATTACHMENT 1

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING LICENSE AMENDMENT REQUEST FOR EXTENDED POWER UPRATE OPERATION (NON-PROPRIETARY)

Revised Response to Round 1 RAI B1c from E-mail Dated January27, 2010

Delete statement "All welds included in this category are weld overlays" from NMPNS Response RAI B1c, as indicated below.

RAI B1c)

For all welds other than Category A welds, describe the augmented inspection programs and discuss their adequacy in light of the EPU.

NMPNS Response RAI B1c) (Revised)

NMPNS has implemented an augmented intergranular stress corrosion cracking (IGSCC) inspection program in accordance with Generic Letter 88-01, NUREG-0313, and as modified by BWRVIP-75 for IGSCC Category D weld examination frequency using normal water chemistry. NMPNS has implemented ASME Section XI, Appendix VIII for the performance demonstration for ultrasonic examination systems administrated through the Electric Power Research Institute (EPRI) PDI program. Appendix VIII provides the requirements for the performance demonstration for ultrasonic examination procedures, equipment, and personnel to detect and size flaws.

Provided below is a summary by IGSCC Category of the current augmented program. EPU does not change the temperature, pressure or chemistry of these process fluids. The assumptions of the GL 88-01 program remain bounding for the radiolytic conditions for EPU. Refer to the response to RAI B2 below for a discussion of hydrogen water chemistry (HWC).

IGSCC Category B and C Weldments

NMP2 has no Category B or C welds.

IGSCC Category D Weldments - Non-resistant materials; no stress improvement

IGSCC Category D welds are examined at a frequency of 100% of the population (47 welds) every six years. NMP2 is on a two-year refueling cycle, so the frequency is 100% every three refueling outages.

IGSCC Category E Weldments - ~~All welds included in this category are weld overlays~~

IGSCC Category E welds reinforced by weld overlay, a 25% sample is required every ten years. Fifty percent will be completed within the first 6 years of the interval.

IGSCC Category E welds mitigated by SI require a 100% sample every 6 years.

IGSCC Category F and G Weldments

NMP2 has no Category F or G welds.

Supplemented Response to Round 1 RAI D1 E-mail Dated February 1, 2010

For D1, the staff would like to understand the NMP2 application of the GE BWROG TR relative to the associated 10 CFR requirements. In other words, how is the criteria being changed in reference to the TR, and still meeting all associated requirements (e.g., 10 CFR 50 App R).

RAI D1

Attachment 11 to NEDC-33351P Revision 0, Section 2.5.1.4, "Fire Protection," states that "...Any changes in physical plant configuration or combustible loading as a result of modifications to implement the extended power uprate (EPU) will be evaluated in accordance with plant modification and fire protection programs..." Clarify whether this request involves plant modifications or physical changes to the fire protection program. If any, the staff requests the licensee to identify proposed modifications and discuss impact of these modifications on plant's compliance with fire protection program licensing basis, Title 10 of the Code of Federal Regulations (10 CFR) 50.48, or applicable portions of 10 CFR 50, Appendix R.

NMPNS Response RAI D1 (Revised)

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

In the event of a Control Room evacuation the Special Operating Procedure requires the disconnection of RCIC auto isolation and initiation signals from the control room prior to going to the Remote Shutdown Panel (RSP). At the RSP, RCIC is initiated and operated maintaining reactor water level above top of active fuel (TAF). If RCIC fails to operate as expected then the low pressure "pseudo" LPCI mode of the RHR system and the four SRVs are operated at the RSP to depressurize and inject water into the vessel. The 1500°F peak cladding temperature criteria in lieu of water level remaining TAF will apply when using the low pressure "pseudo" LPCI mode of the RHR system and the four SRVs.

RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION REGARDING LICENSE AMENDMENT REQUEST FOR EXTENDED POWER UPRATE OPERATION (NON-PROPRIETARY)

Revised Response to Round 1 RAI B2 Phone Conversation on February 11, 2010, (J. J. Dosa (NMPNS) and R Guzman (NRC))

The staff requested NMPNS provide a copy of BWRVIP-190 to support the review of Round 1 Piping & Non-Destructive Examination RAI B2. NMPNS is providing a revised response to RAI B2 deleting the reference to BWRVIP-190.

RAI B2:

Oxygen content in the coolant is expected to increase due to increased radiolysis of water resulting from the EPU. Since hydrogen water chemistry (HWC) is being employed, describe how the electrochemical potential measurements will be made to ensure that the hydrogen injection rate is adequate to maintain the effectiveness of HWC at the most limiting locations.

NMPNS Response RAI B2 (Revised)

Nine Mile Point Unit No. 2 (NMP2) does not use HWC alone for Intergranular Stress Corrosion Cracking (IGSCC) mitigation. NMP2 uses the On-line NobleChem™ (OLNC) process of noble metal chemical addition (NMCA) along with HWC injection for IGSCC mitigation of piping and reactor internals.

NMP2 is a BWRVIP-62 category 3b* which does not use electrochemical potential (ECP). The primary parameters monitored for mitigation are catalyst loading (with the Mitigation Monitoring System (MMS)) and the measured H_2:O_2 Molar Ratio (by means of reactor water chemical analysis).

At EPU conditions the 100% power hydrogen injection rate will be increased to the EPU predicted value of 17.6 scfm (presently 15 scfm). This will mitigate the increased oxygen generation due to the increased radiolysis at the power levels of EPU. The predicted injection rate is preliminary; therefore testing/monitoring under EPU conditions will be performed to obtain the final injection rate for mitigation at EPU.

After EPU implementation, NMP2 will continue to use our established IGSCC mitigation monitoring program to measure the H_2:O_2 Molar Ratio. The HWC hydrogen injection rate will be changed as needed after EPU implementation to assure that a molar ratio of three or more is maintained.

* BWRVIP letter 2001-250, August 1, 2001, Project No. 704 – BWRVIP response to NRC Safety Evaluation of BWRVIP-62, Table 3-5.

ATTACHMENT 2

REPLACEMENT PAGES FOR NEDO-33351, REVISION 0, SAFETY ANALYSIS REPORT FOR NINE MILE POINT NUCLEAR STATION UNIT 2 CONSTANT PRESSURE POWER UPRATE (LAR ATTACHMENT 3)

Information in this attachment is not considered proprietary.

Nine Mile Point Nuclear Station, LLC
February 19, 2010

Operators initiate the hydrogen recombiners in 32.6 hours. The hydrogen recombiner initiation time is reduced by 10.9 hours. CLTP initiation time is 43.5 hours. This time reduction is due to a change in the analyzed value of percent of hydrogen and oxygen concentrations in the containment at which the recombiner system is started following the accident. For CLTP, the system initiation gas concentration values are 4% hydrogen and 4.5% oxygen. (USAR 6.2.5.2.2) For EPU, the system initiation gas concentration values are 3.4% hydrogen and 3.6% oxygen. Because of this change in gas concentration value at which the system is initiated, a direct comparison of the CLTP and post EPU results is not considered relevant. Operating procedure system initiation values do not change for EPU, only the engineering evaluation is changed.

- The Anticipated Transient without Scram (ATWS) analysis assumes 1080 seconds to initiate Residual Heat Removal (RHR) Suppression Pool Cooling. These times do not change for EPU. NMP2 plant-specific ATWS analysis takes credit for operator action to inhibit ADS. This does not change for EPU.

- Long Term DBLOCA assumes operators initiate containment cooling 30 minutes from initiation of the event. This time does not change for EPU. (USAR Table 6.2-52) (Appendix 6C Humphrey Concerns)

- For Steam Bypass, containment cooling is initiated in 20 minutes. This is a reduction of ten minutes from CLTP conditions for this event. However, the current licensing basis for the initiation of containment sprays for similar events provided in USAR 6.2.1.1.3, Design Evaluation - Assumptions for Long-Term Cooling, and in the Alternative Radiological Source Term Safety Evaluation (Reference 34) is 20 minutes. For this reason, this time reduction has no impact on actual Operator response time.

- For the AST evaluation, containment cooling spray mode of RHR is initiated in 20 minutes. This time does not change for EPU.

- For a station blackout (SBO), actions to establish reactor water level control and reactor pressure control are initiated 2 minutes into the event. This time does not change for EPU. The other 15, 30, 60 and 120 minute action times to defeat RCIC trips, reduce control room heat loads, reduce RCIC room heat load and reduce DC battery loads remain unchanged for EPU as well. The HCTL curve for SBO changes but the change is not significant (~ 1 degree).

- For the Control Room Evacuation procedures, there is no change in action time and no new required actions. The CLTP action time to initiate a blow down from the remote shutdown panel is within 10 minutes. (USAR 9B.8.2.4) Operators have demonstrated that the actions for the control room evacuation can be performed within this time frame. The analysis was revised for EPU and takes credit for a peak fuel clad temperature of less than 1500 °F instead of requiring RPV water level to remain above TAF. With this change in acceptance criteria, the maximum operator action time to initiate a depressurization from the remote shutdown panel is 13.4 minutes. The containment temperature analysis was performed with a nominal operator action time of 10 minutes. The EPU operator action time credited in the analysis will remain at 10 minutes since operators have demonstrated that this performance criterion can be satisfied. The change in acceptance criteria demonstrates adequate margin to respond to this event effectively at EPU conditions.

- RHR shutdown cooling mode is assumed to be unavailable following all transients. Operator action is assumed to establish alternate shutdown cooling 1 hour after the reactor pressure permissive of 150 psia is reached. (USAR 6A.10.2.3.2 Power Uprate Analysis (1995 Stretch Uprate)). This time does not change for EPU conditions.

- Instrument Line Break into Secondary Containment assumes operators commence a reactor cool down in 30 minutes (NMP2 Calculation ES-114). This time does not change for EPU (USAR 15.6.2).

- The time interval from loss of fuel pool cooling to fuel pool boiling (time to boil) is decreased under EPU conditions. For the full core offload case, the time to boil is decreased from approximately 5.5 hours to approximately 5.1 hours. For normal operation, SFP system is assumed to be re-aligned in 3 hours (USAR 9.1.3), and for station blackout the coping time is 4 hours. Therefore there are no changes from CLTP to EPU.

- Credit is taken for Operator action to isolate a leak 30 minutes after detection to mitigate flooding of an area in the plant (USAR Appendix 3C Section 3C.5, Compartment Flooding as a Result of Breaks or Cracks). For flooding in the Main Steam Tunnel (MST) operator action is required as soon as possible and within 100 minutes. This does not change for EPU conditions.

- The Control Room Special Filter Train system design is such that both trains of HVC special filter trains will simultaneously autostart on a LOCA signal or supply air radiation monitor trip signal. Both fans will continue to run until manually secured. One of the two operating fans is required to be shutdown within 20 minutes of initiation on a valid LOCA/Hi radiation signal. This action is required to comply with Engineering analysis of Control Room dose during accident conditions. That fan once placed in standby will autostart if the running fan trips. (N2-OP-53A) This time does not change for EPU.

- ~~Operators ensure less contaminated outside air intake path is selected during a LOCA within 8 Hours (Increased MSIV Leakage Amendment) (N2-OP-53A) This time does not change for EPU.~~

- Operator action is credited to manual isolate reactor water clean up system on line break in the main steam tunnel in 1 hour to limit the release. This time does not change for EPU. (Calc S14-MST-A47-U2-37)

The Emergency Operating Procedures (EOPs) are symptom based procedures. They are used for a wide range of accidents and events that might challenge operators. These procedures, as written, do not have specific time constraints or time limits associated with their execution. They address plant symptoms/parameters independent of cause which allows for comprehensive actions to mitigate fuel damage and to prevent radioactive release. EPU conditions will result in

Table 2.13-7 Operator Action Evaluation

Basic Event	Description	MAAP Case (Table 2.13-4)	Pre-EPU		Post-EPU		HRA Methods
			Time	HEP	Time	HEP	
MSSZODMSSOP1OO01	Emergency Depressurization – Transient/SLOCA (1)	U2LOF1	40 Min	2.8E-4	35 Min	3.2E-4 (2)	(a)+(b)+(d)
ICSZMEECCSACTX01	Manual ECCS Actuation	U2LOF1	13 Min	0.1 (3)	11 Min	0.1 (3)	(a)+(b)+(d)
MSSZODMSSOP1OO02	Emergency Depressurization – MLOCA (1)	U2MLOCAW2	13 Min	1.8E-3	11 Min	2.1E-3 (2)	(a)+(b)+(d)
ENSZKROPERSWAP01	Crosstie 115kv After Partial Loss (5)	U2LOF1	40 Min	4.7E-2	35 Min	5.4E-2 (2)	(a)+(b)+(d)
HRAZHRBOPSRICS02	Recover From Fire in Control Room (6)	U2LOF1	40 Min	2.0E-3	35 Min	2.3E-3 (2)	(a)+(b)+(d)
HRAZHRBOPSRICF03	Recover From Fire in Control Room at RSP (6)	U2LOF1	40 Min	1.2E-2	35 Min	4.4E-2	(a)+(b)+(d)
FWSZFWXXXXXXXX01	Restore Feedwater – ATWS (7)	U2AT3	2.5 Min	0.41	2.5 Min	0.41 (4)	(c)+(d)
RPSZCHXXXXXXXX01	Control Level & Power – ATWS	U2AT3	6 Min	3.3E-2	6 Min	3.3E-2 (4)	(a)+(b)+(d)
DERZISXXXXXXXX01	Fail to Isolate Containment – Level 2 LERF	U2LOF1	50 Min	8.2E-2	45 Min	8.4E-2	(a)+(b)+(d)
RPSZCHXXXXXXXX02	ATWS, Restart HPCS	(12)	(12)	1.0	(12)	1.0	(e)
GSNZN2HHN23XXX03	Instrument Nitrogen, Align valve bypass	(9)	3 Hrs	0.1	(8)	0.1	(e)
ZKRZKROPACTKR303	Crosstie 115 Kv	U2LOF1	40 Min	1E-2	(8)	1E-2	(a)+(b)+(d)
NNSZOBOPACTOBX01	Align swing bus	U2LOF1	40 Min	0.1	(8)	0.1	(e)
RTXZNROPACTNRX01	Cross-tie 115Kv to NSR bus	U2LOF1	40 Min	0.1	(8)	0.1	(e)
ZOVZOVOPRECVSF01	Initiate containment sprays	(10)	10 Min	4.0E-2	(8)	4.0E-2	(a)+(c)+(d)
MSSZAIOPACT1OO01	AI - ATWS, RCIC success, Inhibit ADS	IPE HRA	3 Min	5.6E-3	(8)	5.6E-3	(a)+(c)+(d)
MSSZAIOPACT2OO02	AI - ATWS, RCIC unavailable, Inhibit ADS	IPE HRA	3 Min	5.6E-3	(8)	5.6E-3	(a)+(c)+(d)
MSSZODMSSOP1OO05	OD - ATWS, loss of high pressure injection. Manually emergency depressurize	IPE HRA	5 Min	0.16	(8)	0.16	(a)+(c)+(d)
ICSZOAXHHOA01X01	Bypass RCIC isolations (15 minutes)	(11)	15 Min	3.3E-3	(8)	3.3E-3	(a)
CNSZCRDOPERATOR1	Operator Fails to Align Standby CRD Train	(12)	(12)	1.0	(12)	1.0	(e)

Table 2.13-7 Operator Action Evaluation (Cont)

Notes:

(1) Timing is conservatively based on no high pressure injection makeup at start of event.
(2) This post EPU HEP was identical to the pre EPU HEP as the action was required in the same discrete time step. The post EPU HEP was increased by 15% to evaluate the sensitivity of reducing the time within that time step.
(3) This HEP is less than 1E-2 for both pre and post EPU. The 0.1 value has been used in the baseline PRA because of equipment dependencies where auto actuation failure may be non-recoverable. Since this is not affected by EPU there is no change in risk.
(4) There was no change in HEP thus no change in risk
(5) Top event KR split fractions were calculated and used to update master frequency files
(6) Several scenarios and system dependencies are affected, but the timing is conservatively based on loss of high pressure injection.
(7) Time to Level 1 is used as restoring feedwater before Level 1 allows operators to bypass MSIV Level 1 trip (not presently credited in the PRA) if this action is successful. Note that time to -39 inches (blow down required) could be used given present model.
(8) Not modified for Post-EPU, Pre-EPU (Baseline PRA) value applies.
(9) The time allowed is based primarily on bleed-off rates as well as the functional requirements of the system per U2 HRA Notebook.
(10) New MAAP Case post-EPU provides bases for 10 minutes. 4.0E-2 is conservative, new post-EPU value is 3.4E-2.
(11) Special Operating Procedure.
(12) This HEP is not credited.

Key to HRA Methods:

(a) EPRI CBDTM (Parry, G. W., An Approach to the Analysis of Operator Actions in Probabilistic Risk Assessment, EPRI TR-100259, June 1992)
(b) HCR/ORE (Spurgin, A.J., et al., A Human Reliability Analysis Approach Using Measurements For Individual Plant Examination, NP-6560-L, December 1989)
(c) ASEP (Swain, A.D., Accident Sequence Evaluation Program Human Reliability Analysis Procedure, NUREG/CR-4772, SAND86- 1996, February 1987)
(d) THERP (Swain, A.D., Guttmann, H.E., Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Applications, NUREG/CR-1278, August 1983)
(e) Screening Value

ATTACHMENT 3

REPLACEMENT PAGES FOR NEDC-33351P, REVISION 0, SAFETY ANALYSIS REPORT FOR NINE MILE POINT NUCLEAR STATION UNIT 2 CONSTANT PRESSURE POWER UPRATE (LAR ATTACHMENT 11)

Information in this attachment is not considered proprietary.

Nine Mile Point Nuclear Station, LLC
February 19, 2010

Operators initiate the hydrogen recombiners in 32.6 hours. The hydrogen recombiner initiation time is reduced by 10.9 hours. CLTP initiation time is 43.5 hours. This time reduction is due to a change in the analyzed value of percent of hydrogen and oxygen concentrations in the containment at which the recombiner system is started following the accident. For CLTP, the system initiation gas concentration values are 4% hydrogen and 4.5% oxygen. (USAR 6.2.5.2.2) For EPU, the system initiation gas concentration values are 3.4% hydrogen and 3.6% oxygen. Because of this change in gas concentration value at which the system is initiated, a direct comparison of the CLTP and post EPU results is not considered relevant. Operating procedure system initiation values do not change for EPU, only the engineering evaluation is changed.

- The Anticipated Transient without Scram (ATWS) analysis assumes 1080 seconds to initiate Residual Heat Removal (RHR) Suppression Pool Cooling. These times do not change for EPU. NMP2 plant-specific ATWS analysis takes credit for operator action to inhibit ADS. This does not change for EPU.
- Long Term DBLOCA assumes operators initiate containment cooling 30 minutes from initiation of the event. This time does not change for EPU. (USAR Table 6.2-52) (Appendix 6C Humphrey Concerns)
- For Steam Bypass, containment cooling is initiated in 20 minutes. This is a reduction of ten minutes from CLTP conditions for this event. However, the current licensing basis for the initiation of containment sprays for similar events provided in USAR 6.2.1.1.3, Design Evaluation - Assumptions for Long-Term Cooling, and in the Alternative Radiological Source Term Safety Evaluation (Reference 34) is 20 minutes. For this reason, this time reduction has no impact on actual Operator response time.
- For the AST evaluation, containment cooling spray mode of RHR is initiated in 20 minutes. This time does not change for EPU.
- For a station blackout (SBO), actions to establish reactor water level control and reactor pressure control are initiated 2 minutes into the event. This time does not change for EPU. The other 15, 30, 60 and 120 minute action times to defeat RCIC trips, reduce control room heat loads, reduce RCIC room heat load and reduce DC battery loads remain unchanged for EPU as well. The HCTL curve for SBO changes but the change is not significant (~ 1 degree).
- For the Control Room Evacuation procedures, there is no change in action time and no new required actions. The CLTP action time to initiate a blow down from the remote shutdown panel is within 10 minutes. (USAR 9B.8.2.4) Operators have demonstrated that the actions for the control room evacuation can be performed within this time frame. The analysis was revised for EPU and takes credit for a peak fuel clad temperature of less than 1500 ^{o}F instead of requiring RPV water level to remain above TAF. With this change in acceptance criteria, the maximum operator action time to initiate a depressurization from the remote shutdown panel is 13.4 minutes. The containment temperature analysis was performed with a nominal operator action time of 10 minutes. The EPU operator action time credited

in the analysis will remain at 10 minutes since operators have demonstrated that this performance criterion can be satisfied. The change in acceptance criteria demonstrates adequate margin to respond to this event effectively at EPU conditions.

- RHR shutdown cooling mode is assumed to be unavailable following all transients. Operator action is assumed to establish alternate shutdown cooling 1 hour after the reactor pressure permissive of 150 psia is reached. (USAR 6A.10.2.3.2 Power Uprate Analysis (1995 Stretch Uprate)). This time does not change for EPU conditions.

- Instrument Line Break into Secondary Containment assumes operators commence a reactor cool down in 30 minutes (NMP2 Calculation ES-114). This time does not change for EPU (USAR 15.6.2).

- The time interval from loss of fuel pool cooling to fuel pool boiling (time to boil) is decreased under EPU conditions. For the full core offload case, the time to boil is decreased from approximately 5.5 hours to approximately 5.1 hours. For normal operation, SFP system is assumed to be re-aligned in 3 hours (USAR 9.1.3), and for station blackout the coping time is 4 hours. Therefore there are no changes from CLTP to EPU.

- Credit is taken for Operator action to isolate a leak 30 minutes after detection to mitigate flooding of an area in the plant (USAR Appendix 3C Section 3C.5, Compartment Flooding as a Result of Breaks or Cracks). For flooding in the Main Steam Tunnel (MST) operator action is required as soon as possible and within 100 minutes. This does not change for EPU conditions.

- The Control Room Special Filter Train system design is such that both trains of HVC special filter trains will simultaneously autostart on a LOCA signal or supply air radiation monitor trip signal. Both fans will continue to run until manually secured. One of the two operating fans is required to be shutdown within 20 minutes of initiation on a valid LOCA/Hi radiation signal. This action is required to comply with Engineering analysis of Control Room dose during accident conditions. That fan once placed in standby will autostart if the running fan trips. (N2-OP-53A) This time does not change for EPU.

- ~~Operators ensure less contaminated outside air intake path is selected during a LOCA within 8 Hours (Increased MSIV Leakage Amendment) (N2-OP-53A) This time does not change for EPU.~~

- Operator action is credited to manual isolate reactor water clean up system on line break in the main steam tunnel in 1 hour to limit the release. This time does not change for EPU. (Calc S14-MST-A47-U2-37)

The Emergency Operating Procedures (EOPs) are symptom based procedures. They are used for a wide range of accidents and events that might challenge operators. These procedures, as written, do not have specific time constraints or time limits associated with their execution. They address plant symptoms/parameters independent of cause which allows for comprehensive actions to mitigate fuel damage and to prevent radioactive release. EPU conditions will result in

Table 2.13-7 Operator Action Evaluation

Basic Event	Description	MAAP Case (Table 2.13-4)	Pre-EPU		Post-EPU		HRA Methods
			Time	HEP	Time	HEP	
MSSZODMSSOP1OO01	Emergency Depressurization – Transient/SLOCA (1)	U2LOF1	40 Min	2.8E-4	35 Min	3.2E-4 (2)	(a)+(b)+(d)
ICSZMEECCSACTX01	Manual ECCS Actuation	U2LOF1	13 Min	0.1 (3)	11 Min	0.1 (3)	(a)+(b)+(d)
MSSZODMSSOP1OO02	Emergency Depressurization – MLOCA (1)	U2MLOCAW2	13 Min	1.8E-3	11 Min	2.1E-3 (2)	(a)+(b)+(d)
ENSZKROPERSWAP01	Crosstie 115kv After Partial Loss (5)	U2LOF1	40 Min	4.7E-2	35 Min	5.4E-2 (2)	(a)+(b)+(d)
HRAZHRBOPSRICS02	Recover From Fire in Control Room (6)	U2LOF1	40 Min	2.0E-3	35 Min	2.3E-3 (2)	(a)+(b)+(d)
HRAZHRBOPSRICF03	Recover From Fire in Control Room at RSP (6)	U2LOF1	40 Min	1.2E-2	35 Min	4.4E-2	(a)+(b)+(d)
FWSZFWXXXXXXXX01	Restore Feedwater – ATWS (7)	U2AT3	2.5 Min	0.41	2.5 Min	0.41 (4)	(c)+(d)
RPSZCHXXXXXXXX01	Control Level & Power – ATWS	U2AT3	6 Min	3.3E-2	6 Min	3.3E-2 (4)	(a)+(b)+(d)
DERZISXXXXXXXX01	Fail to Isolate Containment – Level 2 LERF	U2LOF1	50 Min	8.2E-2	45 Min	8.4E-2	(a)+(b)+(d)
RPSZCHXXXXXXXX02	ATWS, Restart HPCS	(12)	(12)	1.0	(12)	1.0	(e)
GSNZN2HHN23XXX03	Instrument Nitrogen, Align valve bypass	(9)	3 Hrs	0.1	(8)	0.1	(e)
ZKRZKROPACTKR303	Crosstie 115 Kv	U2LOF1	40 Min	1E-2	(8)	1E-2	(a)+(b)+(d)
NNSZOBOPACTOBX01	Align swing bus	U2LOF1	40 Min	0.1	(8)	0.1	(e)
RTXZNROPACTNRX01	Cross-tie 115Kv to NSR bus	U2LOF1	40 Min	0.1	(8)	0.1	(e)
ZOVZOVOPRECVSF01	Initiate containment sprays	(10)	10 Min	4.0E-2	(8)	4.0E-2	(a)+(c)+(d)
MSSZAIOPACT1OO01	AI - ATWS, RCIC success, Inhibit ADS	IPE HRA	3 Min	5.6E-3	(8)	5.6E-3	(a)+(c)+(d)
MSSZAIOPACT2OO02	AI - ATWS, RCIC unavailable, Inhibit ADS	IPE HRA	3 Min	5.6E-3	(8)	5.6E-3	(a)+(c)+(d)
MSSZODMSSOP1OO05	OD - ATWS, loss of high pressure injection. Manually emergency depressurize	IPE HRA	5 Min	0.16	(8)	0.16	(a)+(c)+(d)
ICSZOAXHHOA01X01	Bypass RCIC isolations (15 minutes)	(11)	15 Min	3.3E-3	(8)	3.3E-3	(a)
CNSZCRDOPERATOR1	Operator Fails to Align Standby CRD Train	(12)	(12)	1.0	(12)	1.0	(e)

Table 2.13-7 Operator Action Evaluation (Cont)

Notes:

(1) Timing is conservatively based on no high pressure injection makeup at start of event.

(2) This post EPU HEP was identical to the pre EPU HEP as the action was required in the same discrete time step. The post EPU HEP was increased by 15% to evaluate the sensitivity of reducing the time within that time step.

(3) This HEP is less than 1E-2 for both pre and post EPU. The 0.1 value has been used in the baseline PRA because of equipment dependencies where auto actuation failure may be non-recoverable. Since this is not affected by EPU there is no change in risk.

(4) There was no change in HEP thus no change in risk

(5) Top event KR split fractions were calculated and used to update master frequency files

(6) Several scenarios and system dependencies are affected, but the timing is conservatively based on loss of high pressure injection.

(7) Time to Level 1 is used as restoring feedwater before Level 1 allows operators to bypass MSIV Level 1 trip (not presently credited in the PRA) if this action is successful. Note that time to -39 inches (blow down required) could be used given present model.

(8) Not modified for Post-EPU, Pre-EPU (Baseline PRA) value applies.

(9) The time allowed is based primarily on bleed-off rates as well as the functional requirements of the system per U2 HRA Notebook.

(10) New MAAP Case post-EPU provides bases for 10 minutes. 4.0E-2 is conservative, new post-EPU value is 3.4E-2.

(11) Special Operating Procedure.

(12) This HEP is not credited.

Key to HRA Methods:

(a) EPRI CBDTM (Parry, G. W., An Approach to the Analysis of Operator Actions in Probabilistic Risk Assessment, EPRI TR-100259, June 1992)

(b) HCR/ORE (Spurgin, A.J., et al., A Human Reliability Analysis Approach Using Measurements For Individual Plant Examination, NP-6560-L, December 1989)

(c) ASEP (Swain, A.D., Accident Sequence Evaluation Program Human Reliability Analysis Procedure, NUREG/CR-4772, SAND86- 1996, February 1987)

(d) THERP (Swain, A.D., Guttmann, H.E., Handbook of Human Reliability Analysis With Emphasis on Nuclear Power Plant Applications, NUREG/CR-1278, August 1983)

(e) Screening Value

ATTACHMENT 4

AFFIDAVIT JUSTIFYING WITHHOLDING PROPRIETARY INFORMATION IN GE-HITACHI NUCLEAR ENERGY AMERICAS LLC DOCUMENT "NMP2 EPU ROUND 2 RAI RESPONSES"

GE-Hitachi Nuclear Energy Americas LLC

AFFIDAVIT

I, James F. Harrison, state as follows:

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

(2) The information sought to be withheld is contained in GEH letter, GE-PPO-1GYEF-KG1-509, G. Carlisle, GEH to M. Gorski, Constellation Energy Nuclear Group, "NMP2 EPU Round 2 RAI Responses" dated February 12, 2010. The proprietary information in Enclosure 1 entitled, RAI Responses to A1, B8, D1 through D5, D7 through D17, E2, E4, E6, E7, E9, E13, F4 and GEH Input to C5 Proprietary, is identified by a dotted underline inside double square brackets, [[This sentence is an example.{3}]]. In each case, the superscript notation {3} refers to Paragraph (3) of this affidavit, which provides the basis for the proprietary determination.

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

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

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

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

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

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

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

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

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

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

(8) The information identified in paragraph (2) above is classified as proprietary because it contains results of an analysis performed by GEH to support Nine Mile Point-2 Extended Power Uprate (EPU) license application. This analysis is part of the GEH EPU methodology. Development of the extended power uprate methodology and the supporting analysis techniques and information, and their application to the design, modification, and processes were achieved at a significant cost to GEH.

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

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

the appropriate evaluation process. In addition, the technology base includes the value derived from providing analyses done with NRC-approved methods.

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

The precise value of the expertise to devise an evaluation process and apply the correct analytical methodology is difficult to quantify, but it clearly is substantial.

GEH's competitive advantage will be lost if its competitors are able to use the results of the GEH experience to normalize or verify their own process or if they are able to claim an equivalent understanding by demonstrating that they can arrive at the same or similar conclusions.

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

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

Executed on this 12th day of February 2010.

James F Harrison

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