Constellation Energy
Nine Mile Point Nuclear Station

P.O. Box 63
Lycoming, NY 13093

April 1, 2005
NMP2L 2120

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

SUBJECT: Nine Mile Point Unit 2
Docket No. 50-410
Facility Operating License No. NPF-69

License Amendment Request Pursuant to10 CFR 50.90: Request for Amendment to Extend Completion Time for Emergency Uninterruptible Power Supply Inverters

Gentlemen:

Pursuant to 10 CFR 50.90, Nine Mile Point Nuclear Station, LLC, (NMPNS) hereby requests an amendment to Nine Mile Point Unit 2 (NMP2) Operating License NPF-69. The proposed change to the Technical Specifications (TSs) contained herein would revise Required Action A.1 of TS 3.8.7, "Inverters - Operating," to extend the Completion Time for one emergency uninterruptible power supply (UPS) inverter inoperable from 24 hours to 7 days. The Bases for TS 3.8.7 will be revised to reflect the proposed changes to the TSs.

This change is being proposed to support on-line corrective maintenance of the emergency UPS inverters and will have a negligible impact on plant safety. The current 24-hour Completion Time is insufficient for restoration of an inoperable inverter as it is not adequate to support the required repair activities and associated post-maintenance testing, which often includes confidence and burn-in runs. Implementation of this proposed Completion Time extension would provide increased operational flexibility for on-line repair of an inoperable emergency UPS inverter and could avert unplanned plant shutdowns.

The justification for extending the Completion Time for an inoperable emergency UPS inverter is based on risk-informed and deterministic evaluations, which incorporate two principal elements: (1) the availability of a dedicated safety-related transformer for powering the inverter loads and (2) the application of the site Configuration Risk Management Program for planned maintenance. These elements provide assurance that the power requirements for the critical instrumentation and control equipment are met during the proposed extended Completion Time.

The risk impact of extending the Completion Time associated with TS 3.8.7 Required Action A.1 was evaluated using the updated NMP2 Level 2 Probabilistic Risk Assessment (PRA) model. The Incremental Conditional Core Damage Probability and Incremental Conditional Large Early Release Probability for each emergency UPS inverter division meet the guidelines of <5.0E-07 and <5.0E-08, respectively, such that the impact on plant risk is considered small,

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consistent with Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications." Furthermore, the evaluation of the changes in Core Damage Frequency and Large Early Release Frequency due to the expected increased inverter unavailability have been shown to meet the risk-acceptance guidelines of <1.0E-06 and <1.0E-07, respectively, provided in Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant Specific Changes to the Licensing Basis." This evaluation supports the increase in the Division 1 and 2 emergency UPS inverter Completion Time from a quantitative, risk-informed perspective consistent with plant operational and maintenance practices.

This amendment request is subdivided as follows:

1. Attachment 1 provides the supporting information and safety analyses for the proposed change.
2. Attachment 2 includes the marked-up TS page for the proposed change.
3. Attachment 3 includes the associated marked-up TS Bases page for information only.
4. Attachments 4 through 8 provide the required PRA quality information and PRA study results.
5. Attachment 9 provides relevant figures from the NMP2 Updated Safety Analysis Report.

Section 5.3 of Attachment 1 provides a list of the regulatory commitments associated with this submittal.

The proposed amendment is similar to the amendment request submitted for the Clinton Power Station on April 26, 2004, and the approved amendments for the Braidwood and Byron Stations (Amendments 129 and 135, respectively) and the North Anna Power Station (Amendments 235 and 217 for Units 1 and 2, respectively).

NMPNS requests approval of this application and issuance of the TS amendment by December 31, 2005. Once approved, the amendment will be implemented within 60 days. Pursuant to 10 CFR 50.91(b)(1), NMPNS has provided a copy of this license amendment request and the associated analyses regarding no significant hazards considerations to the appropriate state representative.

Very truly yours,

James A. Spina
Vice President Nine Mile Point

JAS/DEV/sac

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

I, James A. Spina, being duly sworn, state that I am Vice President Nine Mile Point, and that I am duly authorized to execute and file this request 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.

James A. Spina
Vice President Nine Mile Point

Subscribed and sworn before me, a Notary Public in and for the State of New York and County of Oswego, this 1st day of April, 2005.

WITNESS my Hand and Notarial Seal:

SANDRA A. OSWALD
Notary Public, State of New York
No. 01OS6032276
Qualified in Oswego County
Commission Expires 10/25/05

Notary Public

My Commission Expires: 10/25/05

4/1/05
Date

Attachments:
1. Evaluation of Proposed Technical Specification Changes
2. Proposed Technical Specification Changes (Mark-up)
3. Changes to Technical Specification Bases Pages
4. Nine Mile Point Unit 2 Probabilistic Risk Assessment Peer Review Certification Information
5. NRC Review Comments Summary
6. Updated PRA Results Summary
7. Tier 1: Probabilistic Risk Assessment (PRA) Study Results
8. Dominant CDF and LERF Sequences that Contain the Emergency UPS Inverters
9. NMP2 Updated Safety Analysis Report (USAR) Figures Relevant to the Emergency UPS Inverters

cc: Mr. S. J. Collins, NRC Regional Administrator, Region I
Mr. G. K. Hunegs, NRC Senior Resident Inspector
Mr. P. S. Tam, Senior Project Manager, NRR (2 copies)
Mr. John P. Spath, NYSERDA

ATTACHMENT 1

EVALUATION OF PROPOSED TECHNICAL SPECIFICATION CHANGES

Subject: License Amendment Request Pursuant to 10 CFR 50.90: Request for Amendment to Extend Completion Time for Emergency Uninterruptible Power Supply Inverters

1.0 DESCRIPTION

2.0 PROPOSED CHANGE

3.0 BACKGROUND

4.0 TECHNICAL ANALYSIS

5.0 REGULATORY SAFETY ANALYSIS

6.0 ENVIRONMENTAL CONSIDERATION

1.0 DESCRIPTION

This letter is a request to amend Operating License NPF-69 for Nine Mile Point Unit 2 (NMP2).

The proposed change to the Technical Specifications (TSs) contained herein would revise Required Action A.1 of TS 3.8.7, "Inverters - Operating," to extend the Completion Time for one emergency uninterruptible power supply (UPS) inverter inoperable from 24 hours to 7 days. The Bases for TS 3.8.7 will be revised to reflect the proposed changes to the TSs.

This change is being proposed to support on-line maintenance of the emergency UPS inverters. The current 24-hour Completion Time is insufficient for restoration of an inoperable inverter as it is not adequate to support the required maintenance and associated post-maintenance testing, which often includes confidence and burn-in runs. Implementation of this proposed Completion Time extension will provide operational flexibility by allowing additional time to perform corrective emergency UPS inverter maintenance and post-maintenance testing on-line, thereby improving inverter reliability.

The proposed changes to the TSs and associated changes to the TS Bases are indicated in the marked-up pages provided in Attachments 2 and 3, respectively. The TS Bases changes are provided for information only and do not require NRC issuance as they will be controlled by the NMP2 TS Bases Control Program (TS 5.5.10).

2.0 PROPOSED CHANGE

The proposed change revises Required Action A.1 to extend the Completion Time of TS 3.8.7 for an inoperable emergency UPS inverter from the current 24 hours to 7 days.

In addition to the above, the TS Bases will be revised to document the basis for the proposed Completion Time.

3.0 BACKGROUND

The emergency UPS inverters are the preferred source of power for the Division 1 and 2 120 VAC uninterruptible electrical power distribution subsystems. There is one emergency UPS inverter per divisional 120 VAC uninterruptible electrical power distribution subsystem, making a total of two emergency UPS inverters. The purpose of the emergency UPS inverters is to provide a continuous source of filtered 120 VAC power to the safety-related loads supplied from the associated electrical power distribution subsystems. The onsite power system, including the emergency UPS inverters and associated power supplies and distribution subsystems, are described in Section 8.3 of the NMP2 Updated Safety Analysis Report (USAR). USAR figures relevant to the emergency UPS inverters are provided in Attachment 9.

Each of the two independent emergency UPS inverters is a 25 kVA, 120 VAC, 1-phase unit. As shown on USAR Figure 8.3-5 (see Attachment 9), the inverter can be powered from a safety-related 600 VAC supply via an internal rectifier or from the divisional safety-related 125 VDC battery supply. The inverter is normally fed from the 600 VAC supply via the internal rectifier. If the normal AC supply is lost, the inverter is automatically fed from its backup 125 VDC supply without interruption. If an inverter failure or a large overload is sensed, the static transfer switch will automatically bypass the inverter and transfer the inverter loads to the alternate maintenance supply with no interruption of power to the inverter loads. The maintenance supply is provided from a divisional safety-related 600 VAC emergency lighting panel. A dedicated safety-related transformer is used to convert the maintenance supply 600 VAC input to the required 120 VAC output for powering the inverter loads. Each UPS also includes a manual transfer switch to bypass the static transfer switch, which enables servicing of the static transfer switch or the rectifier and/or inverter without interrupting power to the inverter loads.

The emergency UPS inverters are required to be operable in Modes 1, 2, and 3 to ensure that:

- Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of anticipated operational occurrences (AOOs) or abnormal transients; and

- Adequate core cooling is provided, and containment operability and other vital functions are maintained in the event of a postulated design basis accident (DBA).

The emergency UPS inverters ensure the availability of AC electrical power for the instrumentation and controls of systems required to shutdown the reactor and maintain it in a safe condition after an AOO or a postulated DBA.

Maintaining the emergency UPS inverters operable ensures that the redundancy incorporated into the design of the Emergency Core Cooling System (ECCS) instrumentation and controls is maintained. The two battery powered emergency UPS inverters ensure an uninterruptible supply of 120 VAC electrical power to the associated power distribution subsystems, even if the 4.16 kV emergency buses are de-energized. Operable emergency UPS inverters are required to be aligned to the associated 120 VAC uninterruptible power distribution subsystems, with output voltage and frequency within tolerances, and power input to the emergency UPS inverters from a 125 VDC divisional battery via the associated Class 1E DC bus. Alternatively, power supply may be from the normal 600 VAC source via the internal rectifier, as long as the divisional battery is available as the uninterruptible supply.

Required Action A.1 of TS 3.8.7 currently allows only 24 hours to repair an inoperable Division 1 or 2 emergency UPS inverter and return it to service. As stated in the TS 3.8.7 Bases, the 24-hour limit was based on engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the plant is exposed because of the inverter inoperability.

The proposed change will extend the allowable Completion Time for the TS Required Action associated with restoration of an inoperable Division 1 or Division 2 inverter. Recent experience has shown that the current 24-hour Completion Time for restoration of an inoperable Division 1 or Division 2 inverter is insufficient in some cases to support on-line corrective maintenance and post-maintenance testing while NMP2 is at power. Implementation of this proposed Completion Time extension will provide the following benefits:

- Provide operational flexibility by allowing additional time to perform corrective maintenance and post-maintenance testing on-line, thereby improving inverter reliability.

- Avert unplanned plant shutdowns.

4.0 TECHNICAL ANALYSIS

The emergency UPS inverters are the preferred source of power for the Division 1 and 2 120 VAC uninterruptible electrical power distribution subsystems because of the stability and reliability they achieve. There are two emergency UPS inverters, one for each 120 VAC uninterruptible electrical power distribution subsystem (see USAR Figure 8.3-4 provided in Attachment 9). Each inverter can be powered from a safety-related 600 VAC supply via an internal rectifier or from the divisional safety-related 125 VDC battery supply (see Attachment 9, USAR Figure 8.3-5). The 600 VAC/rectifier or 125 VDC powered inverter provides an uninterruptible power source for the instrumentation and controls for the ECCS, as well as other critical plant loads. Additionally, each 120 VAC uninterruptible electrical power distribution subsystem can be powered from an alternate AC source (maintenance supply) via a dedicated safety-related transformer. The transformer is powered from a safety-related 600 VAC emergency lighting panel, thereby providing an interruptible source of power for the 120 VAC uninterruptible panels. The quality of the power provided by the maintenance supply is comparable to the inverters and has no adverse affect on operation or response of the loads powered by the associated 120 VAC power distribution subsystems.

4.1 Deterministic Evaluation

4.1.1 Defense-in-Depth Evaluation

The impact of the proposed extension of the Completion Time for an inoperable emergency UPS inverter was evaluated and determined to be consistent with the defense-in-depth philosophy. The limited unavailability of a single power source caused by entry into a TS action does not significantly change the balance among the defense-in-depth principles of prevention of core damage, prevention of containment failure, and consequence mitigation.

The defense-in-depth philosophy requires multiple means or barriers to be in place to accomplish safety functions and prevent the release of radioactive material. NMP2 is designed and operated consistent with the defense-in-depth philosophy. The safety-related equipment required to mitigate the consequences of postulated accidents consists of three independent divisional load groups, Divisions 1, 2, and 3. The Division 1 and 2 load groups can each be powered from either of two independent sources (one offsite source or the dedicated onsite diesel generator (DG)). The Division 3 load group, consisting of high pressure core spray (HPCS) system equipment, can be powered from three independent sources (either of the two offsite sources or the dedicated onsite DG). Moreover, the loss of an entire load group (Division 1, 2, or 3) will not prevent the safe shutdown of the plant in the event of a DBA. Accordingly, the unavailability of a single emergency UPS inverter by entry into a TS action statement for inverter maintenance does not reduce the amount of available equipment to a level below that necessary to mitigate a DBA. The other two divisions of safety-related equipment and their associated offsite and onsite power sources will remain available and are designed with adequate independence, capacity, and capability to mitigate postulated accidents. Therefore, consistent with the defense-in-depth philosophy, the proposed change will continue to provide for multiple means to accomplish safety functions and prevent the release of radioactive material in the event of an accident.

The proposed extension of the emergency UPS inverter Completion Time does not introduce any new common cause failure modes, and protection against common cause failure modes previously considered in DBA analyses is not compromised.

Compensatory Measures

Appropriate configuration risk management controls and compensatory measures will be established to assure that system redundancy, independence, and diversity are maintained commensurate with the risk associated with the extended emergency UPS inverter Completion Time. These include TS and Maintenance Rule (10 CFR 50.65) programmatic requirements, as well as administrative controls in accordance with the Configuration Risk Management Program (CRMP).

With an emergency UPS inverter out of service, the safety-related maintenance power supply (via the safety-related transformer) must be powering the loads aligned to the associated 120 VAC uninterruptible power distribution subsystems; otherwise, the Required Actions of TS 3.8.8, "Distribution Systems – Operating," would need to be entered. The maintenance supply is dependent on operation of the associated DG following a loss of offsite power (LOSP) event. Entry into the extended inverter Completion Time concurrent with DG routine maintenance could have an impact on plant safety, since the LOSP event could leave the 120 VAC uninterruptible power distribution subsystem loads without power. Therefore, appropriate plant procedures will include provisions for implementing the restrictions and compensatory measures described in Section 4.2.5 of this Attachment when an emergency UPS inverter is removed from service for any extended Completion Time duration (greater than 24 hours and up to 7 days).

While in the proposed extended emergency UPS inverter Completion Time, additional elective equipment maintenance or testing that requires the equipment to be removed from service will be evaluated and activities that yield unacceptable results will be avoided.

4.1.2 Safety Margin Evaluation

The proposed extension of the emergency UPS inverter Completion Time remains consistent with the codes and standards applicable to the onsite AC sources and electrical distribution subsystems. With one of the required 120 VAC uninterruptible power distribution subsystems being powered from the alternate safety-related maintenance supply, which is backed by the divisional DG, there is no significant reduction in the margin of safety. Testing of the DGs and associated electrical distribution equipment provides confidence that the DGs will start and provide power to the critical loads in the unlikely event of a LOSP during the extended 7-day

Completion Time. In addition, as further discussed below, the proposed extended Completion Time will not erode the reduction in severe accident risk that was achieved with implementation of the Station Blackout (SBO) Rule (10 CFR 50.63) or affect any of the safety analyses assumptions or inputs as described in the NMP2 USAR.

Design Basis Requirements and Safety Analyses Impact

The initial conditions of the DBA and transient analyses described in Chapters 6, "Engineered Safety Features," and 15, "Accident Analyses," of the NMP2 USAR assume the engineered safety feature (ESF) systems are operable. The emergency UPS inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the ESF ECCS instrumentation and controls and other safety-related critical plant loads so that the fuel, reactor coolant system, and containment design limits are not exceeded. The operability of the emergency UPS inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the plant. This includes maintaining the Division 1 and 2 120 VAC uninterruptible electrical power distribution subsystems operable during accident conditions in the event of an assumed loss of all offsite AC power and a worst-case single failure.

The proposed extension of the emergency UPS inverter Completion Time will not affect any safety analyses inputs or assumptions as described in the NMP2 USAR. With an emergency UPS inverter inoperable, its associated 120 VAC uninterruptible distribution subsystem is inoperable if not energized. The maintenance supply provides an alternate (interruptible) source of power to the 120 VAC uninterruptible power distribution subsystems. A LOSP with an inoperable emergency UPS inverter (i.e., the maintenance supply powering the 120 VAC uninterruptible distribution subsystem) will result in an initial loss of power to the loads. Since the maintenance supply is from a safety-related 600 VAC emergency lighting panel, power would be restored to the affected 120 VAC uninterruptible panels once the associated DG re-energizes the 600 VAC emergency lighting panel. Following restoration of power to the 600 VAC emergency lighting panel, all loads supplied by the 120 VAC uninterruptible power distribution subsystem would be restored, with only a slight delay as compared to the response of the other division (i.e., the division with an operable emergency UPS inverter). There would be no adverse impact to the plant since the inverter in the other division would be available to power that division of ESF equipment, and Division 3 would also be available. In order for the 120 VAC uninterruptible power distribution subsystem to remain de-energized following the LOSP, the associated DG would have to fail or there would have to be a failure to re-energize the 600 VAC emergency lighting panel or the maintenance supply would have to fail (e.g., failure of the safety-related transformer).

In the unlikely event of a failure to energize the 120 VAC uninterruptible power distribution subsystem following a LOSP, the most significant impact on the plant is the failure of one division of ESF equipment (Division 1 or Division 2) to actuate. In this condition, the other two divisions of ESF equipment will automatically actuate to mitigate the accident, and the plant would remain within the bounds of the accident analyses. As previously evaluated in the NMP2 USAR, even with a loss of an entire division of safety-related electrical power, the remaining two electrical divisions are capable of supplying the emergency loads required for safe shutdown of the reactor in case of an accident. Because of the low probability of an accident requiring the

ESF equipment occurring simultaneous with a LOSP, a single failure, and inverter maintenance, there is minimal safety impact due to the proposed extension of the Completion Time for an inoperable inverter.

Station Blackout (SBO) Capability Assessment

An SBO is defined as the complete loss of AC electric power to the essential and nonessential switchgear buses in a nuclear power plant. An SBO would result from a LOSP concurrent with a turbine trip and failure of the onsite emergency AC power system. To address the potentially significant risk of core damage associated with an SBO event, the NRC issued the SBO Rule, promulgated as 10 CFR 50.63, "Loss of All Alternating Current Power," and Regulatory Guide 1.155, "Station Blackout." The SBO Rule requires that a licensed nuclear power plant be able to withstand an SBO for a specified time and recover. The ability to cope with an SBO for a certain time period provides additional margin of safety to a potential severe accident should both offsite and onsite emergency AC power systems fail concurrently.

NMP2 is classified as a 4-hour duration coping plant with 0.975 target DG reliability (see USAR Section 8.3.1.5). The SBO coping analysis credits operation of the reactor core isolation cooling (RCIC) system in the manual flow control mode to assure that sufficient water inventory is maintained in the vessel for core cooling. The SBO coping analysis also credits operator action to control reactor pressure vessel (RPV) pressure by manually opening, from the control room, one of the main steam system safety relief valves (SRVs). The Division 1 emergency UPS inverter provides power to the instrumentation and controls required for automatic initiation and operation of the RCIC system and automatic initiation of the Division 1 automatic depressurization system (ADS) SRVs. In the event of an SBO with the Division 1 emergency UPS inverter out of service, automatic initiation of the RCIC system is defeated due to the loss of power to the governor and flow controller. To ensure the RCIC system remains capable of manual initiation and operation for the 4-hour SBO coping duration, a dedicated portable power supply will be connected to provide a continuous source of power to the RCIC system governor and flow controller. Operator actions associated with establishing this power supply will have been evaluated in accordance with the guidance of NUREG/CR-6689, "Proposed Approach for Reviewing Changes to Risk-Important Human Actions," to demonstrate that there is a high probability (> 0.9) of successfully performing these operator actions. Furthermore, the capability to manually open one of the seven ADS SRVs and eleven non-ADS SRVs for RPV pressure control would be unaffected, except that the number of times that one of the nine Division 1 SRVs could be opened would be limited. This is because the SRVs open on nitrogen pressure and the associated nitrogen make-up valves fail closed on loss of power, resulting in the inability to recharge the affected SRV nitrogen accumulators. In addition, in the event that the RCIC system is not functional during an SBO, the RPV can be depressurized by operation of SRVs and RPV makeup can be provided using the diesel fire pump (DFP) via the fire water to residual heat removal (RHR) system cross-tie.

Note that, because the RCIC system is only powered from Division 1, an SBO event with the Division 1 emergency UPS inverter out of service is more limiting than if the event occurred with the Division 2 emergency UPS inverter out of service. A postulated SBO event with the

Division 2 emergency UPS inverter out of service would have limited impact on the SBO event due to the loss of power to reactor vessel high water level (Level 8) instrumentation.

Therefore, the proposed extended Completion Time for an inoperable emergency UPS inverter is consistent with approved NRC staff positions regarding power source operability. Accordingly, the proposed change will have no adverse impact on the assumptions or conclusions of the SBO coping analysis or erode the reduction in severe accident risk that was achieved with implementation of the SBO Rule (10 CFR 50.63).

4.2 Probabilistic Risk Assessment (PRA)

To further assess the overall impact on plant safety of the proposed extended emergency UPS inverter Completion Time, a PRA was performed consistent with the guidance pertaining to risk-informed criteria specified in Regulatory Guide 1.177, "An Approach for Plant-Specific Risk-Informed Decisionmaking: Technical Specifications." The PRA provides a quantitative evaluation of the risk associated with the change in terms of average Core Damage Frequency (CDF) and average Large Early Release Frequency (LERF) produced by the extension of the Completion Time for an inoperable emergency UPS inverter. This evaluation included consideration of the Maintenance Rule program established pursuant to 10 CFR 50.65(a)(4) to control the performance of other potentially high risk tasks during an inverter outage, as well as consideration of specific compensatory measures to minimize risk. All of these elements were included in a risk evaluation using the three-tiered approach suggested in Regulatory Guide 1.177, as follows:

Tier 1 - PRA Capability and Insights
Tier 2 - Avoidance of Risk-Significant Plant Configurations
Tier 3 - Risk-Informed CRMP

Evaluations addressing each of these tiers are provided below. The PRA model serves as the primary tool for these evaluations. Therefore, in order to establish the qualification of the PRA model, supplemental background information related to the development, certification, application, and quality of the PRA model in place at NMP2 is presented first.

4.2.1 PRA Model Development

The NMP2 PRA is based on a detailed model of the plant that was developed from the NMP2 Individual Plant Examination (IPE) and NMP2 Individual Plant Examination for External Events (IPEEE) projects. The PRA model has undergone NRC review and Boiling Water Reactor Owner's Group (BWROG) certification. A summary of the NRC review comments are provided in Attachment 5 and the PRA peer review certification "A" and "B" Facts and Observations are provided in Attachment 4. The model was updated to incorporate review comments, current plant design, current procedures, recent plant operating data, current PRA techniques, and general improvements identified by the Nine Mile Point PRA team.

Key milestones for the development of the NMP2 PRA model are as follows:

- IPE submitted to the NRC in July 1992.
- IPE Safety Evaluation Report (SER) received from the NRC in August 1994.
- IPEEE submitted to the NRC in June 1995.
- BWROG certification issued in May 1997.
- IPEEE SER received from the NRC in August 1998.
- NMP2 PRA model major update completed in August 1998 – Model U2L1497.
- NMP2 PRA model limited update for proposed DG Completion Time extension completed in July 2002 - Model U2PRA01A.
- NMP2 PRA model limited update to correct ECCS room cooling dependencies related to service water – Model U2PRA01B.

In addition to the above updates, the following enhancements have been incorporated into the NMP2 PRA model:

- Additional initiating event contributions were included in basic event importance quantifications.
- Multi-state conditional split fractions were replaced with multi-state boundary condition approaches.
- Incorporation of exact system quantification using Binary Decision Diagram.

Key goals of the PRA model development process were to:

- Understand the underlying plant risks and key sources of uncertainty.
- Identify areas where cost-effective risk improvement opportunities exist.
- Develop a tool to quantify nuclear safety and support a comprehensive risk management program.
- Establish an in-house risk analysis capability to support plant decisionmaking.

An independent assessment of the NMP2 PRA, using the self-assessment process developed as part of the BWROG peer review certification program, was completed to assure that the NMP2 PRA was comparable to other PRA programs in use throughout the industry. The NMP2 PRA was certified by the BWROG in May 1997 following an inspection and review by a PRA peer review certification team. The certification review results were documented and evaluated for inclusion in the PRA model major update completed in 1998. The findings from the review primarily related to improvements in the areas of guidance, documentation, models, and the capturing of plant changes. Overall, the certification review provided high technical marks on the PRA, and there were no findings that significantly impacted the PRA results. The certification team assigned a Grade 3 to the NMP2 PRA, which is deemed suitable for applications such as single TS actions if supported by deterministic evaluations. Attachment 4 provides the key findings from the PRA certification inspection and review (significance level A and B findings and observations) and includes a summary of the qualifications and experience of the certification team members.

4.2.2 <u>PRA Model Maintenance</u>

The PRA model is applied and controlled as defined in administrative procedure NIP-REL-02, "Probabilistic Risk Assessment Program," and engineering department procedure NEP-REL-01, "Evaluations, Analysis, and Update of the Probabilistic Risk Assessment (PRA) Program." Ongoing assessments of the PRA model and reports are part of the normal duties of the PRA engineers. When a change to plant procedures, plant design, or operational data is identified that impacts the PRA model, the PRA engineer uses the guidance in the following table to prioritize the change and assist in the development of an implementation schedule.

Grade	Definition	Action
1	Extremely important and necessary to address to assure the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process.	Immediate update considered.
2	Important and necessary to address, but may be deferred to the next planned PRA update.	Consider in next planned update.
3	Considered desirable to maintain maximum flexibility in PRA applications and consistency with the industry, but is not likely to significantly affect results or conclusions.	Consider in next 2-3 planned updates.
4	Editorial or minor technical item, low priority.	Consider as update opportunity exists.

Planned updates to the PRA model are scheduled on a regular basis by the PRA team. Planned updates include an information gathering phase that is intended to capture plant changes that had not been previously identified by the PRA team. The normal scheduled (planned) update considers all aspects of the PRA.

An unplanned update is undertaken when a Grade 1 item is identified for immediate update. An unplanned update may also be undertaken to address a need for a specific application of the PRA. An unplanned update is considered a limited scope update and does not necessarily include a detailed plant information review or consideration of all aspects of the PRA. This type of update is intended to augment the PRA between normal planned updates as needed. A summary of the updated PRA model is provided in Attachment 6.

4.2.3 <u>PRA Model Application</u>

The NMP2 Level 2 PRA model was used to determine the risk associated with removing an emergency UPS inverter from service for planned or corrective maintenance in accordance with the proposed 7-day Completion Time. The risk measures used are CDF and LERF. The base CDF is 3.5E-5/yr and the base LERF is 8.3E-7/yr. The PRA model is a consolidation of the NMP2 IPE and IPEEE, which explicitly includes fires and seismic events. A description of the CRMP is provided in Section 4.2.6 of this Attachment.

The PRA model is used by NMP2 work control and operations personnel throughout the online work planning and implementing processes. The PRA model is implemented through the use of a Safety Monitor and color codes as described in administrative procedure GAP-PSH-03, "Control of On-Line Work Activities." The results obtained from the PRA model are used along with other inputs, such as TS requirements and operator system knowledge, in a blended approach to determine the final work schedule. The PRA model is currently not applicable to shutdown conditions; thus, the risk assessments for work activities during plant outages are performed consistent with the defense-in-depth philosophy as described in administrative procedure NIP-OUT-01, "Shutdown Safety."

The guidance contained in Regulatory Guides 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and 1.177 was utilized to assure that the results of the PRA model are acceptable to support the proposed extension of the emergency UPS inverter Completion Time, as described below.

4.2.4 Tier 1: PRA Capability and Insights

As noted previously, risk-informed support for the proposed extension of the Completion Time for an inoperable emergency UPS inverter is based on PRA calculations performed to quantify the change in average CDF and average LERF. To determine the effect of the proposed change with respect to plant risk, the guidance provided in Regulatory Guides 1.174 and 1.177 was used.

PRA Results

An evaluation was performed based on the assumption that the full extended Completion Time (i.e., 7 days) would be applied once per inverter per refueling cycle. The total fuel cycle time was calculated to be the number of operating days based on the current 24-month fuel cycle (allowing for planned and unplanned plant outages). The incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) were calculated as recommended in Regulatory Guide 1.177. The results of the risk evaluation are presented in Attachment 7. These results were compared against the risk significance criteria in Regulatory Guide 1.174 for changes in the annual average CDF and LERF and Regulatory Guide 1.177 for ICCDP and ICLERP. The ICCDP and ICLERP were calculated for both the Division 1 and Division 2 emergency UPS inverters, which indicate that an outage of the Division 1 inverter is more limiting. Based on the limiting calculated values for the ICCDP and ICLERP, the proposed extended Completion Time has only a small quantitative impact on plant risk. The following table summarizes the results of the risk evaluation:

Risk Metric	**Acceptance Criterion**	**Evaluation Results**
ΔCDF_{Ave}	< 1.0E-6/yr	4.2E-7/yr
$\Delta LERF_{Ave}$	< 1.0E-7/yr	4.9E-9/yr
$ICCDP_{Div\ 1}$	< 5.0E-7	3.0E-7[(1)]
$ICCDP_{Div\ 2}$	< 5.0E-7	4.9E-7[(1)(2)]
$ICLERP_{Div\ 1}$	< 5.0E-8	3.2E-9
$ICLERP_{Div\ 2}$	< 5.0E-8	5.1E-9

(1) The portable power supply compensatory measure credited in the PRA evaluation has more impact on the Division 1 inverter failure analysis than on the Division 2 inverter failure analysis. Thus, the Division 1 inverter ICCDP is lower than that for the Division 2 inverter.

(2) When entering the extended emergency UPS inverter Completion Time (greater than 24 hours and up to 7 days), the compensating measures and configuration risk management controls described in Section 4.2.5 below will apply. Many of the identified measures and controls were not credited in the PRA evaluation. Thus, there is inherent conservatism in the PRA results, such that the relatively small margin to the ICCDP acceptance criterion is acceptable.

Uncertainty and Sensitivity Analysis

While no formal uncertainty quantification was performed, the PRA model inputs generally have a range factor (defined as the ratio of the 95^{th} confidence to 5^{th} confidence levels) of approximately 10 or less. Thus, propagation of this uncertainty through the dominant sequences would lead to results with a range factor of 10 or less. More importantly, since the proposed extension of the emergency UPS inverter Completion Time involves a change in the risk calculation, the uncertainty distribution is less of an issue because the uncertainty parameters will act on the baseline model and the emergency UPS inverter out of service model uniformly. In addition, model uncertainty and completeness uncertainty have been minimized through the certification and update processes discussed above.

Several sensitivity analyses were performed:

1. Actual emergency UPS inverter maintenance completion time (decrease) - The actual completion time for an inverter is decreased to a most-likely duration of 4 days to estimate the sensitivity. This represents a risk reduction margin.
2. Actual emergency UPS inverter out-of-service time (increase) - The average CDF impact is assessed for two 7-day completion time extensions (14 days total). The risk increase is minimal.
3. Emergency UPS inverter failure rate (increase) – The inverter failure rate is doubled. There is minimal impact on ΔCDF_{AVE} and $ICCDP_{I}$.

These sensitivity analyses are summarized in the following table.

Sensitivity Analysis Summary

Case	Case	Impact	After Change	Before Change	Difference
1	Actual Completion Time (decrease)	Set UPS inverter outage time to 4 days.	ΔCDF_{AVE}=2.4E-7/yr $ICCDP_{II}$ =2.8E-7	ΔCDF_{AVE}=4.2E-7/yr $ICCDP_{II}$ =4.9E-7	Δ = -1.8E-7/yr Δ = -2.1E-7
2	Actual Out-of-Service Time (increase)	Set total UPS inverter outage time to 14 days.	ΔCDF_{AVE}=8.5E-7/yr	ΔCDF_{AVE}=4.2E-7/yr	Δ = 4.3E-7/yr
3	UPS Inverter Failure Rate	Double UPS A and B inverter failure rate.	ΔCDF_{AVE}= 4.3E-7/yr $ICCDP_{I}$ = 3.2E-7 $ICCDP_{II}$= 5.0E-7	ΔCDF_{AVE}=4.2E-7/yr $ICCDP_{I}$ = 3.0E-7 $ICCDP_{II}$= 4.9E-7	Δ = 1.0E-8/yr Δ = 2.0E-8 Δ = 1.0E-8

Note that the LOSP frequency, non-recovery probability, and DG failure probability are important factors contributing to the CDF, due to the SBO-related sequences. Any variation in these parameters will have a directly proportional impact on the CDF. The compensating measures and configuration risk management controls described in Section 4.2.5 below will minimize the factors that could potentially adversely impact the LOSP frequency and DG failure probability. Since the LOSP frequency and non-recovery probabilities were developed from the latest data contained in NUREG/CR-INEEL/EXT-04-02525, "Station Blackout Risk Evaluation for Nuclear Power Plants (Draft)," January 2005, there is a high confidence in these values. The probability of a failure of all emergency AC power used in the NMP2 PRA model correlates well with this guidance.

Transition and Shutdown Risk

The proposed change to extend the emergency UPS inverter Completion Time will reduce the probability of an unplanned manual shutdown initiated by online inverter unavailability. The risk associated with an unplanned manual shutdown has been included in the NMP2 PRA and can be considered here. Unplanned manual shutdowns are included in the scram initiators (i.e., SCRAM and BSCRAM). These initiators contribute to a manual shutdown related conditional core damage probability (CCDP) of 6.2E-7/yr in the revised baseline NMP2 PRA used in this analysis. The CCDP associated with a shutdown with an inoperable emergency UPS inverter would be somewhat higher. Thus, the incremental risk associated with extending the inverter online Completion Time would be at least partially offset by a reduction in risk associated with a shutdown with an inoperable UPS inverter.

4.2.5 Tier 2: Avoidance of Risk-Significant Plant Configurations

As previously discussed, a CRMP is in place at NMP2 for compliance with the Maintenance Rule (10 CFR 50.65), and in particular, for compliance with paragraph (a)(4) of the rule. The CRMP provides assurance that risk-significant plant equipment configurations are precluded or minimized when plant equipment is removed from service. Accordingly, any increase in risk posed by the removal of an emergency UPS inverter from service and the potential combinations of other equipment out of service will be managed in accordance with the CRMP.

The following compensating measures and configuration risk management controls have been credited in the PRA evaluation, and will apply when entering the proposed extended emergency UPS inverter Completion Time (greater than 24 hours and up to 7 days):

1. The RCIC system is available and no planned maintenance or testing activities are scheduled.

2. A dedicated portable power supply is available to provide power to the RCIC system governor and flow controller in the event of an SBO with the Division 1 emergency UPS inverter out of service.

3. Operating crew briefings are conducted on the following important operator actions required during an SBO:

   - Manual RCIC system initiation and operation, including RPV water level control, the use of local RPV level indication, and prevention of RPV overfill.

   - Set-up and connection of the portable power supply for the RCIC system governor and flow controller.

The following additional compensating measures and configuration risk management controls, though not credited in the PRA evaluation, will also apply to the extent possible (considering equipment that may already be out of service) when entering the proposed extended emergency UPS inverter Completion Time (greater than 24 hours and up to 7 days):

1. The other (opposite division) emergency UPS inverter is operable and no planned maintenance or testing activities are scheduled.

2. All three divisional DGs are available and no planned maintenance or testing activities are scheduled.

3. All three required divisional battery chargers are available and no planned maintenance or testing activities are scheduled.

4. Both offsite power circuits are available and no planned maintenance or testing activities are scheduled (115 kV transmission system and associated plant and switchyard equipment).

5. There are no planned maintenance or testing activities which could cause a plant scram, main turbine or generator trip, main steam isolation valve closure, or loss of the divisional batteries or the divisional AC or DC switchgear, except for required surveillances.

6. The NMP2 DFP is available as a makeup source to the reactor pressure vessel.

7. RHR system trains A and B are available and no planned maintenance or testing activities are scheduled.

8. All required service water pumps are available and no planned maintenance or testing activities are scheduled.

9. No hot work permits will be active for the control building and the normal switchgear rooms.

10. Operating crew briefings are conducted on the following important operator actions required during an SBO:

    - Alignment of the NMP2 DFP to the RPV, including use of the Nine Mile Point Unit 1 DFP and crosstie.

- AC power recovery (offsite power and DGs).

- HPCS crossties to Division 1 or 2.

- Emergency depressurize RPV.

While in the proposed extended emergency UPS Completion Time, additional elective equipment maintenance or testing that requires the equipment to be removed from service will be evaluated and activities that yield unacceptable results will be avoided.

The dominant sequences in the NMP2 PRA have been evaluated to assure that important equipment is identified and evaluated when an emergency UPS inverter is out of service. Tables 1 through 4 of Attachment 8 provide the initiating event frequency for the CDF sequences greater than 1E-07/yr and LERF sequences greater than 1E-08/yr that contain the emergency UPS inverter. Two types of evaluations are considered:

1. Important systems and equipment are assessed to determine whether their unreliability has increased since the last PRA update based on plant operational experience.

2. Important equipment and human actions are assessed to determine whether compensating measures can be credited to reduce risk while the emergency UPS inverter is out of service.

Based on Tables 1 through 4 (Attachment 8), the following are identified as major risk contributors when an emergency UPS inverter is out of service:

- Loss of offsite power initiating event (BLOSP or LOSP)
- Instrument air initiating events (ASX)
- Emergency diesel generator (A1, A2, HPCS)
- Loss of feedwater event (LOF)
- RCIC (U1, IC)
- Failed Operator actions:
  - Align DFP to RPV (S1)
  - AC power recovery (offsite power and DGs)
  - Align Division 3 (HPCS) DG to Division 1 or 2
  - Emergency depressurize RPV (OD)

Each of the above-identified risk contributors is further discussed below.

<u>LOSP Initiating Event (BLOSP or LOSP)</u>

The LOSP frequency for the NMP2 baseline model was updated based on the data contained in draft NUREG/CR-INEEL/EXT-04-02525, "Station Blackout Risk Evaluation for Nuclear Power Plants," January 2005. These data include the August 2003 LOSP event. The resulting total

LOSP frequency used in this analysis is 5.68E-2/yr. The NMP2 baseline model was also revised to utilize the higher non-recovery probabilities contained in the draft NUREG.

<u>Instrument Air Initiating Events (ASX)</u>

The loss of instrument air results in the loss of feedwater. Subsequent failures of RCIC and HPCS require operators to depressurize the RPV to provide low pressure makeup. There have been no recent reliability problems identified which relate to the instrument air system and the frequency for this initiating event remains unchanged.

<u>Emergency Diesel Generator (A1, A2, HPCS)</u>

When an emergency UPS inverter is taken out of service, all three DGs will be operable. The PRA calculations did not take credit for this compensatory measure. There are no recent DG reliability problems, so DG reliability remains unchanged. The DG failure rate in the NMP2 PRA is comparable with that in draft NUREG/CR-INEEL/EXT-04-02525.

<u>Loss of Feedwater Event (LOF)</u>

The loss of feedwater and the subsequent failure of RCIC and HPCS require operators to depressurize the RPV to provide low pressure makeup. There have been no recent reliability problems identified which relate to the feedwater system and the frequency for this initiating event remains unchanged.

<u>RCIC (U1, IC)</u>

Successful RCIC (U1) system operation during an SBO is very important because it provides time for the operators to align the DFP as a backup in case of a subsequent RCIC failure before AC power is recovered. When an emergency UPS inverter is taken out of service, RCIC will be operable and a compensatory measure (a portable power supply to power the RCIC governor and flow controller) will be implemented to ensure that the RCIC system remains capable of manual initiation and operation for the SBO coping period. The PRA calculations take credit for establishing this power supply within 30 minutes, with a 0.9 probability of success. Operator actions required to establish this power supply may include set-up of the portable power source, running extension cords, and manually operating 120 VAC panel disconnects. A human factors evaluation will have been performed to ensure that there is a high probability (> 0.9) of successfully performing these operator actions. Functionality of the portable power supply will be periodically verified, and all necessary materials will be appropriately staged.

In the baseline NMP2 PRA model, RCIC is assumed failed given a loss of the Division 1 emergency UPS inverter in an SBO scenario. This assumption is modified allowing credit to be taken to recover RCIC based on the compensatory measure to provide temporary power to the RCIC system governor and flow controller. Accordingly, Top Event U1 was modified with a new split fraction. For conservatism, RCIC recovery credit was not taken for non-SBO scenarios, and Top Event IC was not changed.

The Division 2 emergency UPS inverter supplies power to the RPV Level 8 instrumentation. Loss of the Level 8 trip signal would require operator action to prevent RCIC overfill of the RPV. Current NMP2 emergency operating procedures and associated operator training provide direction for controlling RPV level using the RCIC system. As such, the operator action failure probability to prevent RPV overfill to Level 8 during an SBO is reduced from 0.8 to 0.2.

Operator Actions

Several operator actions have been identified as potentially important. A prescribed operator briefing and special precautions to be observed when taking an emergency UPS inverter out of service can improve operator reliability as compensatory measures against failed actions. The following are some of the operator actions:

- Align DFP to RPV (S1)
- AC power recovery (offsite power and DGs)
- Align Division 3 (HPCS) DG to Division 1 or 2
- Emergency depressurize RPV (OD)

No credit was taken for the operator briefing and special precautions. The operator reliability data used in this analysis is conservative and contributes to extra margin in the analysis.

4.2.6 Tier 3: Risk-Informed CRMP

Consistent with 10 CFR 50.65(a)(4), and as indicated above, Nine Mile Point Nuclear Station, LLC (NMPNS) has developed a CRMP which provides assurance that the risk impact of out of service equipment is properly evaluated prior to performing a work activity. The administrative procedures and instructions governing this process are GAP-PSH-03, "Control of On-line Work Activities," GAP-OPS-117, "Integrated Risk Management," NAI-PSH-02, "Use of the Safety Monitor," and NIP-OUT-01, "Shutdown Safety." The guidance provided in GAP-PSH-03 and GAP-OPS-117 provides assurance that the risk associated with planned online work activities is evaluated and that the work activities are scheduled appropriately. The CRMP includes an integrated review (i.e., both probabilistic and deterministic) to identify risk-significant equipment outage configurations in a timely manner during the online work management process for both planned and emergent work. Appropriate consideration is given to equipment unavailability, operational activities (e.g., testing, load dispatching), and weather conditions. The CRMP includes provisions for performing a configuration-dependent assessment of the overall impact on risk of proposed plant configurations prior to, and during, the performance of online work activities that remove equipment from service. Risk is re-assessed if an equipment failure or malfunction, or other emergent condition, produces a plant configuration that had not been previously assessed.

For online work activities, a quantitative risk assessment is performed to assure that the activity does not pose an unacceptable risk. This evaluation is performed using the Safety Monitor. The results of the risk assessment are classified by color code in order of the increased risk of the activity. These color code classifications are described in the following table:

Color Code	Level Criteria	Action
GREEN	CDF < 2 X PRA Baseline (maintenance included)	Risk level is acceptable, no further actions are necessary.
YELLOW	CDF ≥ 2 X PRA Baseline; CDF < 10 X PRA Baseline (maintenance included)	Risk level is high, requires supporting PRA analysis of acceptable duration.
RED	CDF ≥ 10 X PRA Baseline (maintenance included)	Significant risk level, work may require plant outage to perform. Online requires supporting PRA analysis, compensatory action recommendations, and plant management approval to perform.

Emergent work is reviewed by work management and operations to evaluate the impact on the risk assessment performed during the schedule development process. Prior to beginning any work, the work scope and schedule are reviewed to assure that nuclear safety and plant operations remain consistent with regulatory requirements, as well as management expectations.

4.3 Maintenance Rule Program Controls

The 10 CFR 50.65 Maintenance Rule performance and monitoring criteria at NMP2 are controlled by Maintenance Rule Manual Procedure S-MRM-REL-0105, "Maintenance Rule Performance Criteria." The reliability and availability of the NMP2 UPS are monitored under the Maintenance Rule program as described in administrative procedures NIP-REL-01, "Maintenance Rule," S-MRM-REL-0101, "Maintenance Rule," and S-MRM-REL-0105.

The NMP2 Maintenance Rule program establishes reliability criteria at the Functional Failure (FF) level rather than at the Maintenance Preventable Functional Failure level. This provides assurance that all emergency UPS inverter FFs are assessed for possible 10 CFR 50.65(a)(1) goal setting and monitoring under the Maintenance Rule program, regardless of maintenance preventability. Any failure which causes loss of power to loads or the inability to power the emergency UPS inverter from the DC electrical distribution system, even though the loads remain energized, would be classified as a FF. The emergency UPS inverter system is currently classified in 10 CFR 50.65(a)(1) status (i.e., system performance and condition is being monitored to assure capability of fulfilling intended functions) for exceeding the performance criterion of one FF for each Division during the past 24 months. There have not been any events that resulted in a loss of power to the inverter loads.

The Division 1 emergency UPS inverter has not incurred any unavailability in the past 24-month rolling period while NMP2 was on line.

The Division 2 emergency UPS inverter was taken out of service in August 2003 (2 times), August 2004, September 2004, and January 2005 for unplanned maintenance during the past 24-month rolling window while NMP2 was on line. Three of these five unavailability periods were for durations greater than 24 hours, and the average duration was 22.4 hours. In addition, the

Division 2 inverter was taken out of service for planned corrective maintenance for 5.5 hours in August 2003. The accumulated unavailability for the Division 2 inverter was 117.6 hours during the past 24-month rolling window, resulting in the inverter being 0.72% unavailable.

A modification is in progress to install redundant emergency UPS inverters in each electrical division to improve overall system reliability and availability. The necessary tie-in points were installed during the last refueling outage to facilitate online installation of the inverters. The inverters are currently scheduled for installation in the summer of 2005.

Installation of the redundant emergency UPS inverters will allow NMPNS to perform planned maintenance on the inverters with minimal impact on unavailability. It is expected that this modification will reduce unplanned outage time and improve reliability and availability under the Maintenance Rule program.

4.4 Conclusion

The proposed extension of the emergency UPS inverter Completion Time is based upon both a deterministic evaluation and a risk-informed assessment. The deterministic evaluation concluded that the proposed change is consistent with the defense-in-depth philosophy, in that (1) there continue to be multiple means available to accomplish the required safety functions and prevent the release of radioactive material in the event of an accident and (2) multiple barriers currently exist and additional barriers will be provided to minimize the risk associated with entering the extended emergency UPS inverter Completion Time so that protection of the public health and safety is assured. The deterministic evaluation also concluded that the proposed change will not erode the reduction in severe accident risk that was achieved with implementation of the SBO Rule or affect any of the safety analyses assumptions or inputs as described in the USAR. The risk-informed assessment concluded that the increase in plant risk is small and consistent with the NRC "Safety Goals for the Operations of Nuclear Power Plants; Policy Statement," Federal Register, Vol. 51, p. 30028 (51 FR 30028), August 4, 1986, as further described in Regulatory Guides 1.174 and 1.177. When taken together, the results of the deterministic evaluation and risk-informed assessment provide high assurance that the equipment required to safely shutdown the plant and mitigate the effects of a DBA will remain capable of performing their safety functions when an emergency UPS inverter is out of service for maintenance or repairs in accordance with the proposed extended Completion Time.

The proposed extension of the emergency UPS inverter Completion Time is consistent with NRC policy and will continue to provide protection of the public health and safety. The proposed change advances the objectives of the NRC's PRA Policy Statement, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Volume 60, p. 42622 (60 FR 42622), August 16, 1995, for enhanced decisionmaking and results in more efficient use of resources and reduction of unnecessary burden. The capability of performing on-line corrective maintenance on the emergency UPS inverters is expected to avert unplanned plant shutdowns and improve inverter reliability.

Therefore, based on the above evaluations and conclusions, NMPNS believes that the proposed change is acceptable and operation in the proposed manner will not present undue risk to public health and safety or be inimical to the common defense and security.

5.0 REGULATORY SAFETY ANALYSIS

5.1 No Significant Hazards Consideration Analysis

Nine Mile Point Nuclear Station, LLC, (NMPNS), is requesting a revision to Facility Operating License No. NPF-69 for Nine Mile Point Unit 2 (NMP2). The proposed change would revise Required Action A.1 of Technical Specification 3.8.7, "Inverters – Operating," to extend the Completion Time for one emergency uninterruptible power supply (UPS) inverter inoperable from 24 hours to 7 days.

NMPNS has evaluated whether or not a significant hazards consideration is involved with the proposed amendment by focusing on the three standards set forth in 10 CFR 50.92, "Issuance of amendment," as discussed below:

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

   Response: No.

   The proposed change does not affect the design of the emergency UPS inverters, the operational characteristics or function of the inverters, the interfaces between the inverters and other plant systems, or the reliability of the inverters. An inoperable emergency UPS inverter is not considered an initiator of an analyzed event. In addition, Required Actions and the associated Completion Times are not initiators of previously evaluated accidents. Extending the Completion Time for an inoperable emergency UPS inverter would not have a significant impact on the frequency of occurrence for an accident previously evaluated. The proposed change will not result in modifications to plant activities associated with inverter maintenance, but rather, provides operational flexibility by allowing additional time to perform inverter corrective maintenance and post-maintenance testing on-line and could avert unplanned plant shutdowns.

   The proposed extension of the Completion Time for an inoperable emergency UPS inverter will not significantly affect the capability of inverters to perform their safety function, which is to ensure an uninterruptible supply of 120 VAC electrical power to the associated power distribution subsystems. A probabilistic risk assessment was performed which concluded that the increase in plant risk is small and consistent with the NRC "Safety Goals for the Operation of Nuclear Power Plants; Policy Statement," Federal Register, Vol. 51, p. 30028 (51 FR 30028), August 4, 1986, as further described in NRC Regulatory Guides 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and 1.177, "An Approach for Plant-Specific, Risk-Informed Decision-Making: Technical Specifications." A deterministic evaluation concluded that plant defense-in-depth philosophy will be maintained with the proposed Completion Time extension.

Therefore, operation in accordance with the proposed change would not involve a significant increase in the probability or consequences of an accident previously evaluated.

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

   Response: No.

   The proposed change does not alter the design, configuration, or method of operation of the emergency UPS inverters or their associated 120 VAC uninterruptible power distribution subsystems, nor does the change alter any safety analyses inputs and assumptions. The proposed extended emergency UPS inverter Completion Time does not reduce the number of emergency UPS inverters below the minimum required for safe shutdown or accident mitigation, and does not affect the parameters within which NMP2 is operated or the setpoints at which protective or mitigative actions are initiated. The use of the alternate safety-related maintenance supply to power the 120 VAC uninterruptible power distribution subsystem is consistent with the NMP2 design. If a Station Blackout (SBO) event occurred while an emergency UPS inverter is out of service, a dedicated portable power supply would be connected to provide a continuous source of power to the reactor core isolation cooling system governor and flow controller to ensure continued system operation. Minor plant modifications installed to facilitate this portable power supply connection will not introduce any new component failure modes or system interactions affecting the ability to safely shut down the plant or mitigate design basis accidents. Operator actions associated with establishing this power supply are of the same type already credited in the SBO coping analysis. These operator actions will have been evaluated in accordance with the guidance of NUREG/CR-6689, "Proposed Approach for Reviewing Changes to Risk-Important Human Actions," thereby assuring a high likelihood of success. Accordingly, no new failure modes, system interactions, or accident responses will be created that could result in a new or different kind of accident.

   Therefore, operation in accordance with the proposed change would not create the possibility of a new or different kind of accident from any previously evaluated.

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

   Response: No.

   Margins of safety are established in the design of components, the configuration of components to meet certain performance parameters, and in the establishment of setpoints to initiate alarms or actions. The proposed change does not alter the design or configuration of the emergency UPS inverters or their associated 120 VAC uninterruptible power distribution subsystems, and does not alter the setpoints at which alarms and associated actions are initiated. With one of the required 120 VAC uninterruptible power distribution subsystems being powered from the alternate safety-related maintenance supply, which is backed by the divisional diesel generator (DG), there is no significant reduction in the margin of safety. Testing of the DGs and associated electrical distribution equipment provides confidence that the DGs will start and provide power to the associated equipment in the unlikely event of a loss of offsite power during the extended 7-day Completion Time.

Applicable regulatory requirements will continue to be met, adequate defense-in-depth will be maintained, sufficient safety margins will be maintained, and any increases in risk are small and consistent with the NRC Safety Goal Policy Statement. Furthermore, during the proposed extended Completion Time for the emergency UPS inverter, any increases in risk posed by potential combinations of equipment out of service will be managed in accordance with the NMPNS site Configuration Risk Management Program, consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," paragraph (a)(4).

Therefore, operation in accordance with the proposed change would not involve a significant reduction in a margin of safety.

5.2 Applicable Regulatory Requirements/Criteria

The proposed change has been evaluated to determine whether applicable regulations and requirements continue to be met. To fully evaluate the effect of the proposed emergency UPS inverter Completion Time extension, PRA methods and a deterministic analysis were utilized. NMPNS has determined that the proposed change does not require any exemptions or relief from regulatory requirements, other than the Technical Specifications, and does not affect conformance with any General Design Criteria differently than described in the NMP2 USAR.

Applicable regulatory requirements will continue to be met, adequate defense-in-depth will be maintained, sufficient safety margins will be maintained, and any increase in risk is small and consistent with the NRC "Safety Goals for the Operation of Nuclear Power Plants; Policy Statement," Federal Register, Vol. 51, p. 30028 (51 FR 30028), August 4, 1986, as further described in NRC Regulatory Guides 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and 1.177, "An Approach for Plant-Specific, Risk-Informed Decision-Making: Technical Specifications." The ICCDP and ICLERP for each inverter division meet the regulatory guidelines such that the impact on plant risk is considered small. Hence, the guidelines of Regulatory Guide 1.177 for the increased inverter Completion Time have been met. Furthermore, the evaluation of changes in CDF and LERF due to the expected increased inverter unavailability, as mitigated by the compensating measures assumed in the analysis, have been shown to meet the risk significance criteria of Regulatory Guide 1.174.

NMPNS utilizes a CRMP consistent with 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," paragraph (a)(4). The goals of this program are to ensure that risk-significant plant configurations will not be entered for planned maintenance activities, and appropriate actions will be taken should unforeseen events place the plant in a risk-significant configuration during the proposed extended emergency UPS inverter Completion Time. To ensure the Completion Time does not degrade operational safety over time, the Maintenance Rule program will be used, as discussed above, to identify and correct adverse trends. Compliance with the Maintenance Rule not only optimizes reliability and availability of important equipment, it also results in management of the risk when equipment is taken out of service for maintenance or testing per 10 CFR 50.65(a)(4).

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

The proposed amendment is similar to the amendment request submitted for the Clinton Power Station on April 26, 2004, and the approved amendments for the Braidwood and Byron Stations (Amendments 129 and 135, respectively) and the North Anna Power Station (Amendments 235 and 217 for Units 1 and 2, respectively).

5.3 Commitments

The following table identifies those actions committed to by NMPNS in this submittal. Any other statements in this submittal are provided for information purposes and are not considered to be regulatory commitments.

REGULATORY COMMITMENT	DUE DATE
Revise appropriate plant procedures to include provisions for implementing compensatory measures and configuration risk management controls when an emergency UPS inverter is removed from service for any extended Completion Time duration (greater than 24 hours and up to 7 days).	Prior to implementation of the license amendment.
Install plant modifications to allow connection of a dedicated portable power supply to provide a continuous source of power to the RCIC governor and flow controller following a Station Blackout event. This power supply must be capable of being established within 30 minutes with a probability of success greater than 0.9, as confirmed by a human factors evaluation in accordance with the guidance of NUREG/CR-6689.	Prior to implementation of the license amendment.

6.0 ENVIRONMENTAL CONSIDERATION

A review has determined that the proposed amendment would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed amendment does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure.

Accordingly, the proposed amendment meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9). Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed amendment.

ATTACHMENT 2

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP)

The current version of Technical Specification page 3.8.7-1 has been marked-up by hand to reflect the proposed change.

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Inverters—Operating

LCO 3.8.7 The Division 1 and Division 2 emergency uninterruptible power supply (UPS) inverters shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One emergency UPS inverter inoperable.	A.1	---------NOTE--------- Enter applicable Conditions and Required Actions of LCO 3.8.8, "Distribution Systems—Operating" with any 120 VAC uninterruptible panel de-energized. --------------------- Restore emergency UPS inverters to OPERABLE status.	~~24 hours~~ 7 days
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	12 hours
	AND		
	B.2	Be in MODE 4.	36 hours

ATTACHMENT 3

CHANGES TO TECHNICAL SPECIFICATION BASES PAGES

The current version of Technical Specification Bases page B 3.8.7-3 has been marked-up by hand to reflect the proposed changes. This Bases page is provided for information only and does not require NRC issuance.

BASES

APPLICABILITY (continued)

In MODES 4 and 5, the emergency UPS inverters are not required to be OPERABLE since, during these MODES, if a loss of offsite power occurred (which could result in loss of power to the uninterruptible panels until the DG starts and energizes the associated emergency buses) coincident with an accident requiring the ECCS instrumentation to perform their function, the response time of the ECCS subsystems (which will be delayed due to the loss of power to the uninterruptible panels) is not as critical.

ACTIONS

A.1

With an emergency UPS inverter inoperable, its associated 120 VAC uninterruptible panels become inoperable until they are re-energized from their Class 1E regulating transformer (maintenance transformer) or emergency UPS inverter using the internal AC source. LCO 3.8.8 addresses this action; however, pursuant to LCO 3.0.6, these actions would not be entered even if the 120 VAC uninterruptible panels were de-energized. Therefore, the ACTIONS are modified by a Note stating that ACTIONS for LCO 3.8.8 must be entered immediately. This ensures the uninterruptible panels are re-energized within 8 hours.

Required Action A.1 allows ~~24 hours~~ 7 days to fix the inoperable emergency UPS inverter and return it to service. The ~~24 hour~~ 7 day limit is based upon ~~engineering judgment~~ a risk evaluation, taking into consideration the time required to repair an inverter and the additional risk to which the plant is exposed because of the inverter inoperability. This risk has to be balanced against the risk of an immediate shutdown, along with the potential challenges to safety systems that such a shutdown might entail. When the 120 VAC uninterruptible panels are powered from their constant voltage maintenance source (or the internal AC source/rectifier with the DC source inoperable), they are relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the 120 VAC uninterruptible panels is the preferred source for powering instrumentation trip setpoint devices.

(continued)

ATTACHMENT 4

NINE MILE POINT UNIT 2 PROBABILISTIC RISK ASSESSMENT PEER REVIEW CERTIFICATION INFORMATION

The PRA peer review certification team identified the Facts and Observations (F&Os) with a significance level of "B." There were no F&Os with a significance level of "A." The significance levels for the F&Os are defined as follows:

A - Extremely important and necessary to address for ensuring the technical adequacy of the PRA, the quality of the PRA, or the quality of the PRA update process.

B - Important and necessary to address, but may be deferred until the next PRA update.

Table 1 below provides a summary of the qualifications and experience of the PRA peer review certification team members. Table 2 provides a listing of the individual F&O review items and the PRA team's initial response/resolution to each item assigned a significance level of "B". In each case, the PRA was either updated to resolve the comment or, based on the response/resolution, the item would have little or no impact on the important event sequences and equipment relative to the proposed emergency UPS inverter Completion Time. Note that some of these initial responses have subsequently been updated to reflect the availability of newer information.

TABLE 1: PRA PEER REVIEW CERTIFICATION TEAM EXPERIENCE

Team Member	EXPERIENCE SUMMARY			
	Degree	Years Experience	Years of PRA/PSA Experience	Selected PRA/PSA Projects
Lichung Pong	BS, Nuclear Engineering – Tsing Hua University MS, Nuclear Engineering – Univ. Wisconsin Ph.D. – Nuclear Engineering – Univ. Wisconsin	16	18	• Responsible for Level 1 and 2 PSA models for WNP-2 • On-Line Maintenance assessment for WNP-2 • Risk Ranking for WNP-2
Earl Page	BS, Physics MS, Nuclear Engineering	40	9	• Fermi 2 IPE Project Manager • Fermi 2 IPEEE Project Manager • On-Line Maintenance Risk Evaluation Support for Fermi 2
E. T. Burns	BS, Engineering Science – RPI MS, Nuclear Science – RPI Ph.D., Nuclear Engineering – RPI	26	21	• Technical reviewer of Level 1 IPEs for fifteen BWR plants • Manager, technical advisor, or lead engineer on many IPEs/PRAs for BWR plants • Lead engineer on several containment safety studies
Gary Smith	BS, Mechanical Engineering – Louisiana State University	Not Available	Not Available	• Project Manager for Grand Gulf Nuclear Station (GGNS) IPE • Lead analyst for GGNS Fire PRA
Rick Hill	MS, Industrial Engineering BA, Biochemistry	27	19	• Reviewer of Reactor Safety Study • Developed human reliability simulator data collection program • Project Manager for BWROG projects relative to PR
E. E. Vezey	BS, Mechanical Engineering - Texas A&M	45+	30+	• 17 years of BWR experience with GE NE • Manager of Alto Lazio PSA • SBWR Project Team

TABLE 2: SIGNIFICANT PRA CERTIFICATION FINDINGS AND OBSERVATIONS (F&O)

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element: MU Subelements: 4, 9, 13, 14	These are subelements which will not be complete until the first and subsequent update cycles are complete. Grades assigned are contingent upon follow-through by the PSA and associated groups.	B	NEG-CA-001 Rev. 4 is currently being used to prioritize PRA update/open items.
Element: MU Subelement: 5	In addressing plant specific failure events during the PS update, the UPS event which occurred at NMP should be included in the basic events.	B	As part of the PRA update, all initiating events at NMP2, including the UPS event were evaluated and included in the PRA (Section 5.3.1). The impact of the UPS event of 8/13/91 was basically a loss of feedwater subsequent to a plant trip. Based on this event alone, the unavailability of feedwater is presently judged to be optimistic because it does not account for this event. However, the loss of feedwater initiating event increased from 0.05 (IPE) to 0.14 in the PRA update, which is judged to reasonably capture this event. The unavailability of feedwater, given it was not the initiator, was not increased because of the initiator frequency and the fact that measures have been taken to preclude the UPS event from recurring.
Element: MU Subelement: 6	There is in place a good system of archiving the PSA model and other related documents. This system should be well documented to insure that this information is assessable in the event of discontinuity in program management or other upset.	B	Tier 1 and 2 documentation for the PRA update are available both in hard copy with signatures and electronically. The documentation also summarizes changes from the original IPE. Background documentation (IPE and IPEEE and supporting information) is archived in files and on CD ROM.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element IE Subelement 7	1. Should probably examine possible inclusion of BOC (Break Outside Containment) as an initiator in light of its potential contribution to early-high release, not just CDF. 2. Also might consider multiple stuck open relief valves, as an initiator. 3. Should also examine the assumption of not analyzing sequences subsequent to a manual shutdown or manual scram. While these are usually "controlled" shutdowns, systems and operators are still challenged. In some cases, a manual scram would not be "completely controlled" depending on the need for the scram.	B	1. PRA update Section 5.3.3 was improved to explain why the frequency of Core Damage and LERF are low. 2. The frequency of multiple SRVs opening is on the same order of magnitude as Large LOCA with less severe challenges to the containment. PRA update Section 5.3.3 addresses this subject. 3. Manual shutdown events are now explicitly modeled in the PRA update (see PRA Section 5.3.1).
Element IE Subelement 8	The scope of LERs and shutdown history is described; events are shown in Tables A-3 and A-4 (Tier 2). However, it is not clear why the transformer/UPS event of 8/13/91 was not included in the initiator data base.	B	The UPS event occurred after the IPE cutoff date. However, the event is explicitly included in the PRA update (see Section 5.3.1).

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element IE Subelement 13	System 26 (P. 3.2.1.26-1 of IPE) The LOSP frequency and the recovery are intimately tied together. The NUREG-1032 recovery curves can be applied each on its specific frequencies. However, it appears that the NUREG-1032 weighted recovery curve was used and applied to the LOSP frequency which was based solely on grid and plant centered data. This appears to be optimistic relative to the NUREG-1032 assertions relative to severe weather because the magnitude and sample size of the plant specific data does not preclude a non-negligible weather component estimated after the guidance stipulated in NUREG-1032. It is advocated by the Certification team that the data only supports updating the plant centered data from 0.087/yr to 0.04/yr. Therefore, the weighted average of recovery should be recalculated coupling the new IE frequency which should include a 0.01 frequency for severe weather with the corresponding NUREG-1032 recovery curves.	B	Based on the PRA update, LOSP frequency increased from 0.04 to 0.11 based on plant specific data. Then, NUREG-1032 is used for recovery and includes weather events. The writeup was also improved during the PRA update (PRA Section 4.2.26 and 3.1)
Element IE Subelement 16	LOSP frequency development should not preclude non-negligible severe weather component. Its 1 in 100 year value can't be precluded based on a short generating history. It should be added and included more appropriately in the recovery value.	B	LOSP recovery and use of NUREG-1032 has always properly accounted for severe weather. This was rectified during the PRA update and write-up was improved.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element AS Subelement 5	The evaluation of accident sequence response using RCIC can be strongly influenced by the plant specific feature at NMP-2 of the Dikkers SRVs. The Dikkers SRVs have characteristics associated with them that result in RPV depressurization to very low pressures when the EOP direction is followed to open all ADS SRVs. Following the emergency depressurization directions results in the RPV pressure reduced to well below the pressure required for RCIC operation whether or not the low pressure trip is bypassed. This effect is to make RCIC unavailable whenever emergency depressurization is directed by the EOPs.	B	SBO procedure N2-SOP-01 Rev. 4 Cautions the Operators that "operating with RPV pressure less than 200 psig can jeopardize RCIC availability." Also, most recent EOPs (1/1/99) provide new direction (EOP-6, Attachment 29) so that depressurization does not necessarily make RCIC unavailable. Also, MAAP calculations indicate that it takes at least 4-6 hours without containment heat removal (per EOPs and operator training, RPV pressure is maintained below HCTL and other containment limits) before eventual emergency depressurization may occur. Since the SBO analysis ends at 8 hours this is not an important issue.
Element AS Subelement 5	Based on Calculation EC-129, the Division I battery 2BYS*BAT2A Type NCN-35 is able to supply loads during SBO for six hours. In this calculation, the loads not required during SBO event are assumed to be shed within two hours. The current assumption is that the station battery could last for 10 hours. Therefore, it is recommended that the event tree analyses for the SBO scenario be revised.	B	The SBO model has been revised as part of the PRA update. Recovery is now only allowed out to 8 hours given successful DC load shedding (based on latest analysis). This has a minor impact because there was very little credit in the original analysis beyond 8 hours anyway (See Section 3.2.1.3).
Element AS Subelement 6	SBO There is a revised SBO evaluation for NMP2 from GE which indicates that there are a number of new constraints on the ability to cope with an SBO. These include reduced battery life, requirements to depressurize within 4 hours, and higher RCIC room temperatures. These considerations are judged to adversely impact the SBO accident sequence evaluation in the PSA.	B	The latest GE analysis and procedures were reviewed and considered in the PRA update and the SBO model was revised extensively (see previous observation). The SBO risk was reduced due to modeling changes (mostly due to changes in procedures to use HPCS to supply Div I or II AC). The latest procedures and training incorporated insights from the IPE. Since LOSP frequency has increased based on plant specific data, the overall effect of the update was not a reduction in risk.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element AS Subelement 11	ROOM COOLING The treatment of room cooling for RHR and LPCS operability is described in a confusing and conflicting manner in the IPE documentation. For example, the room cooling requirement for RHR is not clearly delineated in the dependency matrix and the method of room cooling treatment for loss of service water cases is highly dependent in the model on the operating action to open doors. This is not currently proceduralized and therefore should not be credited. There may also be calculations with GOTHIC that could justify not requiring an active room cooling system. These issues need to be clarified to ensure that system importances for applications are accurately reflected.	B	Both the confusing documentation and the modeling of room cooling have been corrected in the PRA update. Gothic calculations (SAS-PRA2-S-RHS-CALC, June 1998) show that the limiting room (RHR B room) is marginal and realistically does not require room cooling. Still, the PRA model conservatively fails RHR rooms A and B if room cooling fails. The LPCS and LPCI C rooms clearly do not require room cooling and this dependency is no longer included. The RHR A & B failures although conservative do not impact the PRA results.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element AS Subelement 7	DFP The diesel fire pump alignment under SBO when essential lighting has been shed appears to be a difficult process. There is questionable evidence that the alignment can be performed and the LPCI valve opened under SBO conditions.	B	The present model only allows a 0.5 probability of success (0.2 operator action failure). The most recent EOPs ensure that the DFP will be aligned early (level below scram set point and stops in the EOPs have been removed); the operators will not wait. SBO model only allows DFP success if RCIC was successful for 2 hours. The operators practice the physical alignment and the LPCI MOVs are accessible. This has not been practiced in a SBO condition where the operators have to use flashlights. However, given that this would be done by sending operations personnel out in pairs, the above EOP changes, and timing in the SBO model, a 0.2 probability of failure is judged reasonable if not conservative. We may pursue taking more credit for the operator in the future. A separate open item was whether the DFP can protect the core 2 hours after event initiation (0.3 failure probability). Preliminary MAAP calculations indicate that a diesel fire pump with 1 of 2 injection paths is marginal. Therefore, the 0.5 S1 failure probability may not be conservative, but is still considered reasonable given our present state of knowledge. This will be considered further relative to risk management and future updates.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element AS Subelement 10	TRACEABILITY The traceability of individual elements of the model are difficult in some cases. The miscalibration of the low pressure permissives on the LPCI AND LPCS lines are identified as possible pre-initiator HEPs, but their basic event is: • not identified in the IPE discussion of the HEP • does not have a calculation to support the quantification of the HEP referenced in the IPE • is not included in the fault tree for the low pressure injection systems • is not included in the cutsets for the respective top events • is included in the ECCS initiation logic	B	The PRA update improves the documentation. Section 5.2 identifies HRA event ZEC01 and basic event ISCZECMISCALIB01 as included in top event ECV which models common cause failure of all ECCS low pressure injection paths. When ECV fails, all low pressure injection paths fail in the PRA model.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element AS Subelement 5	SBO The accident sequence evaluation for SBO needs to be re-evaluated based on the revised SBO report which substantially shortened the available time for coping from 19 hours used in the Rev 1 of the SBO calculation and in turn used as a basis for the IPE to 4 hours in Rev 2 of the SBO report. This is believed to have a major impact on the quantification of dominant core damage sequences. Because a realistic assessment of the Rev 1 results was used in the original IPE model, the quantified impact of Rev 2 is expected to be not large. This shows good judgment in the use of the original optimistic Rev 1 SBO report results.	B	The PRA update includes a major revision to the SBO model. As discussed in response to other observations, the model only goes to 8 hours (e.g., no credit is given to recovery beyond 8 hours) and is based on latest analysis and procedures. There was very little credit in the original model beyond 8 hours. Refer to PRA Section 3.2.1.1.
Element AS Subelement 13	The impact of load shedding assumptions on the PSA should be re-evaluated and their results documented.	B	The PRA update includes a major revision to the SBO model based on latest procedures and analysis. Although the HRA has not been redone, the procedures are consistent and in some instances exceed the IPE assumptions. The model conservatively assumes core damage occurs early at 2 hours if load shedding fails.
Element AS Subelement 10	DEPENDENCIES AND LOW PRESSURE PERMISSIVE The HRA discussion identifies the injection valve low pressure permissive as a potential CCF probability due to miscalibration. However, in the low pressure injection systems there is no identification of this CCF failure mode.	B	In the PRA update, miscalibration is included in top event ECV. Failure of ECV fails LPCS and LPCI injection paths. Success criteria will not allow low pressure makeup through these paths from any source. See PRA Sections 4.2.4 and 3.2.1 event tree rules for SUP4, TR1, etc. No detailed calculation has been developed for this miscalibration HRA; the evaluation is described in PRA Section 5.2. See also the response to Element HR, Subelement 6.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
	This failure mode does not appear to be discussed in any other IPE section. The basic event appears to have been put in the E1, E2, E3 ECCS initiation logic which is assumed to be able to be backed up by manual actuation if auto initiation fails. IA and IB and LS are not affected by this failure if ME is successful. There may also be some additional HEP that could be included to address the question of locally opening the injection valve and bypassing the low pressure permissive by turning the valve hand wheel. No HRA is performed to support this action. There does not appear to have been a clear definition of what the HEP was, where it was calculated, or what logic model it applies to. The impact is judged to be small but it cannot be readily confirmed because the dependencies associated with the failure of this permissive could adversely impact LPCI, LPCS, SW X-TIE, AND THE DIESEL FIRE PUMP. Ensure the HEP for the low RPV pressure permissive is: • described in the LP injection systems • quantified in a calculation • treated among "tops" so that the dependency is accurately reflected		

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element AS Subelement 5	CONTAINMENT VENT The EOPs and the EOP-6 specific attachment for venting taken together represent the written basis for operator response to challenges to high containment pressure. However, the vent that is allowed by these is assessed in the HRA to have a 1.0 failure probability. Despite this, the model appears to use a more optimistic HEP that was developed including assumptions regarding procedural modifications. Recent emergency drill experience indicates that the operating staff in conjunction with the TSC could decide under certain conditions to vent the containment without requiring the extensive alignment of the "hard piped" system.	B	Major improvements have occurred since the IPE. Latest improved EOPs have removed stops such that operators will not wait for the high pressure condition that requires venting. This was confirmed with Operations. In other words, with the knowledge of venting alignment difficulties and the improved EOPs, there is a high likelihood of success. Containment venting has been addressed in drills and training and as part of the SAM process. Present EOPs and supporting procedures were found to provide adequate flexibility and to address support states. The SAM process and TSC guidance will also help. The present analysis (same as IPE) is judged reasonable to conservative.
Element DA Subelement 7	If there is a sufficient experience base, recommend replacement of maintenance unavailability data with plant specific data.	B	Current plant specific maintenance unavailability is being used in the PRA update (Section 5.1).
Element DA Subelement 8	Numerical results for common cause failure of SRVs to depressurize appear to be quite low.	B	NRC/INEL common cause data parameters are used in the PRA update and judged to be reasonable if not conservative (see Section 5.1.3).

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element DA Subelement 9	<u>SRV/SOLENOID CCF</u> The SRV data and the associated solenoids can be expected to have a CCF term or terms. The NMP2 model has an extensive degree of CCF terms. The IPE currently uses ~ 1E-6 as the CCF for all valves and 1E-5 for the sum of all multiple hardware failures of a CCF nature. This may be optimistic. However, a simplistic CCF approach using generic SRV data results in estimating the CCF probability at 4E-4. This estimate should be checked against the design and possibility of a common cause failure.	B	NRC/INEL common cause data parameters are used in the PRA update for SRVs, SOVs, check valves, and are judged to be reasonable, if not conservative (see Section 5.1.3). The simplistic model and values suggested above do not apply at NMP2; detailed common cause modeling is utilized. Global common cause (easiest comparison to simplistic approach) in the NMP model is ~2E-5 for all SRVs and ~2E-5 for all SOVs. Thus, the simplistic approach appears to be conservative by an order of magnitude.
Element DA Subelement 15	The probability of a SORV conditional on its need to open for various transient initiators is not modeled. Transients with SORV are terminated and believed to be accounted for in the IORV/Small LOCA tree. This is adequate if the initiating event frequency for IORV adequately includes the SORV conditional probability which may change for sensitivity studies, applications, and updated transient data.	B	The IORV initiator was recalculated based on plant specific data (see Sections 5.3.1 and 5.3.3).
Element DA Subelement 15	The value of and the rationale for the diesel mission time is not documented. The only source of the value was a RISKMAN file. This is a fairly highly visibility and controversial PSA issue.	B	Systems analysis Tier 1 (Section 4.2.6) and Tier 2 identify the fact that diesel mission time is 6 hours. The basis is that the SBO model only goes to 8 hours and recovery time depends on when the diesel fails (e.g., time to core uncovery after 6 hours of EDG success is much longer). Since these conservatisms are not accounted for in the SBO model, 6 hours was chosen as a reasonable, but conservative time.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element DA Subelement 15	RPS (duplicate of SY-19) The scram system description and the basis for the point estimate calculation for mechanical and electrical common cause failure are incomplete. NUREG-0460 is referenced for the estimated failure probabilities, but this document does not justify the 4.3E-6 mechanical common cause failure probability. The basis for the cited value requires that the scram air header have a low pressure scram signal as input to the RPS. The system description does not define this and therefore the cited conditional probabilities do not apply.	B	INEEL/EXT-98-00670, October 1998, "General Electric Reactor Protection System Unavailability, 1998 – 1995 (draft 2)" suggests an unavailability estimate of 3.8E-6/year. The present NMP2 analysis is judged to be conservative.
Element HR Subelement 5	The IPE does not provide any real insight into a systematic process being followed to conclude that pre-initiator HIs could be assumed to be subsumed into maintenance unavailabilities.	B	Pre-initiators were assessed for each system during the IPE and PRA update. They were not assumed to be subsumed into maintenance unavailabilities. The revised evaluation is documented in the Systems Analysis and included in the PRA model summarized in Table 5.2-1.
Element HR Subelement 6	The source and analysis behind the selection of 1.0E-5 for common cause mis-calibration of instrumentation is not adequate. A more complete explanation and /or analysis should be provided in the update of the IPE.	B	The likelihood of miscalibration is low as documented in Section 5.2 of the PRA update. The ~1E-5 value is similar to NUREG results.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element HR Subelement 10	The tier 2 HRA document appears to be missing the following: HHU21—Stop RPV depressurization before RCIC stalls. This HEP is not evaluated in the HRA document even though it references another HEP. It uses a value of 1E-2 as the failure probability even though there is no procedure to deal with the Dikkers SRV effect of allowing depressurization to below the RCIC operability point of 50 to 60 psig.	B	This action is no longer included in the model because depressurization is not expected to occur during the SBO time window of 8 hours. Also, the procedure (N2-SOP-01) cautions operators with regard to depressurizing too low and the latest EOPs contain guidance relative to not having to depressurize with RCIC running (EOP-6 Attachment 29). See also the response to Element AS, Subelement 5.
Element HR Subelement 10	SBO HEPs for SBO may need to be re-evaluated using the directions in SOP-01 and SOP-02. These directions may alter the assessed HEPs. Neither SOP-01 nor SOP-02 specify pre-alignment of the DFP for injection prior to reducing the essential lighting. This is judged to result in a substantial degradation in DFP successful alignment probability.	B	The operators are in the EOPs, which address the DFP, as well as SOPs during SBO. The latest EOPs ensure that DFP will be aligned early without hesitation. This has been confirmed with Operations. In addition, DFP alignments are likely to be accomplished before reducing essential lighting loads (DC load shed). The original HRA analysis is considered conservative. (See also the response to the Element AS, Subelement 7).

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element HR Subelement 11	DFP The HRA appears to be performed assuming that the power to MOV 24A is available to support opening it during the assumed alignment for RPV injection. EOP-6 Attachment 6 does not identify how the valves are to be opened or the difficulty involved in opening the valves under different conditions such as SBO or loss of service water. The HRA apparently assumes the following optimistic assumptions regarding DFP alignment under SBO conditions: • no load shed of essential lighting which is specified in SOP 01 • all valves are accessible, but no information provided to justify this • all valves can be turned by the crew, but no information provided • sufficient crew is on-site to carry out the actions • power is available to MOV 24A These are all judged to be optimistic, and the assumption that power is available to MOV 24A is clearly incorrect in the way the DFP is used in the PSA model.	B	Power is not assumed available during SBO. An operator must open MOV 24A locally. All valves can be turned by the crew. Confirmed with Operations that if the valve fails to open or can not be opened due to no AC power, it is understood that it will be opened locally. See also the responses to Element AS, Subelement 7, and Element HR, Subelement 10.
Element HR Subelement 12	FW FLOW CONTROL DURING ATWS Re-establishing feedwater between 25 sec after feedwater runback ("lockout" time) and 83 sec when Level 1 is passed isolating the condenser hotwell due to MSIV closure appears to be given too much credit at 0.5.	B	Re-establishing feedwater does not have to occur in the time frame suggested and it was judged that there was some chance. NMP does not believe in using 1.0 when there is an opportunity for success (based on HRA and interviews). We judge that the 0.5 value is appropriate.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element HR Subelement 16	The HRA analyst used a "cause based" analysis procedure (EPRI-TR-100259) for developing HHA1. This is a stress related event and the EPRI procedure is judged not to be effective in differentiating between stress and non-stress sequences. Therefore this HEP may be lower than the sequence can justify.	B	There are several hours to perform this local action. The TSC could also perform the action. NMP considers the value to be conservative.
Element HR Subelement 16	LPCI/LPCS FLOW CONTROL UNDER ATWS EOP-6 Throttle ECCS Attachment 3 This appears difficult to implement and is not the procedure evaluated as part of the HRA for this action.	B	This action is performed after emergency depressurization and the EOPs utilize LPCI A and B as the preferred ECCS trains. Throttling is available in the control room from these trains, which makes the task much easier than having to apply EOP-6 Attachment 3. Even if EOP-6 Attachment 3 is needed, it is straight forward and is performed in the control building. A re-evaluated HEP is judged unnecessary at this time.
Element HR Subelement 23	HHMA1: MA & MB (Loss of SW) This action is to open LPCI room doors to assure room cooling. The HRA assumes a procedure is in place. However, a procedure could not be identified—neither EOP-6 nor SOP-01 specify opening LPCI doors or MCC doors for room cooling. The HRA assumes a procedure exists and uses a value of 0.1 conditional failure probability (90% success).	B	Operator action has been removed from the model. Loss of room cooling fails RHR A & B with no credit for operators. This is conservative based on a Gothic calculation.
Element HR Subelement 28	The HEP, HHU-21, is an action identified in Table 3.3.3-1 as "Stop depressurization before RCIC stalls." There is no EOP for this action: therefore, the analysis (per the Table "see HHOA1") is not a valid analysis since the timing, stress and steps to perform are not identified.	B	This has been removed from the model because the updated model stops at 8 hours before containment conditions becomes an issue. Also, see response to Element AS, Subelement 5, and Element HR, Subelement 10.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element DE Subelement 4	It appears that the dependency matrix was constructed with plant design basis in mind, rather than the realistic (as modeled) basis for the PRA. This may be somewhat confusing for future users. Example: Noted dependency of RHR on normal AC, TBCLC and Service Water for pump seal cooling. System discussion notes assumption that seal cooling is not needed. Component Block Description tables (in system portion of the report) are good in that they define failure mode, initial state, actuated state, support system and state on loss of support. The matrix should relate to this better.	B	The dependency matrix was intended to address all dependencies that the engineers could identify during the PRA development without requiring consideration as to whether they were needed in the model. Note that seal cooling during shutdown cooling is a dependency but shutdown cooling has not yet been added to the PRA. The Systems Analysis (PRA Section 4.2) identifies the dependencies that are modeled and why some may not be modeled.
Element DE Subelement 5	It is not apparent that pre-accident human actions are incorporated in the modeling (common cause miscalibration or failure to restore from maintenance).	B	This was considered again during the systems analysis task during the PRA update. It is better documented in the systems analysis (Section 4.2). Several misalignment pre-initiator events were added to the model (Table 5.2-1). Nothing significant was found or added to the model.
Element DE Subelement 9	The evaluations are simplistic, e.g., room heat-up evaluations, zebra muscles, etc. Each evaluation should be supported by quantitative analysis where appropriate rather than being a qualitative evaluation.	B	This was considered during the PRA update with minor changes made (failure over a 24 hour mission time with the design and programs is not judged likely). No cost-benefit justification for further quantitative analysis could be made given the present modeling, including common, etc. Loss of lake intake to service water was added to the PRA as an initiating event (LKX) to provide additional completeness.
Element DE Subelement 9	The flooding screening criteria that states floods which do not cause initiating events and impact an important system should be eliminated. Such criteria are very difficult to justify. A broader set of floods should be considered.	B	Section 3.1.6 was clarified during the PRA update to say that generally these types of failures are required in order to be important, which NMP still believes. The original write-up implied that this was a basis for modeling. Note that there are still some floods that were screened out that could be modeled in the future; this will be considered as a future update.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element QU Subelement 8	The following assumptions are made in the analysis: • In a loss of Div. I Emergency AC power event, it is assumed that the Div. II charger would not be able to maintain the load. • During an SBO event, if RCIC is successful for the first 2 hours, there is a probability (0.1, assumption) that the operator would improperly depressurize the vessel and cause the unavailability of RCIC. Although the procedure (SBO-6) reminds the operating staff to use caution, no guidance is provided. • Discussion with a shift supervisor during the certification peer review indicated that if directed to emergency depressurize by the EOPs, RCIC availability would not be a reason to stop the depressurization.	B	• The charger is credited in the PRA update as suggested. • The 0.1 probability event has been removed in the PRA update as not likely during the first 4 to 8 hours. • EOP and SOP procedure changes improve the depressurization concern. See responses to Element AS, Subelement 5, and Element HR, Subelement 10.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element QU Subelement 18	There are several operator actions that are credited in the analysis but the procedure guidance is either not in place or not clear. For example: • venting the containment • opening the doors to provide room cooling • depressurization of the vessel when makeup is provided by RCIC during SBO.	B	The room heat-up calculation has been completed and model revised accordingly. The updated model is based on procedures, training, and operator interviews. Note that there are some actions that are not explicit in the procedures, but are obvious and confirmed by interviews with Operations and Training. For example, if an MOV does not open or close, the operators would send someone locally (e.g., HA01).
Element SY Subelement 7	Injection system piping "keep filled" systems are not modeled because they are not considered to cause failure if not functional. The treatment of the keep fill system is a strong potential variable identified among different plants regarding its treatment in the PSA. The treatment varies from: • Not included in the model to • Included in the model and if unavailable causes the system to be unavailable (i.e., operators would not use the system if injection pipe known not to be full) This variation is extremely different. There can be some plant specific design or procedural differences that affect this treatment.	B	The systems analysis documentation (e.g., PRA Section 4.2.1.11) was improved to explain why explicit modeling of the keep fill system is not required.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element SY Subelement 7	LOSP load shedding diesel start sequence and reloading not modeled.	B	This was considered during the PRA update. Failure of diesel generator load sequencing is assumed to be included in the basic events for EDG start, MOV supply operation, and circuit breaker demand. The failure of the load sequencing is considered a small contributor in comparison to the other failure modes (PRA Section 4.2.6.11).
Element SY Subelement 8	IPE documentation indicates that mis-calibration of ECCS pressure permissive is modeled. Such an event could not be identified in the fault trees for E1, E2, A1 or 1B.	B	This has always been in the IPE and the PRA update as basic event ISCZECMISCALIB01 (see PRA Sections 4.2.4 and 5.2).
Element SY Subelement 8	IPE indicates that there is potential for human induced common cause failure for SLCB (failure to restore). It is assessed to be 3E-3 (or 3E-4 after some procedure changes). However, fault tree SL includes events "Valves Misaligned after Testing—Operator Error" and "Isolation Valve Misaligned After Quarterly Testing." Only the first shows up in the SL cutsets and then with a probability of 1E-5.	B	The documentation and fault tree has been revised in the PRA update. A single event is used to represent unavailability of SLCS due to misalignment.
Element SY Subelement 10	There is no common cause event for ECCS suction (suppression pool) strainer plugging.	B	Top event ST has been added to the PRA which models common cause ECCS Suppression Pool suction strainer plugging (Section 4.2.1 and event tree SUP4 in Section 3.2.1.1).

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element SY Subelements 10 & 12	Support system requirements appear to be accounted for in the model but the supporting documentation is confusing and not clear in some cases. Example: HVAC requirements for RHR pumps. Indicates that pumps would fail with loss of cooling (~ 5 hrs.) but do not model because loss of HVAC to MCC area is more restrictive because it fails two injection paths. Discussion for MCC area coolers said that cooling would not be a problem until 9 hours (and then only if RHR and LPCS had not started by then). Therefore, it was not important. This implies that HVAC for MCC areas is not modeled when it actually is.	B	Documentation has been clarified and the modeling revisions were made as part of PRA update (Section 4.2.11).
Element SY Subelement 17	RCIC may have temperature trips on high Main Steam Tunnel and RHR room temperature. These trips do not appear to be modeled in the RCIC system analysis. These trips need to be included in the RCIC model to account for common failures causing both MSIV closure and RCIC failure. A plant-specific room heatup calculation should be performed to insure that this is not a special initiator.	B	High area temperature trips (RHR A and B rooms and RCIC) have been added to the RCIC model in the PRA update (Section 4.2.1.2).

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element SY **Subelement 26**	<u>SRV DESCRIPTION</u> The description of the SRV capability and its characteristics are not provided. The Dikkers characteristics of importance to include in the description are the following: • nitrogen pressure required to open SRVs under different containment conditions • Lowest RPV pressure that emergency depressurization will bring the RPV to • leakage characteristics of the nitrogen supply • duration of the nitrogen supply • operator actions necessary to provide SRV capability • accident response • qualification temperatures and pressures of the SRV and solenoids • treatment of relief valves on the pneumatic lines	B	The original IPE and the PRA correctly account for the Dikkers SRVs. In fact, the potential for depressurizing all the way to ~0 psi was a concern identified in the original IPE as part of the SBO analysis. The EOPs now address this potential cause for making RCIC unnecessarily unavailable. PRA Section 4.2.1.13 discusses the model, timing of nitrogen supply, etc. It was not deemed necessary to have a "Dikkers SRV" discussion, but this may be considered if necessary for specific applications. Relief valves on pneumatic lines have been neglected as insignificant contributors.
Element SY **Subelement 26**	<u>DIESEL FIRE PUMP</u> The flow rate and the pressure capability of the DFP for RPV injection would be useful. Specifically, a calculation that identifies whether the DFP can provide adequate core cooling and under what containment and RPV conditions.	B	Preliminary calculations and MAAP analysis have been conducted which indicate that DFP is marginal in protecting the core. The 0.5 probability of success once thought to be conservative is considered reasonable until further analyses are conducted.

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element SY Subelement 26	Identify the low pressure permissive logic and its configuration for all low pressure injection valves. Also define how this low pressure permissive is included in the evaluation of the service water cross tie injection and the DFP injection evaluation. Specifically, is the low pressure permissive miscalibration failure mode included in all injection modes using SW and the DFP.	B	Non-SBO Model Common cause miscalibration is now in top event ECV in the PRA update. Failure of ECV guarantees failure of all ECCS injection paths including top events IA and IB (RHR A and B injection paths). If IA and IB fail (e.g., due to ECV), then fire water and service water crosstie are also failed in the model since they depend on IA and IB. This is all documented in the RISKMAN PRA model. SBO-Model ECV is neglected as an insignificant contributor to DFP failure (ECV failure << DFP).
Element TH Subselement 4	Success Criteria related items that could use better documentation or model changes in the update include the following: • room cooling treatment for RHR and MCC rooms • DFP alignment success probability when performed under SBO conditions involving load shedding of all essential lighting • RCIC and DFP success given revised GE SBO report • RCIC success following Emergency Depressurization • Depressurization requirement for Medium LOCA with RCIC initially available (conservative assumption)	B	• Room cooling treatment has been clarified and model changed (Section 4.2.11). • DFP credit has not been changed. Preliminary analysis indicates that the model is reasonable. • SBO analysis and model have been updated per the latest GE report (Section 3.2.1.3). • Emergency depressurization does not occur with RCIC success in SBO for at least 4-6 hours (Sections 3.2.1.3 and 3.3). • Model revised such that MLOCA and RCIC success lead to emergency depressurization success (Sections 3.2.1.5 and 3.3).

Element / Sub-Element	PRA Certification F&O	Level of Significance	Risk Impact - Response/Resolution
Element TH Subelement 10	ROOM HEAT-UP There is an effective discussion of the room heatup calculations that addresses various rooms in the plant relative to room cooling requirements. The dependency matrices and the documented discussion relative to system capability under loss of room cooling may not always be consistent. In addition, there may be more recent information to support more realistic modeling of the system capability under loss of room cooling.	B	Documentation, calculations and models, including PRA Section 4.2.11 and the event tree models in Section 3.2.1, have been updated. See response to Element IE, Subelement 3.
Element TH Subelement 12	There is very little discussion of the thermal hydraulic calculations that are used in the various aspects of the model.	B	MAAP models have been updated as well as the Tier 1 and 2 documentation in Sections 3.3 and 3.4.

ATTACHMENT 5

NRC REVIEW COMMENTS SUMMARY

The NRC SERs for the NMP2 IPE and IPEEE were reviewed and specific comments were identified and assigned as individual items for the NMP2 PRA update in 1998. Provided in the table below is a listing of each comment, along with the NMPNS PRA team response/resolution.

NRC Comments on IPE and IPEEE		
Item[1]	**Comments**	**Response/Disposition**
IPE-Letter Pages 2 & 3	Description of IPE results and unique features.	Description is reasonably accurate for the IPE. A description of the present PRA results will be different. For example, the statement "No credit is taken for recovery..... over 20 to 30 hour .... containment failure" is no longer true in the PRA; improvements in recovery have been incorporated.
IPE-Letter Page 2	NMPC developing procedures to prevent RCIC trip under loss of service water.	This has not been incorporated into procedures, but is an obvious action (required within 2 hours in SBO procedure SOP-1) and TSC guidance (monitoring area temperatures, etc.) is expected to identify this obvious action. Per the NMP2 Station Blackout Bases Document, RCIC room heatup calculations assume the door is closed, but it is open to allow lower room temperatures.
IPE Section 6.2 identifies NMPC plans credited in IPE. If not implemented NMPC should revise IPE to reflect as-built, as-operated. Need not submit to NRC, but retain records for future.	To install valves in SGTS to increase reliability of containment venting.	Subsequent to the IPE, this valve installation modification was cancelled as not being cost-beneficial. As a result, training and procedure changes were pursued to assure that human reliability credited in IPE is reasonable. Several drills and training sessions addressed this aspect of the EOPs, including the last resort option of SGTS Bldg blowout. The latest EOPs have removed stops in the procedure; now the operators continue in the PC-P leg of procedure N2-EOP-PC and anticipate containment venting alignment. In addition, TSC guidance and resources will improve the obvious need to anticipate this alignment and provide resources. Although all these improvements in procedures, training, resources, and etc. are judged to support or improve the HRA value, the IPE values are still being used until a re-evaluation of this HRA is performed.
	Develop procedures to enhance Aux Bay room cooling during loss of service water.	No procedure was developed and credit for operator actions has been removed from the IPE model. Gothic calculation (SAS-PRA2-S-RHS-CALC, June 1998) shows that the limiting room (RHR B room) is marginal and realistically does not require room cooling. Still, the PRA model conservatively fails RHR rooms A and B if room cooling fails. The LPCS and LPCI C rooms clearly do not require room cooling and this dependency is no longer included. The RHR A and B failures although conservative do not impact the PRA results.
	Enhance SBO procedures.	SBO procedures were not available at the time of the IPE. Subsequent to the IPE, SBO procedures (SOP-1, 2 and 3) were developed and support the IPE assumptions.

NRC Comments on IPE and IPEEE		
Item[1]	**Comments**	**Response/Disposition**
	Provide additional internal flood guidance.	Additional guidance includes opening doors from outside that will remove water from the building. Guidance to isolate the flood is also included (see Alarm Response Procedure N2-ARP-01, Rev. 00 pages 1305-1307).
	Improve test & maintenance procedures to reduce the likelihood of ISLOCA.	Procedure change has not been made nor is it judged necessary. The PRA (Section 5.3.3) now incorporates the low probability of a MOV being opened during testing & maintenance without procedure improvements; this contributor is an insignificant risk contributor. On-line risk monitoring ensures that the unlikely coincident activities needed to initiate this event are identified in advance (e.g., PRA model should be conservative).
IPEEE-SE Page 2	0.5g HCLPF for 24 hrs does not meet EPRI SMA guidance.	Clarification: The 0.5g HCLPF is for 72 hours (see comments on TE below).
IPEEE-SE Page 6	Vulnerability definition not provided.	The fact that no vulnerability definition is provided does not provide a problem for NRC since the risk is obviously acceptable based on the NMP evaluation. See PRA Section 10 relative to risk management.
IPEEE-SE Page 6	Plant improvements needed.	Seismic mounting of rack, cabinet and hoist assembly The plant modifications for the seismic mounting described have been made (IPEEE page 7-2). CR Fire EOP-RPV is now retained at the remote shutdown panels. The control room fire risk in the PRA is judged to be conservative and is not dominating. There are no plans to add explicit TSC guidance or additional training.
IPEEE-TE Page vii	No freeze date.	This comment refers to a data freeze date beyond which additional data would not be considered. A date for data analysis for this PRA was implemented; however, other aspects of the PRA were allowed to change as appropriate to final sign-off.
IPEEE-TE Page ix Page 30	Tornado screening incomplete.	No action to be taken. NRC's analysis also shows that risk from high winds is low and can be screened.
IPEEE-TE Page ix, xii Pages 31-34, 44	External flood bounding analyses appear flawed and incomplete.	TE agrees that external flooding can be screened based on SRP compliance, but disagrees with NMP simplistic bounding argument. It is very difficult to estimate the risk from floods and there are numerous combinations of events that must be considered. It is NMP's position that a detailed analysis, considering plant procedures and timing, would lead to a low risk on the order of 1E-6/yr. Since there is very little that can be done cost effectively to reduce this risk further, no additional analyses are planned.

NRC Comments on IPE and IPEEE		
Item[1]	**Comments**	**Response/Disposition**
IPEEE-TE Pages x, xii Pages 7, 9, 10, 11, 41, 43	0.5g HCLPF for 24 hrs and not meeting EPRI SMA guideline for success reliability.	Clarification: The 0.5g HCLPF is for 72 hours. Only when using success path reliability guidelines of EPRI SMA does a 0.23 HCLPF result unless we credit equipment not in analysis scope. EPRI SMA is only guidance and justification for deviating is provided by the PRA analysis. This was shown to be non-risk significant by NMP and TE seems to agree. Also, note that the NMP PRA success criteria are for 24 hours not 72 hours, including external events.
IPEEE-TE Page x, xii Page 2, 24, 28, 44	Additional equipment failures due to smoke and combustibles not adequately addressed.	NMP does not know of any analyses to address this issue. If new analyses become available NMP will consider this further.
IPEEE-TE Page x Pages 24, 28, 44	No fire barrier failure rates in analysis, cross zone fire analysis.	Because of limited combustibles, limited active barriers, reliable detection and suppression, the screening and analysis is judged conservative. Scenarios where fire barriers failed were judged to be very low risk contributors. NMPC agrees that documentation of these judgments could be improved. The risk ranking of fire barriers will likely require this analysis improvement.
IPEEE-TE Page x Page 31	GI-103: No details of re-evaluation in submittal.	The FSAR re-evaluation was not repeated in submittal and there is no plan to do this as it adds no value.
IPEEE-TE Page xi Page 45	Plant improvements identified during walk down.	The storage rack near the RCIC motor-operated valves has been secured (IPEEE page 7-2).
IPEEE-TE Page xii Pages 2, 26, 43	Operator error rates for control room fires are highly optimistic, etc.	The most reliable operator action is used for only those fire scenarios where the control room remains habitable and equipment needed for immediate plant control is operating successfully. Also see response to IPEEE RAI II.1.
IPEEE-TE Page xii Pages 2, 19, 43	Heat release rate for cabinet fire not representative.	No action to be taken as it does not appear to impact the analysis conclusions.
IPEEE-TE Pages 2, 27	Seismic fires due to weakly anchored cabinets not addressed.	There are no known weakly anchored electrical cabinets at NMP2.
IPEEE-TE Page 7	Stuck open SRV and Large LOCA not addressed.	A stuck open SRV with RCIC success guarantees successful RPV isolation (nitrogen is not needed) and allows low pressure injection success. Therefore, the stuck open SRV event improves the number and reliability of success paths and is an insignificant risk contributor. Also, medium and large LOCAs due to pipe breaks are incorporated in the 0.5g HCLPF fragility in the PRA model.

NRC Comments on IPE and IPEEE		
Item[1]	Comments	Response/Disposition
IPEEE-TE Page 8	SLC seismic capacity.	The RPS system is very reliable with significant redundancy built into the function. Because of this, RRCS and SLC need not be "safety related" nor "seismic Category I" under the Regulations. The 0.5g HCLPF fragility in the PRA model incorporates RPS seismic failure. The frequency of seismic initiator and failure of RPS (non-seismic) during seismic initiating event is low in the PRA. Given this low risk and dependency on the operators in the ATWS model, no RRCS or SLC seismic evaluations are needed.
IPEEE-TE Page 9	HEP of 0.01 for depressurization equates to unreliability of all low pressure injection.	Depressurization is redundant to RCIC and HPCS for the 0.23 HCLPF success paths. This is included in the PRA.
IPEEE-TE Page 9	SBO procedure modification needed relative to depressurization and minimizing depletion of nitrogen.	EOPs address how to conserve nitrogen, specifically, EOP-RPV and EOP-C3. SOP-1 and SOP-2 have specific actions on how to conserve battery power. Separate criteria are given for blackout in lieu of the normal HCTL limits in EOP-6 Section 29.
IPEEE-TE Page 11	Consideration of human actions in the SMA not entirely in keeping with SMA guidance.	Compliance with SMA is believed to be in the IPEEE. The TE states that seismic PRA fully considered human actions and suggests safety significance is low.
IPEEE-TE Page 13	Consideration of piping degradation (e.g., wear) and impact on seismic flooding risk not included.	The 0.5g HCLPF fragility in the PRA incorporates this risk. The probability of degradation below this seismic capacity is negligible.
IPEEE-TE Page 27	No dependency matrix was provided and plant unique phenomena were not addressed.	NMP response to NRC questions provided IPE dependency matrix. No other important or unique dependencies or phenomena were identified.
IPEEE-TE Page 35,36	Approach to identifying other external events was not comprehensive.	NMP did consider other external hazards listed in the PRA procedures guide. This was not documented because it was not requested by the IPEEE scope.
IPEEE-TE Page 36	Little detail provided on systems interactions.	NMP believes that the present effort is reasonable.
IPEEE-TE Page 36	No specific information was provided concerning smoke impact on fire fighting effectiveness.	Smoke can affect fire fighting effectiveness and this is considered in training, etc.
IPEEE-TE Page 43	Seismic hazard assessment was truncated at 1.02g.	This will not impact the results, but will be considered in a future update.

[1] SE = Staff Evaluation (Enclosure 1 to NRC letter); TE = Technical Evaluation (Enclosure 2 to NRC letter)

ATTACHMENT 6

UPDATED PRA RESULTS SUMMARY

Summary of Baseline Model U2BASER1

Internal and External Events CDF	3.5E-5/yr
Internal and External Events LERF	8.3E-7/yr
Shutdown CDF	Not Evaluated
Configuration Risk Management Tool	Safety Monitor

Accident Sequence Contribution to CDF		
Initiator ID	**Initiator Description**	**%CDF Contribution**
BLOSP	Loss of Offsite Power and Diesel Failure (SBO)	28.6
ASX	Loss of Instrument Air	2.7
LOF	Loss of Main Feedwater System	2.7
BFLCB	Flood in the Control Building - Blackout	2.4
LOSP	Loss of Offsite Power	1.7
BLOSP	Loss of Offsite Power and Diesel Failure (SBO)	1.4
BLOSP	Loss of Offsite Power and Diesel Failure (SBO)	1.2
MLOCA	Medium LOCA	1.2
BLOSP	Loss of Offsite Power and Diesel Failure (SBO)	1.2
ATT	Turbine Trip - ATWS	0.9

Top 10 Dominant Baseline Core Damage Sequences	
Core Damage Sequence Description	**Freq (/yr)**
A Station Blackout given an LOSP where the Operators fail to: align the Diesel Fire Pump; crosstie the HPCS Diesel; and recover the Offsite Grid or an Emergency Diesel Generator (Div. 1 or 2) in the first 30 minutes, with High Pressure Injection unavailable due to RCIC equipment and support failures.	1.0E-5
Total Loss of Instrument Air where the Operators fail to depressurize the Reactor Pressure Vessel (RPV), with RCIC and HPCS unavailable due to equipment and support failures.	9.6E-7
A Loss of Feedwater event where the Operators fail to depressurize the RPV, and RCIC and HPCS are unavailable due to equipment and support failures.	9.6E-7
A Control Building Flood occurs during a Station Blackout event given a LOSP and Operators fail to isolate the water source, which leads to multiple vital equipment failures.	8.6E-7
An LOSP occurs where the Offsite Grid is not recovered in the first 30 minutes and the Operators fail to depressurize the RPV, with RCIC and HPCS unavailable due to equipment and support failures.	5.9E-7
A Station Blackout given an LOSP where the Operators fail to: align the Diesel Fire Pump; crosstie the HPCS Diesel; and recover the Offsite Grid or an Emergency Diesel within the first 30 minutes, with RCIC failed due loss of UPS support.	4.9E-7
A Station Blackout given a LOSP where: the Offsite Grid or an EDG (Div. 1 or 2) is not recovered and Fire Water is not aligned within the first 30 minutes, with RCIC unavailable due to equipment failures. In addition, the HPCS EDG crosstie to Div. 1 fails with the Div. 2 unrecoverable due to loss of DC power.	4.4E-7
A Medium LOCA event where Operators fail to depressurize, with HPCS unavailable due to equipment and support system failures.	4.2E-7
A Station Blackout given a LOSP where RCIC is successful; however, long-term (8 hours) Offsite Grid and EDG (Div. 1 or 2) recovery fails, and operators fail to crosstie the HPCS Diesel or align the Diesel Fire Pump.	3.7E-7
An Anticipated Transient Without Scram Turbine Trip event where a mechanical scram failure occurs and Liquid Poison injection fails.	3.2E-7

Summary of Model U2UPSAR1 with the Division 1 Emergency UPS Inverter Failed and Compensating Measures in Place

Internal and External Events CDF	5.1E-5
Internal and External Events LERF	1.0E-6
Shutdown CDF	Not Evaluated
Configuration Risk Management	Safety Monitor

Accident Sequence Contribution to CDF		
Initiator ID	**Initiator Description**	**%CDF Contribution**
BLOSP	Loss of Offsite Power and Diesel Failure (SBO)	41.2
BLOSP	Loss of Offsite Power and Diesel Failure (SBO)	4.1
ASX	Loss of Instrument Air	1.8
LOF	Loss of Main Feedwater System	1.8
BFLCB	Flood in the Control Building - Blackout	1.7
LOSP	Loss of Offsite Power	1.1
BLOSP	Loss of Offsite Power and Diesel Failure (SBO)	1.0
BLOSP	Loss of Offsite Power and Diesel Failure (SBO)	1.0
BSCRAM	SCRAM - Blackout	0.9
MLOCA	Medium LOCA	0.8

Top 10 Dominant Core Damage Sequences for the Division 1 Inverter Failed	
Core Damage Sequence Description	**Freq (/yr)**
A Station Blackout given an LOSP where in the first 30 minutes recovery of the Offsite Grid or an Emergency Diesel Generator (Div. 1 or 2), alignment of the Diesel Fire Pump, and crosstie of the HPCS EDG fails. RCIC fails with the Div. 1 inverter unavailable.	2.1E-5
A Station Blackout given an LOSP where in the first 30 minutes recovery of the Offsite Grid or an Emergency Diesel Generator (Div. 1 or 2), alignment of the Diesel Fire Pump, and crosstie of the HPCS EDG fails. Manual initiation of RCIC fails with the Div. 1 inverter unavailable.	2.1E-6
Total Loss of Instrument Air where the Operators fail to depressurize the RPV, with RCIC and HPCS unavailable due to failures.	9.2E-7
Total Loss of Feedwater occurs where operators fail to depressurize the RPV, and RCIC and HPCS are unavailable in the first 30 minutes due to equipment and support failures.	9.1E-7
A Control Building Flood occurs during a Station Blackout LOSP event and Operators fail to isolate the water source, which leads to multiple vital equipment failures.	8.6E-7
A Loss of Offsite Power Event where Operators fail to depressurize the RPV, and RCIC and HPCS are unavailable due to failures and Grid Recovery fails during the first 30 minutes.	5.6E-7
A Station Blackout given an LOSP where the Div. 1 inverter also fails and the Offsite Grid or one EDG is not recovered, and RCIC is failed during the first 30 minute. In addition, the HPCS EDG crosstie fails and the operators were unable to align the Diesel Fire Pump.	5.4E-7
A Station Blackout given an LOSP where the Offsite Grid or one EDG is not recovered during the first 30 minutes, and RCIC is unavailable due to ECCS auto initiation failure. In addition, the HPCS EDG crosstie fails and operators were unable to align the Diesel Fire Pump.	4.9E-7
A Blackout Scram Event where operators are unable to recover the Offsite Grid, recover one EDG, or align the Diesel Fire Pump, and RCIC fails when the Div. 1 inverter is unavailable.	4.8E-7
A Medium LOCA event where Operators fail to depressurize, with HPCS unavailable due to equipment and support system failures.	4.2E-7

Summary of Model U2UPSBR1 with the Division 2 Emergency UPS Inverter Failed and Compensating Measures in Place

Internal and External Events CDF	6.1E-5
Internal and External Events LERF	1.1E-6
Shutdown CDF	Not Evaluated
Configuration Risk Management	Safety Monitor

Accident Sequence Contribution to CDF		
Initiator ID	**Initiator Description**	**%CDF Contribution**
BLOSP	Loss of Offsite Power and Diesel Failure (SBO)	47.5
BLOSP	Loss of Offsite Power and Diesel Failure (SBO)	2.1
ASX	Loss of Instrument Air	1.5
LOF	Loss of Main Feedwater System	1.5
BFLCB	Flood in the Control Building - Blackout	1.4
A2X	Loss of Division II AC Power	1.1
BSCRAM	SCRAM – Blackout	1.0
LOSP	Loss of Offsite Power	0.9
BLOSP	Loss of Offsite Power and Diesel Failure (SBO)	0.8
BLOSP	Loss of Offsite Power and Diesel Failure (SBO)	0.7

Top 10 Dominant Core Damage Sequences for the Division 2 Inverter Failed	
Core Damage Sequence Description	**Freq (/yr)**
A Station Blackout given an LOSP where during the first 30 minutes operators are unable to recover the Offsite Grid, recover one EDG, align the Diesel Fire Pump or crosstie the HPCS EDG, and RCIC is unavailable due to equipment and support failures.	2.9E-5
A Station Blackout given an LOSP where during the first 30 minutes operators are unable to recover the Offsite Grid, recover one EDG, align the Diesel Fire Pump or crosstie the HPCS EDG, and RCIC fails due to no initiation signal.	1.3E-6
Total Loss of Instrument Air where the Operators fail to depressurize the Reactor Pressure Vessel (RPV), with RCIC and HPCS unavailable due to equipment and support failures.	9.1E-7
A Loss of Feedwater event where the Operators fail to depressurize the RPV, and RCIC and HPCS are unavailable due to equipment and support failures.	9.1E-7
A Control Building Flood occurs during a Station Blackout LOSP event and Operators fail to isolate the water source, which leads to multiple vital equipment failures.	8.6E-7
Loss of Division 2 Emergency AC power and Low Pressure Core Spray (LPCS) Fails.	6.7E-7
A Blackout Scram Event where operators within the first 30 minutes are unable to recover the Offsite Grid, recover one EDG, crosstie the HPCS EDG, or align the Diesel Fire Pump, and RCIC fails when the Div. 2 inverter is unavailable.	6.5E-7
An LOSP Event where the operators fail to depressurize and recover the Offsite Grid within the first 30 minutes, when HPCS and RCIC are unavailable due to equipment and support failures.	5.6E-7
A Station Blackout given an LOSP where operators are unable to recover the Offsite Grid within the first 30 minutes, recover one EDG, crosstie the HPCS EDG or align the Diesel Fire Pump, and RCIC fails due to loss of the Div. 1 inverter when the Div. 2 inverter is unavailable for maintenance.	4.9E-7
A Station Blackout given an LOSP where operators are unable to recover the Offsite Grid within the first 30 minutes, recover one EDG, crosstie the HPCS EDG to Division 2 or align the Diesel Fire Pump, with RCIC unavailable due to equipment and support failures.	4.3E-7

ATTACHMENT 7

TIER 1: PROBABILISTIC RISK ASSESSMENT (PRA) STUDY RESULTS

Methodology and Acceptance Criteria

Regulatory Guides (RG) 1.174 and 1.177 describe the requirements for making risk-informed changes to the Technical Specifications (TS). This evaluation provides the risk quantification inputs to these requirements. The following risk metrics were used to evaluate the risk impact of extending the Nine Mile Point Unit 2 (NMP2) emergency UPS inverter Completion Time from 24 hours to 7 days.

- ΔCDF_{ave} = Change in the annual average Core Damage Frequency due to any increased online maintenance unavailability of an emergency UPS inverter due to the TS change. This risk metric is used to compare against the criteria in RG 1.174.
- $\Delta LERF_{ave}$ = Change in the annual average Large Early Release Frequency due to any increased online maintenance unavailability of an emergency UPS inverter due to the TS change. This risk metric is used to compare against the criteria in RG 1.174.
- ICCDP = Incremental Conditional Core Damage Probability with an emergency UPS inverter out of service for the new proposed TS duration of 7 days. This risk metric is used as recommended in RG 1.177 to determine whether the proposed TS change has an acceptable risk.
- ICLERP = Incremental Conditional Large Early Release Probability with an emergency UPS inverter out of service for the new proposed TS duration of 7 days. This risk metric is used as recommended in RG 1.177 to determine whether the proposed TS change has an acceptable risk.

The change in annual average CDF due to the proposed change in emergency UPS inverter Completion Time, ΔCDF_{Ave}, is estimated as follows:

$$\Delta CDF_{Ave} = (T_I/T)*CDF_{Iout} + (T_{II}/T)*CDF_{IIout} + [1-(T_I+T_{II})/T]*CDF_{Base} - CDF_{Base} \qquad (1)$$

Where:

CDF_{Iout} = CDF estimated with the Division 1 emergency UPS inverter out of service and compensating measures implemented.

CDF_{IIout} = CDF estimated with the Division 2 emergency UPS inverter out of service and compensating measures implemented.

CDF_{Base} = Baseline annual average CDF prior to the proposed TS change.

T = Total fuel cycle time. The NMP2 fuel cycle is 2 years, and it is assumed that the plant is in planned and forced outages for a total of 40 days during the 2-year period. Thus, T= 690 days (2*365 – 40 = 690 days).

T_I = Total time per fuel cycle that the Division 1 emergency UPS inverter is out of service for the extended TS Completion Time. The proposed TS value of 7 days is used.

T_{II} = Total time per fuel cycle that the Division 2 emergency UPS inverter is out of service for the extended TS Completion Time. The proposed TS value of 7 days is used.

The change in annual average LERF due to the proposed change in emergency UPS inverter Completion Time, $\Delta LERF_{Ave}$, is estimated as follows:

$$\Delta LERF_{Ave} = (T_I/T)*LERF_{Iout} + (T_{II}/T)*LERF_{IIout} + [1-(T_I + T_{II})/T]*LERF_{Base} - LERF_{Base} \quad (2)$$

Where:

$LERF_{Iout}$ = LERF estimated with the Division 1 emergency UPS inverter out of service and compensating measures implemented.

$LERF_{IIout}$ = LERF estimated with the Division 2 emergency UPS inverter out of service and compensating measures implemented.

$LERF_{Base}$ = Baseline annual average LERF prior to the proposed TS change.

The acceptance criterion for change in CDF and LERF in RG 1.174 is as follows:

< 1E-6 change in CDF is non-risk significant
< 1E-7 change in LERF is non-risk significant

ICCDP and ICLERP are calculated using the definitions in RG 1.177 as follows:

$$ICCDP_I = (CDF_{Iout} - CDF_{Base})*(7\ days) \quad (3)$$
$$ICCDP_{II} = (CDF_{IIout} - CDF_{Base})*(7\ days) \quad (4)$$
$$ICLERP_I = (LERF_{Iout} - LERF_{Base})*(7\ days) \quad (5)$$
$$ICLERP_{II} = (LERF_{IIout} - LERF_{Base})*(7\ days) \quad (6)$$

The acceptance criteria for changes in RG 1.177 are as follows:

ICCDP < 5E-7
ILERP < 5E-8

RG 1.177 also discusses component importance measures, risk achievement worth (RAW) and Fussel-Vesely (FV) importance. This is provided for the baseline PRA without consideration of any compensating measures that may be taken to minimize risk impact.

Assumptions

The following are the key assumptions used in the analysis to support extension of the emergency UPS inverter Completion Time:

- Assumptions contained in the NMP2 PRA apply to this evaluation.
- The important configuration risk management controls and compensating measures assumed in this analysis are described in Section 4.2.5 of Attachment 1.
- Data from draft NUREG/CR-INEEL/EXT-04-02525, "Station Blackout Risk Evaluation for Nuclear Power Plants," January 2005, is used for the NMP2 LOSP frequency and non-restoration probabilities.
- A 7-day emergency UPS inverter outage is assumed to occur once per fuel cycle.
- A total of 40 days of planned and forced outage time per 2-year fuel cycle.
- Compensating measures summarized in Section 4.2.5 of Attachment 1 and associated failure probabilities are assumed.

Calculations

The following CDF and LERF values for an emergency UPS inverter out of service were calculated with the NMP2 PRA (see Attachment 6) to perform the risk metric calculations required by RGs 1.174 and 1.177, using a 1E-12/yr truncation. Note that the calculations include the compensating measures included in the PRA model as described in Section 4.2.5 of Attachment 1.

CDF_{Iout} = 5.1E-5/year (Div. 1 inverter unavailable with compensating measures)
CDF_{IIout} = 6.1E-5/year (Div. 2 inverter unavailable with compensating measures)
$LERF_{Iout}$ = 1.0E-6/year (Div. 1 inverter unavailable with compensating measures)
$LERF_{IIout}$ = 1.1E-6/year (Div. 2 inverter unavailable with compensating measures)

The following CDF and LERF baseline values (see Attachment 6) are also required inputs to the risk metric calculations:

CDF_{Base} = 3.5E-5/year (baseline average maintenance PRA model)
$LERF_{Base}$ = 8.3E-7/year (baseline average maintenance PRA model)

Using the above inputs and Equations (1) through (6), the following risk metric values are calculated:

ΔCDF_{Ave} = 4.2E-7/yr (acceptance criteria is <1E-6)
$\Delta LERF_{Ave}$ = 4.4E-9/yr (acceptance criteria is <1E-7)
$ICCDP_{I}$ = 3.0E-7 (acceptance criteria is <5E-7)
$ICCDP_{II}$ = 4.9E-7 (acceptance criteria is <5E-7)
$ICLERP_{I}$ = 3.2E-9 (acceptance criteria is <5E-8)
$ICLERP_{II}$ = 5.1E-9 (acceptance criteria is <5E-8)

ATTACHMENT 8

DOMINANT CDF AND LERF SEQUENCES THAT CONTAIN THE EMERGENCY UPS INVERTERS

TABLES

Table 1
Division 1 Emergency UPS Inverter Core Damage Frequency (CDF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): CDF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
1	BLOSP	5.68E-002	BLACKOUT LOSP	CLASSIB	1.8848E-005	36.46
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	UCFSAM	1.00E+000	- System - UA and UB			
	E3FSB	9.88E-001	- System - E1 and E2			
	U17	2.00E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
2	BLOSP	5.68E-002	BLACKOUT LOSP	CLASSIB	2.0944E-006	4.05
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	UCFSAM	1.00E+000	- System - UA and UB			
	E3FSB	9.88E-001	- System - E1 and E2			
	ME1	1.00E-001	- Manual ECCS Actuation			
	U17	2.00E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
3	BLOSP	5.68E-002	BLACKOUT LOSP	CLASSIB	1.1493E-006	2.22
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	UCFSAM	1.00E+000	- System - UA and UB			

Table 1
Division 1 Emergency UPS Inverter Core Damage Frequency (CDF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): CDF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
	E3FFB	1.20E-002	- System - E1 and E2			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
4	ASX	1.40E-001	LOSS OF INSTRUMENT AIR	CLASSIA	9.1626E-007	1.77
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	A3SSM	1.00E+000	- System - A1 and A2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			
	DC3SSA	1.00E+000	- System - Div I (DC1) and Div II (DC2) Battery Chargers			
	UCSSA	1.00E+000	- System - UA and UB			
	E3SSA	9.75E-001	- System - E1 and E2			
	MABSSA	9.93E-001	- System - MA and MB			
	IC1	1.76E-001	- RCIC - TRAN & SLOCA Response			
	HS1	4.86E-002	- High Pressure Core Spray			
	OD1	1.00E-003	- Operator Depressurzes for LPI - TRAN & SLOCA			
	LABSSA	9.53E-001	- System - LA, LB			
	IABSSA	9.73E-001	- System - LPCI Injection Pathes A and B (IA, IB)			
	HCSSA	9.88E-001	- System - HA and HB			
	P3SSA	9.95E-001	- System - PA and PB			
	CCSSA	9.82E-001	- Containment Spray System - CA and CB			
5	LOF	1.40E-001	LOSS OF FEEDWATER	CLASSIA	9.1463E-007	1.77
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	A3SSM	1.00E+000	- System - A1 and A2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			

Table 1
Division 1 Emergency UPS Inverter Core Damage Frequency (CDF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): CDF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
	DC3SSA	1.00E+000	- System - Div I (DC1) and Div II (DC2) Battery Chargers			
	UCSSA	1.00E+000	- System - UA and UB			
	E3SSA	9.75E-001	- System - E1 and E2			
	MABSSA	9.93E-001	- System - MA and MB			
	IC1	1.76E-001	- RCIC - TRAN & SLOCA Response			
	HS1	4.86E-002	- High Pressure Core Spray			
	OD1	1.00E-003	- Operator Depressurzes for LPI - TRAN & SLOCA			
	LABSSA	9.53E-001	- System - LA, LB			
	IABSSA	9.73E-001	- System - LPCI Injection Pathes A and B (IA, IB)			
	HCSSA	9.88E-001	- System - HA and HB			
	P3SSA	9.95E-001	- System - PA and PB			
	CCSSA	9.82E-001	- Containment Spray System - CA and CB			
6	BFLCB	9.30E-004	Flood in the Control Bldg	CLASSIB	8.5740E-007	1.66
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	IER1	1.00E-003	- Initiating Event Recovery			
	DABSSA	9.99E-001	- System - DA and DB			
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			
7	BLOSP	5.68E-002	BLACKOUT LOSP	CLASSIB	7.8532E-007	1.52
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	UCFSAM	1.00E+000	- System - UA and UB			
	E3FSB	9.88E-001	- System - E1 and E2			
	U17	2.00E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
8	LOSP	5.68E-002	LOSS OF OFFSITE AC	CLASSIA	5.6521E-007	1.09

Table 1
Division 1 Emergency UPS Inverter Core Damage Frequency (CDF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): CDF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3SSJ	9.07E-001	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	DC3SSA	1.00E+000	- System - Div I (DC1) and Div II (DC2) Battery Chargers			
	UCSSA	1.00E+000	- System - UA and UB			
	E3SSA	9.75E-001	- System - E1 and E2			
	SXXSSC	1.00E+000	- System - Service Water (SWS, SWA)			
	MABSSA	9.93E-001	- System - MA and MB			
	IC1	1.76E-001	- RCIC - TRAN & SLOCA Response			
	HS2	1.14E-001	- High Pressure Core Spray			
	OD1	1.00E-003	- Operator Depressurzes for LPI - TRAN & SLOCA			
	LABSSA	9.53E-001	- System - LA, LB			
	IABSSA	9.73E-001	- System - LPCI Injection Pathes A and B (IA, IB)			
	HCSSA	9.88E-001	- System - HA and HB			
	P3SSA	9.95E-001	- System - PA and PB			
	CCSSA	9.82E-001	- Containment Spray System - CA and CB			
9	BLOSP	5.68E-002	BLACKOUT LOSP	CLASSIB	5.4099E-007	1.05
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSFA	4.22E-004	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFH	5.09E-002	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30	9.30E-001	- EDG Recovery			
	HPCS5	8.62E-001	- HPCS EDG Crossitie to Div I or II - SBO			
10	BLOSP	5.68E-002	BLACKOUT LOSP	CLASSIB	4.8648E-007	0.94
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABFSA	4.22E-004	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFE	4.63E-002	- System - A1 and A2			

Table 1
Division 1 Emergency UPS Inverter Core Damage Frequency (CDF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): CDF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
	PCH1	9.60E-001	- Portable Charger			
	UCFSAZ	1.00E+000	- System - UA and UB			
	E3FSB	9.88E-001	- System - E1 and E2			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30	9.30E-001	- EDG Recovery			
	HPCS3	8.62E-001	- HPCS EDG Crossitie to Div I or II - SBO			
11	BSCRAM	4.80E+000	BLACKOUT SHUTDOWN OR SCRAM	CLASSIB	4.8001E-007	0.93
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	OG1	3.01E-004	- Offsite Grid			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	UCFSAM	1.00E+000	- System - UA and UB			
	E3FSB	9.88E-001	- System - E1 and E2			
	U17	2.00E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
12	MLOCA	3.00E-003	MEDIUM LOCA	CLASSIIIB	4.1759E-007	0.81
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	A3SSM	1.00E+000	- System - A1 and A2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			
	DC3SSA	1.00E+000	- System - Div I (DC1) and Div II (DC2) Battery Chargers			
	UCSSA	1.00E+000	- System - UA and UB			
	E3SSD	9.95E-001	- System - E1 and E2			
	MABSSA	9.93E-001	- System - MA and MB			
	HS7	5.93E-002	- High Pressure Core Spray			

Table 1
Division 1 Emergency UPS Inverter Core Damage Frequency (CDF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): CDF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
	OD2	3.00E-003	- Operator Depressurzes for LPI - TRAN & SLOCA			
	LABSSA	9.53E-001	- System - LA, LB			
	IABSSA	9.73E-001	- System - LPCI Injection Pathes A and B (IA, IB)			
	HCSSD	9.91E-001	- System - HA and HB			
	P3SSA	9.95E-001	- System - PA and PB			
	CCSSA	9.82E-001	- Containment Spray System - CA and CB			

Total Quantified Frequency of Sequence Group = 5.1694E-005

Table 2
Division 2 Emergency UPS Inverter Core Damage Frequency (CDF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): CDF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
1	BLOSP	5.68E-002	BLACKOUT LOSP	CLASSIB	2.5345E-005	41.48
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	UCSFAM	1.00E+000	- System - UA and UB			
	E3SFC	9.87E-001	- System - E1 and E2			
	U16	2.69E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
2	BLOSP	5.68E-002	BLACKOUT LOSP	CLASSIB	2.8164E-006	4.61
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	UCSFAM	1.00E+000	- System - UA and UB			
	E3SFC	9.87E-001	- System - E1 and E2			
	ME1	1.00E-001	- Manual ECCS Actuation			
	U16	2.69E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
3	BLOSP	5.68E-002	BLACKOUT LOSP	CLASSIB	1.2671E-006	2.07
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	UCSFAM	1.00E+000	- System - UA and UB			

Table 2
Division 2 Emergency UPS Inverter Core Damage Frequency (CDF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): CDF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
	E3FFC	1.33E-002	- System - E1 and E2			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
4	BLOSP	5.68E-002	BLACKOUT LOSP	CLASSIB	1.0560E-006	1.73
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	UCSFAM	1.00E+000	- System - UA and UB			
	E3SFC	9.87E-001	- System - E1 and E2			
	U16	2.69E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
5	ASX	1.40E-001	LOSS OF INSTRUMENT AIR	CLASSIA	9.1455E-007	1.50
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	A3SSM	1.00E+000	- System - A1 and A2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			
	DC3SSA	1.00E+000	- System - Div I (DC1) and Div II (DC2) Battery Chargers			
	UCSSA	1.00E+000	- System - UA and UB			
	E3SSA	9.75E-001	- System - E1 and E2			
	MABSSA	9.93E-001	- System - MA and MB			
	IC1	1.76E-001	- RCIC - TRAN & SLOCA Response			
	HS1	4.86E-002	- High Pressure Core Spray			
	OD1	1.00E-003	- Operator Depressurzes for LPI - TRAN & SLOCA			
	LABSSA	9.53E-001	- System - LA, LB			
	IABSSA	9.73E-001	- System - LPCI Injection Pathes A and B (IA, IB)			

Table 2
Division 2 Emergency UPS Inverter Core Damage Frequency (CDF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): CDF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
	HCSSA	9.88E-001	- System - HA and HB			
	P3SSA	9.95E-001	- System - PA and PB			
	CCSSA	9.82E-001	- Containment Spray System - CA and CB			
6	LOF	1.40E-001	LOSS OF FEEDWATER	CLASSIA	9.1292E-007	1.49
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	A3SSM	1.00E+000	- System - A1 and A2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			
	DC3SSA	1.00E+000	- System - Div I (DC1) and Div II (DC2) Battery Chargers			
	UCSSA	1.00E+000	- System - UA and UB			
	E3SSA	9.75E-001	- System - E1 and E2			
	MABSSA	9.93E-001	- System - MA and MB			
	IC1	1.76E-001	- RCIC - TRAN & SLOCA Response			
	HS1	4.86E-002	- High Pressure Core Spray			
	OD1	1.00E-003	- Operator Depressurzes for LPI - TRAN & SLOCA			
	LABSSA	9.53E-001	- System - LA, LB			
	IABSSA	9.73E-001	- System - LPCI Injection Pathes A and B (IA, IB)			
	HCSSA	9.88E-001	- System - HA and HB			
	P3SSA	9.95E-001	- System - PA and PB			
	CCSSA	9.82E-001	- Containment Spray System - CA and CB			
7	BFLCB	9.30E-004	Flood in the Control Bldg	CLASSIB	8.5740E-007	1.40
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	IER1	1.00E-003	- Initiating Event Recovery			
	DABSSA	9.99E-001	- System - DA and DB			
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			
8	A2X	6.01E-003	Loss of Emergency AC Div II	CLASSID	6.7311E-007	1.10

Table 2
Division 2 Emergency UPS Inverter Core Damage Frequency (CDF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): CDF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	A3SFI	1.00E+000	- System - A1 and A2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			
	DC3SFP	1.00E+000	- System - Div I (DC1) and Div II (DC2) Battery Chargers			
	UCSFU	1.00E+000	- System - UA and UB			
	E3SFC	9.87E-001	- System - E1 and E2			
	SWS14A	4.26E-003	- Service Water Div I & II Pump Trains - Crosstie Open			
	LS1	3.26E-002	- Low Pressure Core Spray			
	IABSFC	9.86E-001	- System - LPCI Injection Pathes A and B (IA, IB)			
9	BSCRAM	4.80E+000	BLACKOUT SHUTDOWN OR SCRAM	CLASSIB	6.4548E-007	1.06
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	OG1	3.01E-004	- Offsite Grid			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	UCSFAM	1.00E+000	- System - UA and UB			
	E3SFC	9.87E-001	- System - E1 and E2			
	U16	2.69E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
10	LOSP	5.68E-002	LOSS OF OFFSITE AC	CLASSIA	5.6415E-007	0.92
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3SSJ	9.07E-001	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			

Table 2
Division 2 Emergency UPS Inverter Core Damage Frequency (CDF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): CDF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
	DC3SSA	1.00E+000	- System - Div I (DC1) and Div II (DC2) Battery Chargers			
	UCSSA	1.00E+000	- System - UA and UB			
	E3SSA	9.75E-001	- System - E1 and E2			
	SXXSSC	1.00E+000	- System - Service Water (SWS, SWA)			
	MABSSA	9.93E-001	- System - MA and MB			
	IC1	1.76E-001	- RCIC - TRAN & SLOCA Response			
	HS2	1.14E-001	- High Pressure Core Spray			
	OD1	1.00E-003	- Operator Depressurzes for LPI - TRAN & SLOCA			
	LABSSA	9.53E-001	- System - LA, LB			
	IABSSA	9.73E-001	- System - LPCI Injection Pathes A and B (IA, IB)			
	HCSSA	9.88E-001	- System - HA and HB			
	P3SSA	9.95E-001	- System - PA and PB			
	CCSSA	9.82E-001	- Containment Spray System - CA and CB			
11	BLOSP	5.68E-002	BLACKOUT LOSP	CLASSIB	4.9252E-007	0.81
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABFSA	4.22E-004	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFE	4.63E-002	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30	9.30E-001	- EDG Recovery			
	HPCS3	8.62E-001	- HPCS EDG Crossitie to Div I or II - SBO			
12	BLOSP	5.68E-002	BLACKOUT LOSP	CLASSIB	4.2639E-007	0.70
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3SFJ	4.20E-002	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	DC3SFP	1.00E+000	- System - Div I (DC1) and Div II (DC2) Battery Chargers			
	UCSFU	1.00E+000	- System - UA and UB			
	E3SFC	9.87E-001	- System - E1 and E2			
	XTC3	1.69E-003	- Service Water Cross-tie Fails to Close on Demand			

Table 2
Division 2 Emergency UPS Inverter Core Damage Frequency (CDF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): CDF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
	U16	2.69E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30	9.30E-001	- EDG Recovery			
	HPCS3	8.62E-001	- HPCS EDG Crossitie to Div I or II - SBO			
13	MLOCA	3.00E-003	MEDIUM LOCA	CLASSIIIB	4.1759E-007	0.68
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	A3SSM	1.00E+000	- System - A1 and A2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			
	DC3SSA	1.00E+000	- System - Div I (DC1) and Div II (DC2) Battery Chargers			
	UCSSA	1.00E+000	- System - UA and UB			
	E3SSD	9.95E-001	- System - E1 and E2			
	MABSSA	9.93E-001	- System - MA and MB			
	HS7	5.93E-002	- High Pressure Core Spray			
	OD2	3.00E-003	- Operator Depressurzes for LPI - TRAN & SLOCA			
	LABSSA	9.53E-001	- System - LA, LB			
	IABSSA	9.73E-001	- System - LPCI Injection Pathes A and B (IA, IB)			
	HCSSD	9.91E-001	- System - HA and HB			
	P3SSA	9.95E-001	- System - PA and PB			
	CCSSA	9.82E-001	- Containment Spray System - CA and CB			

Total Quantified Frequency of Sequence Group = 6.1108E-005

Table 3
Division 1 Emergency UPS Inverter Large Early Release Frequency (LERF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): LERF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
1	BLOSP	5.68E-002	BLACKOUT LOSP	EHI	5.4836E-008	5.46
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	UCFSAM	1.00E+000	- System - UA and UB			
	E3FSB	9.88E-001	- System - E1 and E2			
	U17	2.00E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
	GV2	9.90E-001	- CET1 - Combustible Gas Venting			
	CZB	5.50E-003	- CET1 - Containment Isolated and Intact			
2	BFLCB	9.30E-004	Flood in the Control Bldg	EHI	4.8068E-008	4.78
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	IER1	1.00E-003	- Initiating Event Recovery			
	DABSSA	9.99E-001	- System - DA and DB			
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			
	IS3	1.05E-001	- CET1 & 3 - Containment Isolation			
	RB7	9.90E-001	- CET2 - Reactor Bldg Effectiveness			
3	BLOSP	5.68E-002	BLACKOUT LOSP	EHI	4.3641E-008	4.34
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	UCFSAM	1.00E+000	- System - UA and UB			
	E3FSB	9.88E-001	- System - E1 and E2			

Table 3
Division 1 Emergency UPS Inverter Large Early Release Frequency (LERF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): LERF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
	U17	2.00E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
	IRE	4.00E-001	- CET1 - Invessel Recovery			
	CZD	6.50E-003	- CET1 - Containment Isolated and Intact			
4	BFLCB	9.30E-004	Flood in the Control Bldg	EHI	4.0006E-008	3.98
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	IER1	1.00E-003	- Initiating Event Recovery			
	DABSSA	9.99E-001	- System - DA and DB			
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			
	IS3	1.05E-001	- CET1 & 3 - Containment Isolation			
	OP1	4.55E-001	- CET2 - Operator RPV Depressurization			
	RB7	9.90E-001	- CET2 - Reactor Bldg Effectiveness			

Total Quantified Frequency of Sequence Group = 1.0050E-006

Table 4
Division 2 Emergency UPS Inverter Large Early Release Frequency (LERF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): LERF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
1	BLOSP	5.68E-002	BLACKOUT LOSP	EHI	7.3739E-008	6.76
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	UCSFAM	1.00E+000	- System - UA and UB			
	E3SFC	9.87E-001	- System - E1 and E2			
	U16	2.69E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
	GV2	9.90E-001	- CET1 - Combustible Gas Venting			
	CZB	5.50E-003	- CET1 - Containment Isolated and Intact			
2	BLOSP	5.68E-002	BLACKOUT LOSP	EHI	5.8684E-008	5.38
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	DABSSA	9.99E-001	- System - DA and DB			
	OGR1	7.10E-001	- Offsite power recovery w/in 30 minutes			
	A3FFJ	4.32E-003	- System - A1 and A2			
	PCH1	9.60E-001	- Portable Charger			
	UCSFAM	1.00E+000	- System - UA and UB			
	E3SFC	9.87E-001	- System - E1 and E2			
	U16	2.69E-001	- RCIC - Station Blackout (0-2 HRS)			
	S11	8.40E-001	- Diesel Fire Pump - SBO (2-8 HRS)			
	EDG30M	9.10E-001	- EDG Recovery			
	HPCS1	8.60E-001	- HPCS EDG Crossitie to Div I or II - SBO			
	IRE	4.00E-001	- CET1 - Invessel Recovery			
	CZD	6.50E-003	- CET1 - Containment Isolated and Intact			
3	BFLCB	9.30E-004	Flood in the Control Bldg	EHI	4.8068E-008	4.40
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	IER1	1.00E-003	- Initiating Event Recovery			
	DABSSA	9.99E-001	- System - DA and DB			

Table 4
Division 2 Emergency UPS Inverter Large Early Release Frequency (LERF) Sequences

Top-Ranked Sequences Contributing to Group (Sorted by Frequency): LERF

Rank	IE/SF	Value	Sequence Description	Bin	Frequency	Percent of Group
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			
	IS3	1.05E-001	- CET1 & 3 - Containment Isolation			
	RB7	9.90E-001	- CET2 - Reactor Bldg Effectiveness			
4	BFLCB	9.30E-004	Flood in the Control Bldg	EHI	4.0006E-008	3.67
	POSA	9.90E-001	- Top Event for Setting Plant Mode/POS			
	IER1	1.00E-003	- Initiating Event Recovery			
	DABSSA	9.99E-001	- System - DA and DB			
	KASSC	9.96E-001	- System - KA1 and KA2			
	KBSSC	9.96E-001	- System - KB1 and KB2			
	NABSSA	9.89E-001	- System - NA and NB			
	PCH1	9.60E-001	- Portable Charger			
	IS3	1.05E-001	- CET1 & 3 - Containment Isolation			
	OP1	4.55E-001	- CET2 - Operator RPV Depressurization			
	RB7	9.90E-001	- CET2 - Reactor Bldg Effectiveness			

Total Quantified Frequency of Sequence Group = 1.0914E-006