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Sam Belcher
Vice President-Nine Mile Point

P.O. Box 63
Lycoming, New York 13093
315.349.5200
315.349.1321 Fax

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NINE MILE POINT
NUCLEAR STATION

January 14, 2011

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

ATTENTION: Document Control Desk

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

License Amendment Request Pursuant to 10 CFR 50.90: Extension of the Completion Time for an Inoperable Diesel Generator – Response to NRC Request for Additional Information (TAC No. ME3736)

REFERENCES:

(a) Letter from S. Belcher (NMPNS) to Document Control Desk (NRC), dated March 30, 2010, License Amendment Request Pursuant to 10 CFR 50.90: Extension of the Completion Time for an Inoperable Diesel Generator – Technical Specification 3.8.1, AC Sources – Operating

(b) Letter from T. A. Lynch (NMPNS) to Document Control Desk (NRC), dated June 1, 2010, License Amendment Request Pursuant to 10 CFR 50.90: Extension of the Completion Time for an Inoperable Diesel Generator – Response to NRC Acceptance Review Comments (TAC No. ME3736)

(c) Letter from R. V. Guzman (NRC) to S. L. Belcher (NMPNS), dated December 15, 2010, Request for Additional Information Regarding Nine Mile Point Nuclear Station, Unit No. 2 – Re: Extension of Completion Time for Inoperable Diesel Generator – Probability Risk Assessment Review (TAC No. ME3736)

Nine Mile Point Nuclear Station, LLC (NMPNS) hereby transmits supplemental information requested by the NRC in support of a previously submitted request for amendment to Nine Mile Point Unit 2 (NMP2) Renewed Operating License NPF-69. The initial request, dated March 30, 2010 (Reference a), as supplemented by Reference (b), proposed to modify Technical Specification (TS) 3.8.1, "AC Sources – Operating," to extend the Completion Time for an inoperable Division 1 or Division 2 diesel generator

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(DG) from 72 hours to 14 days. The supplemental information, provided in Attachment 1 to this letter, responds to the request for additional information (RAI) documented in the NRC's letter dated December 15, 2010 (Reference c).

Pursuant to 10 CFR 50.91(b)(1), NMPNS has provided a copy of this supplemental information to the appropriate state representative. A revised list of regulatory commitments is provided in Attachment 2. Associated changes to the marked-up TS Bases pages are provided in Attachment 3.

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

Very truly yours,

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

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

Subscribed and sworn before me, a Notary Public in and for the State of New York and County of Oswego, this 14 day of January, 2011.

WITNESS my Hand and Notarial Seal:

Lisa M. Doran
Notary Public

My Commission Expires:

9/12/2013
Date

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

SB/DEV

Attachments:
1. Nine Mile Point Unit 2 – Response to NRC Request for Additional Information Regarding the Proposed Extension of the Completion Time for an Inoperable Diesel Generator from 72 Hours to 14 Days
2. List of Regulatory Commitments
3. Changes to Technical Specification Bases (Mark-up) – Revised

cc: Regional Administrator, Region I, NRC
Project Manager, NRC
Resident Inspector, NRC
A. L. Peterson, NYSERDA

ATTACHMENT 1

NINE MILE POINT UNIT 2

RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION REGARDING THE PROPOSED EXTENSION OF THE COMPLETION TIME FOR AN INOPERABLE DIESEL GENERATOR FROM 72 HOURS TO 14 DAYS

Nine Mile Point Nuclear Station, LLC
January 14, 2011

ATTACHMENT 1

NINE MILE POINT UNIT 2
RESPONSE TO NRC REQUEST FOR ADDITIONAL INFORMATION REGARDING THE PROPOSED EXTENSION OF THE COMPLETION TIME FOR AN INOPERABLE DIESEL GENERATOR FROM 72 HOURS TO 14 DAYS

By letter dated March 30, 2010, as supplemented by letter dated June 1, 2010, Nine Mile Point Nuclear Station, LLC (NMPNS) requested an amendment to the Nine Mile Point Unit 2 (NMP2) Renewed Facility Operating License NPF-69. The proposed amendment would modify Technical Specification (TS) 3.8.1, "AC Sources – Operating," to extend the Completion Time (CT) for an inoperable Division 1 or Division 2 diesel generator (DG) from 72 hours to 14 days. This attachment provides supplemental information in response to the request for additional information relating to the staff's probabilistic risk assessment review, as documented in the NRC's letter dated December 15, 2010. Each individual NRC question is repeated (in italics), followed by the NMPNS response.

RAI-1

The licensee has identified in Section 3.1.1 of its submittal that the Division 3 DG will be available as an alternate source of alternating current (AC) power, and that this source has been credited in the probabilistic risk assessment (PRA) analysis supporting this request. Required Action 3.8.1.e of the NMP2 TSs allow up to 24 hours to restore the Division 3 DG if it is concurrently unavailable with either a Division 1 or Division 2 DG. However, the Division 3 DG is not required to be operable under the limiting condition for operation (LCO) if the High Pressure Core Spray (HPCS) System is inoperable, pursuant to TS 3.5.1. Therefore, the proposed TS does not assure the availability of the Division 3 DG, which is inconsistent with the risk analysis supporting the request. (The sensitivity analyses provided by the licensee show that the incremental conditional core damage probability (ICCDP) increases to more than four times the acceptance guidance of Regulatory Guide (RG) 1.177 if the Division 3 DG is unavailable.) The licensee needs to propose appropriate TS action requirements to assure the operability of the Division 3 DG while an extended completion time (CT) is in effect for either of the other two DGs such that the assumptions of its supporting analyses are maintained.

Response RAI-1

As noted in the March 30, 2010 NMPNS submittal, prior to utilizing the extended DG CT (greater than 72 hours and up to 14 days), operability of the HPCS system and the Division 3 (HPCS) DG will be confirmed, with no planned maintenance or testing activities scheduled. This confirmation is a pre-requisite for entering the extended DG CT.

The TS operability requirements applicable to the HPCS system are contained in Technical Specification (TS) 3.5.1 for the HPCS system and in TS 3.8.1 for the Division 3 (HPCS) DG. Both the HPCS system and the HPCS DG are required to be operable in Modes 1, 2, and 3. As specified in TS 3.8.1, if the HPCS DG became inoperable during the time that the Division 1 or Division 2 DG was already inoperable, Required Action E.1 would require that the HPCS DG be restored to operable status within 24 hours. At the end of this 24-hour period, the HPCS system could be declared inoperable in accordance with the Applicability Note for TS 3.8.1, and Condition E could be exited with only one required DG remaining inoperable. However, with a Division 1 or Division 2 DG remaining inoperable and the HPCS system declared inoperable, a redundant required feature failure would exist. Then, in accordance with TS 3.8.1, Required Action B.2, the required features supported by the Division 1 or Division 2 DG would need to be declared inoperable within 4 hours. These required features would include the low pressure emergency core cooling system (ECCS) injection/spray subsystems supported by the Division 1 or Division 2 DG. With both the HPCS system and one division of low pressure ECCS injection/spray subsystems declared inoperable, TS 3.5.1, Required Action H, would require immediate entry into LCO 3.0.3, which would require initiation of a plant shutdown. Thus, with a Division 1 or Division 2 DG already out of service and declared inoperable, the longest time that the HPCS DG could subsequently be inoperable prior to initiating a TS-required plant shutdown would be 28 hours. No further TS requirements are deemed necessary to support the proposed DG CT extension.

RAI-2

In Section 3.1.1 of the submittal in the discussion of defense-in-depth, the PRA analysis is identified as crediting 1) temporary backup AC power for battery chargers, 2) portable power supplies for reactor pressure vessel (RPV) pressure control capability, and 3) fire protection cooling water supply to the Division 3 DG. In addition, the tier 2 evaluation in Section 3.2.5 of the submittal identifies the HPCS System, Reactor Core Isolation Cooling (RCIC) System, Residual Heat Removal (RHR) System, Low Pressure Core Spray (LPCS) System, and various reactivity control systems including Standby Liquid Control (SLC) as being credited in the PRA analyses. There are no TS controls which assure these functions are available while an extended CT is in effect. (The sensitivity analyses provided by the licensee show that the ICCDP for RCIC and RHR increase significantly above the acceptance guidance of RG 1.177 when these systems are unavailable. No evaluation of multiple concurrent unavailabilities has been done for other systems which, individually, are not as significant.) The licensee needs to propose appropriate TS action requirements to assure the availability of this compensatory equipment while an extended CT is in effect such that the assumptions of its defense-in-depth evaluation are maintained.

Response RAI-2

It is not necessary to establish new TS requirements to implement the compensatory measures and configuration risk management controls that are credited in the PRA analysis for the proposed DG CT extension amendment.

The requirements for TS limiting conditions for operation (LCOs) are established in 10 CFR 50.36, which states:

> "Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met."

The definition of "remedial actions" is described in the Improved Standard Specifications (NUREG-1434), which states:

> "ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times."

The Tier 2 compensatory measures and configuration risk management controls identified for the proposed DG CT extension amendment do not meet the requirements for inclusion in the TS as ACTION statements. These measures are in support of a PRA-based analysis and are pre-requisites for entering the extended DG CT. They are not remedial actions to be taken if the LCO is not met, and they do not have specified completion times.

Regulatory Guide (RG) 1.177 provides the option to address Tier 2 compensatory measures and configuration risk management controls in the TS or in plant procedures. For the identified Tier 2 compensatory measures and configuration risk management controls, NMPNS considers it appropriate to treat these measures and controls as regulatory commitments and to incorporate them into the TS Bases and into plant procedures. This approach is consistent with the improved TS format, content, and usage rules, which are intended to avoid inclusion of extraneous requirements that are not related to the proper operation and control of plant systems and equipment.

It is noted that one of the compensatory measures (portable power supplies for RPV pressure control capability) was omitted from the List of Regulatory Commitments provided as Attachment 1 to the March 30, 2010 NMPNS submittal. The List of Regulatory Commitments is revised to include this item, as shown in Attachment 2 to this letter. The TS Bases changes that were included in the March 30, 2010 NMPNS submittal (Attachment 3, INSERT B for TS Bases page B 3.8.1-10) are also revised, as shown in Attachment 3 to this letter.

For certain systems credited in the PRA risk evaluation, there are existing TS operability requirements, as follows:

- HPCS system – TS 3.5.1 (see also the response to RAI-1 above)
- Reactor Core Isolation Cooling (RCIC) system – TS 3.5.3
- Low Pressure Core Spray (LPCS) system – TS 3.5.1
- Residual Heat Removal (RHR) system, low pressure coolant injection (LPCI) function – TS 3.5.1
- RHR system, drywell spray function – TS 3.6.1.6
- RHR system, suppression pool cooling function – TS 3.6.2.3
- RHR system, suppression pool spray function – TS 3.6.2.4
- Standby Liquid Control (SLC) system – TS 3.1.7
- Redundant Reactivity Control system – TS 3.3.4.2
- Offsite power sources – TS 3.8.1

In accordance with the PRA risk evaluation, operability of the above systems is a pre-requisite for entering the extended DG CT. The limiting conditions for operation (LCO) for each of these systems will need to be met without reliance on the Required Actions to satisfy these commitments. The requirements of TS 3.8.1, Required Action B.2, provides assurance that redundant required features that are associated with a division redundant to the inoperable DG are not concurrently inoperable so that a loss of offsite power (LOOP) occurring during the period that a DG is inoperable does not result in a complete loss of safety function of critical systems, including systems listed above (for example, see the response to RAI-1 regarding the HPCS DG).

The proposed TS Bases changes (Attachment 3 of the March 30, 2010 NMPNS submittal) and associated plant procedures will require that the Tier 2 compensatory measures and configuration risk management controls be implemented prior to removing a Division 1 or Division 2 DG from service for planned maintenance utilizing the extended CT (greater than 72 hours and up to 14 days). For an unplanned entry into an extended CT, these measures and controls must be implemented without delay. If one or more of these measures and controls were to be not met while in the extended CT, the condition would be entered into the corrective action program, applicable TS Required Actions would be followed, the risk would be managed in accordance with the NMPNS configuration risk management program (described in Section 3.2.6 of the March 30, 2010 NMPNS submittal), and actions to restore the measure(s) or control(s) would be initiated without delay. This is consistent with the guidance provided in RG 1.177, Section 2.3.7.

RAI-3

In Section 3.2 of the submittal, it is stated that the risk evaluation included consideration of Maintenance Rule controls on the performance of other potentially high risk tasks during a DG outage. The licensee needs to identify exactly what is assumed for availability of other equipment in its risk analyses, and justify its assumptions based on TS or other administrative controls.

Response RAI-3

The calculations for the changes in core damage frequency (CDF) and large early release frequency (LERF) due to the extended DG CT were performed using the PRA zero maintenance configuration and credit for the compensatory measures and configuration risk management controls (as indicated in Sections 3.2.4 and 3.2.5 of the March 30, 2010 NMPNS submittal). The PRA model dominant sequences and model importance measures were evaluated to assure that important equipment was identified and evaluated when a DG is out of service. The risk analysis results determined that the following systems/equipment should be protected (i.e., the system/equipment is confirmed to be operable/available prior to entering the extended DG CT and no planned testing or maintenance activities are scheduled for the duration of the extended DG CT):

- The other two DGs
- HPCS system
- RCIC system
- LPCS system
- RHR system
- SLC system
- Redundant Reactivity Control system
- Offsite power sources
- Diesel engine driven fire pumps (one at each Nine Mile Point unit)

For the above protected systems/equipment, maintenance unavailability was removed in the PRA model. The results of sensitivity analyses, reported in the June 1, 2010 NMPNS submittal (response to Comment 5), further demonstrated that potentially high-risk configurations could exist if protected equipment/systems were out of service concurrent with the extended DG CT. These sensitivity studies confirmed that the restrictions imposed on the protected systems were appropriate.

The March 30, 2010 NMPNS submittal (Section 3.2.4.5) also summarized the results of a sensitivity analysis case for the simultaneous unavailability of certain other systems/equipment that are not protected by compensatory measures. The systems/equipment included in this analysis are listed in the following table:

System	Assumption
Reactor Building Closed Loop Cooling (RBCLC)	One train of RBCLC equipment unavailable
Instrument Air (IAS)	One train of IAS equipment unavailable
Control Rod Drive (CRD)	One train of CRD equipment unavailable
Service Water (SW)	One of six SW pumps unavailable
Turbine Building Closed Loop Cooling (TBCLC)	One train of TBCLC equipment unavailable
Feedwater (FW)	One of three FW pumps unavailable
Electric Fire Pump	Electric Fire Pump unavailable
Uninterruptible Power Supply (UPS)	One of two UPS units unavailable in each of the two trains
DC Power	One of two battery chargers unavailable in each of the two trains.

The analysis conservatively assumed that all of the equipment identified in the above table was unavailable at the same time, even though it is very unlikely that such a plant configuration would be planned or allowed by the configuration risk management program (CRMP). For the remaining available systems/equipment, maintenance unavailability was removed in the PRA model. The results of this sensitivity analysis case (presented in the March 30, 2010 NMPNS submittal) show that the risk increase is minimal.

NMPNS considers it appropriate to treat the Tier 2 compensatory measures and configuration risk management controls as regulatory commitments and to incorporate them into the TS Bases and into plant procedures, as further discussed in the response to RAI-2 above.

RAI-4

Section 3.2.4.2 of the submittal identifies an assumption of a single 14-day DG outage each 24 months for each DG. It is not stated if this is additional unavailability on top of that already assumed in the PRA. Since the proposed 14-day CT may be used to support unplanned outages, if no change is assumed in DG unavailability beyond planned activities, then this assumption would need further justification, or sensitivity analyses should be provided to show increased unplanned unavailability would not invalidate the risk analyses. The licensee needs to identify and justify its assumptions on DG unavailability and provide appropriate sensitivity analyses on these assumptions since the proposed TS do not preclude unplanned unavailability.

Response RAI-4

The risk evaluation for the proposed extension of the DG CT assumes that a 14-day DG outage occurs once per 24-month fuel cycle for each DG. No distinction is made between preventive and corrective DG maintenance. NMPNS practice is to schedule online maintenance activities (both preventive and corrective) so that they are completed within one-half of the TS CT limit.

To assess the impact of unplanned DG unavailability over and above the assumed 14 days, sensitivity analyses were performed considering additional unplanned DG unavailability of 7 days (total of 21 days) and 14 days (total of 28 days) per 24-month fuel cycle. The calculated risk metrics, with compensatory measures and configuration risk management controls implemented, have been calculated for both the Division 1 DG and the Division 2 DG and are summarized in the following table:

Risk Metric	Sensitivity Cases - Additional Unplanned DG Unavailability		Acceptance Guideline Values
	7 Days (21 days total)	14 Days (28 days total)	
ΔCDF_{Avg}	4.3E-07	5.7E-07	< 1.0E-06/yr
$\Delta LERF_{Avg}$	3.3E-08	4.5E-08	< 1.0E-07/yr
$ICCDP_1$*	3.2E-07	4.3E-07	< 5.0E-07
$ICCDP_2$	5.0E-07**	6.6E-07	< 5.0E-07
$ICLERP_1$	2.8E-08	3.8E-08	< 5.0E-08
$ICLERP_2$	3.6E-08	4.8E-08	< 5.0E-08

* Subscripts refer to the Division 1 or Division 2 DG.
** Calculated value is less than 5.0E-07 but is rounded up to the nearest tenth.

All risk metrics effectively meet the acceptance guideline values for the case with 21 total days of unplanned DG unavailability. For the case with 28 total days of unplanned DG unavailability, all risk metrics are within the acceptance guideline values except for the ICCDP for the Division 2 DG, which slightly exceeds the acceptance guideline value. It is unlikely that even 21 days of total DG unavailability (planned and unplanned) would be incurred during any one 24-month period, based on DG maintenance history and availability data.

RAI-5

The licensee has identified 15 regulatory commitments associated with this permanent LAR which are to be incorporated into the TS Bases. The staff requests the following information:

a. *Commitment #2b prohibits planned maintenance or testing activities which could cause a line outage or challenge offsite power availability. It is not clear to the staff what the basis would be for such determinations. The licensee needs to clarify exactly what criteria is proposed to identify activities which are to be prohibited, and as necessary clarify their commitment.*

Response RAI-5a

Commitment number 2b specifically states that no planned maintenance or testing activities will be scheduled in Scriba Substation, the NMP2 115 kV switchyard, or on the 115 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability. Maintenance on substation and switchyard breakers, the 115 kV power supply lines (Lines 5 and 6), the reserve station service transformers (2RTX-XSR1A and B), and associated components is typically performed with the components de-energized for industrial safety reasons, thereby resulting in loss of an offsite power source. Certain testing can be performed without de-energizing equipment (e.g. relay protection circuitry testing); however, such testing could induce a condition or fault that could lead to the loss of an offsite source. Such maintenance and testing activities that could adversely affect the viability (voltage, frequency, stability) or number of available offsite sources will be avoided during an extended DG CT. Section 3.2.6 of the March 30, 2010 NMPNS submittal describes the communications and coordination that takes place between NMPNS and National Grid (the transmission system operator) regarding maintenance and testing activities involving Scriba Substation and the associated overhead transmission lines.

b. *Commitment #2j restricts the use of the extended DG CT for predicted severe weather conditions with potential to degrade or limit offsite power availability. It is not clear to the staff what weather conditions are considered to degrade or limit offsite power, nor is the source of this information identified, or the duration of the prediction (full 14-day CT or other period), nor is the definition of 'degrade' and 'limit' understood in the context of the specifics of this commitment. The licensee needs to clarify the specific method of evaluating weather conditions, and specify what weather conditions would prohibit entry into an extended CT for the DGs.*

Response RAI-5b

In accordance with existing NMPNS procedures, severe weather conditions that could potentially degrade or limit offsite power availability are high winds (sustained winds of greater than 35 mph or gusts greater than 50 mph), tornado, and heavy snow/ice. The terms "degrade" and "limit" refer to conditions that could adversely affect the viability (voltage, frequency, stability) or number of available offsite sources. The DG extended CT will not be entered for voluntary planned maintenance if any of these severe weather conditions are present or if official weather forecasts (e.g., from the National Weather Service) are predicting such conditions to occur. This risk management control is not credited in the PRA risk evaluation performed for the proposed DG extended CT. The LOOP frequency used in the risk evaluation includes weather-related loss of offsite power (LOOP) events and seasonal LOOP frequency variations.

Commitment number 2j (List of Regulatory Commitments, Attachment 1 of the March 30, 2010 NMPNS submittal) is revised to reflect this response, as shown in Attachment 2 to this letter. The TS Bases changes that were included in the March 30, 2010 NMPNS submittal (Attachment 3, INSERT B for TS Bases page B 3.8.1-10) are also revised, as shown in Attachment 3 to this letter.

c. *Commitment #2l identifies that unnecessary transient combustibles will be removed from impacted fire zones. Commitment #2m requires functionality of fire detection and suppression equipment in impacted fire zones, or compensatory measures be implemented per the fire protection program. The licensee needs to clarify how it determines which zones are impacted. Further, it is assumed that the fire protection program always requires compensatory measures for unavailable fire detection and suppression equipment or unnecessary transient combustibles, so it is not clear what additional safety benefit is being proposed from simply following the existing program. The licensee should clarify how this commitment is an enhancement beyond the existing fire protection program requirements which achieves the intent of providing enhanced safety during a DG extended CT.*

Response RAI-5c

The impacted areas are those fire areas in the control building, normal switchgear rooms, the unaffected DG rooms, and cable chase areas where a fire could result in a loss of normal power or emergency power unavailability. NMPNS agrees that the actions stated in commitment numbers 21 and 2m (List of Regulatory Commitments, Attachment 1 of the March 30, 2010 NMPNS submittal) are in accordance with the existing fire protection program requirements. In addition, these two items are not credited in the PRA risk evaluation performed for the proposed DG extended CT. Therefore, NMPNS is deleting items 21 and 2m from the List of Regulatory Commitments and from the TS Bases changes that were included in the March 30, 2010 NMPNS submittal (Attachment 3, INSERT B for TS Bases page B 3.8.1-10). A revised List of Regulatory Commitments is provided in Attachment 2 to this letter, and a revision to the proposed changes to TS Bases page B 3.8.1-10 is provided in Attachment 3 to this letter.

RAI-6

Table 1 identifies industry peer review findings for the NMP PRA peer review against the RG 1.200 Revision 1 endorsed standard for internal events PRA. Two open findings, identified as 5-2 and 6-1, are dispositioned as insignificant impact on the DG CT extension request. However, no technical basis for this is provided in the table to justify that the impact is insignificant. Instead, it is stated that a significant effort would be required which will have to wait until a plant reliability program is developed, and that detailed human reliability analyses will be considered in the future. The licensee needs to provide a technical justification that these open deficiencies do not significantly impact the risk evaluations which are proposed as justification for this license amendment request.

Response RAI-6

Finding 5-2 is against supporting requirement IE-A6, which states: *"When performing the systematic evaluation required in IE-A5, include initiating events resulting from multiple failures, if the equipment failures result from a common cause, and from routine system alignments"*. The peer review noted the following:

> *The NMP2 PRA includes IEs resulting from multiple failures due to common cause. However, routine system alignments contributing to IE frequencies are not included.*

As noted in the response to the peer review comment (Table 1 of the Enclosure to the March 30, 2010 NMPNS submittal), routine alignments are included in the average initiating event frequency development and are included in key system models. Also, since the peer review was completed, support system initiating event fault trees have been added to the model to address important alignments for systems that can cause IEs considered in the PRA.

Certain support system initiating events are evaluated with fault trees to assess insights into the potential causes of these initiating events and compare with generic industry experience (NUREG/CR-6928). The actual fault tree modeling is described in the applicable System Analysis notebook.

The open item for this finding relates to adding additional routine system alignment details, such as half-scram testing, that are not explicitly modeled but are included in IE data development. As noted, these alignments are included in the model used to implement the NMP2 on-line risk model as factors increasing turbine trip frequency. As such, the unique configuration impacting the plant at a specific time is incorporated by operations into the on-line risk model. Based on the results of this model, operators may require that additional compensatory actions be implemented during an extended DG outage or may decide to defer this alignment until after the DG is available. Although modeling these alignments would provide insight into their risk importance, the benefit of modeling this level of detail would primarily be realized in the development and application of a plant reliability model.

Finding 6-1 is against supporting requirement HR-G1. The peer review team noted the following:

> *In some cases the assignment of a conservative screening HEP value may not have been appropriate given the risk significance of the operator action it represents. In particular, the use of a conservative screening value of 1E-02 assigned to the HEP* ***ZHS05**_HSROOMCOL.*

and

> *Operator Fails to open HPCS ROOM Doors and HVAC Duct may not have been appropriate given the risk significance of the HPCS room cooling support system.*

The CDF Fussell-Vesely (FV) value for this action is 0.026 given the Division 1 DG is unavailable, and 0.0365 given the Division 2 DG is unavailable. A detailed human reliability analysis (HRA) would likely result in a measurable reduction in risk contribution; however, a detailed HRA was deferred until the modification to supply fire water to the Division 3 (HPCS) DG as a backup cooling water source is completed and associated procedures are prepared, to assure that the resulting human error probability (HEP) appropriately considers all the factors associated with this action. The 1E-02 value is conservative.

RAI-7

Table 1 identifies industry peer review findings for the NMP PRA peer review against the Regulatory Guide 1.200 Revision 1 endorsed standard for internal events PRA. Finding 1-9 identifies that the NMP PRA model assumes that the failure probability of low pressure system piping, assuming exposure to reactor coolant system (RCS) pressure, is 1.0E-4. The finding was closed based on more detailed evaluation which now varies the failure probability of the piping in the range of 0.05 to 0.003. The licensee is requested to identify the data source for these probabilities, the frequency of interfacing systems loss-of-coolant accidents calculated for NMP, and any mitigation capability credited in the PRA model for these events if a pipe failure occurs.

Response RAI-7

The 0.003 to 0.05 range of pressure boundary rupture failure probabilities is based on a comparison and evaluation of NMP2 piping materials with NUREG/CR-5603. The following provides the results of this evaluation:

System	Limiting Failures	Failure Probability
Low Pressure Core Spray (LPCS)	16-inch pipe	0.003
Residual Heat Removal (RHR) C	18-inch pipe	0.01
RHR A	18-inch pipe + Heat Exchanger	0.05
RHR B	18-inch pipe + Heat Exchanger	0.05

The inter-system loss-of-coolant accident (ISLOCA) initiating event frequency (failure of a normally closed motor-operated valve and check valve) for each of the 6 ISLOCA paths (LPCS, Low Pressure Coolant Injection (LPCI) A, LPCI B, LPCI C, Shutdown Cooling (SDC) Return A, and SDC Return B) is also quantified in the NMP2 PRA as 4.5E-07/year. There are two mitigation success criteria in the NMP2 PRA for these initiating events:

- No Rupture – Leakage is assumed and modeled as a small LOCA outside containment. Makeup from the control rod drive (CRD) and reactor core isolation cooling (RCIC) systems is not credited in the model. The HPCS and LPCS systems eventually fail due to flooding. Feedwater success requires make-up as the condensate storage tank (CST) is not assumed to last 24 hours. The following summarizes impacts on ECCS low pressure injection systems:

Initiating Event	LPCS	LPCI A	LPCI B	LPCI C
ISLOCA-LPCS	Fail (break)	Fail (Jet)	OK	OK
ISLOCA-LPCI A	Fail (Jet) (flooding)	Fail (break)	OK	OK
ISLOCA-LPCI B	Fail (flooding)	OK	Fail (break)	OK
ISLOCA-LPCI C	Fail (flooding)	OK	Fail (flooding)	Fail (break)
ISLOCA-SDC A	Fail (flooding)	Fail (break)	OK	OK
ISLOCA-SDC B	Fail (flooding)	OK	Fail (break)	OK

  If the above injection systems fail, external makeup from sources external to the containment and reactor building are considered. The firewater crosstie to the RHR system is not modeled since it requires local actions in the reactor building. The service water crosstie to the RHR system (RHRSW) is credited as summarized below:

Initiating Event	RHRSW
LPCS	OK
LPCI A	OK
LPCI B	Failed (spatial)
LPCI C	Failed (spatial)
SDC A	OK
SDC B	Failed (spatial)

- Rupture – In addition to the impacts described above for leakage events, feedwater is failed and external make-up is always required for success. Low pressure ECCS is also required for initial success in the short term to allow time for manual external makeup.

The total CDF and LERF for the above ISLOCA initiating events is approximately 6E-08/yr.

RAI-8

The fire PRA portion of the risk analysis is based on the Individual Plant Examination of External Events (IPEEE) fire evaluation. However, the models have not been assessed against the industry consensus standards, and no formal peer review has been done.

a. *Have there been any external reviews of the fire PRA since the IPEEE? If so, describe the scope and findings of the reviews, and the resolution of the identified issues for this application.*

Response RAI-8a

No external reviews of the NMP2 fire PRA have been performed since the IPEEE was submitted in 1995. The IPEEE fire analysis was reviewed by a team from Energy Research, Inc., on behalf of the NRC. The results of that review are documented in Report ERI/NRC 95-513 enclosed with the NRC safety evaluation that was issued from the NRC (D. S. Hood) to Niagara Mohawk Power Corporation (J. H. Mueller) dated August 12, 1998.

b. *What internal reviews have been done to the fire PRA since the IPEEE? Similarly describe the scope and findings of the reviews, and the resolution of the identified issues for this application.*

Response RAI-8b

No comprehensive reviews of the fire PRA have been performed since the IPEEE, since fire events have been considered to be conservatively treated in the IPEEE. Internal reviews of the fire PRA assumptions have occasionally been performed to support specific applications, such as enforcement discretion requests and extended power uprate. A more detailed internal review was performed for the DG completion time extension application, with the results presented in Attachment 2 of the NMPNS submittal dated June 1, 2010.

c. *The discussion on conformance to the high level technical requirements in RG 1.200 (Attachment 2 of the June 1, 2010, supplemental submittal) identifies reviews conducted to confirm the fire PRA model is current with regards to plant modifications and cable routes. It is not clear if maintaining the fire PRA model since the IPEEE has been an ongoing process at NMP, or if the fire PRA model has been "caught up" by reviewing historical records to support this application. The licensee is requested to clarify its administrative controls for the fire PRA model.*

Response RAI-8c

No comprehensive reviews of the fire PRA have been performed since the IPEEE, since fire events have been considered to be conservatively treated in the IPEEE. A detailed internal review was performed for the DG completion time extension application, with the results presented in Attachment 2 of the NMPNS submittal dated June 1, 2010. This review considered changes to plant design and operation that have occurred since the IPEEE was performed (i.e., the fire PRA model has been "caught up").

d. *The discussion on conformance to the high level technical requirements in RG 1.200 (Attachment 2 of the June 1, 2010, supplemental submittal) identifies how various fire PRA development tasks were completed. It is not clear in all cases what items discuss how the IPEEE was originally developed, and what items discuss new updated evaluations conducted to support this application. The licensee is requested to identify updates and new analysis conducted to support this application, and describe internal and external reviews conducted to assure the technical adequacy of such analyses.*

Response RAI-8d

As noted in the June 1, 2010 NMPNS submittal (response to Comment 1), Attachment 2 to that submittal summarized an assessment comparing the current NMP2 internal fire PRA model to the technical elements outlined in Section 1.2.4 of RG 1.200, Revision 2, following the format of Table 5 of the RG. In those cases where the current internal fire PRA model is not entirely consistent with the technical elements of RG 1.200, Revision 2, assessments that include sensitivity studies have been performed to demonstrate that the model is still adequate for application to the proposed extension of the CT for an inoperable DG. The following summarizes the additional evaluations that were performed to support the proposed amendment:

1. Modifications were reviewed to ensure confidence that there were no cable and/or equipment changes that might impact the evaluation.
2. All compartments were re-evaluated with a lower screening value of 1E-7 for CDF.
3. The detailed analysis of compartments that did not meet this screening was reviewed to ensure that the detailed screening was still reasonable. In response to RAI 11.a, a screening value of 1E-8 was applied to show that the conclusions of the original submittal are unchanged.
4. Sensitivity of potential human error probability (HEP) impacts was considered (identified as a gap), with the results presented in Attachment A2-D of the June 1, 2010 NMPNS submittal.
5. The multiple spurious operation (MSO) evaluation was reviewed for potential significant scenarios (identified as gap), with the results presented in Attachment A2-C of the June 1, 2010 NMPNS submittal.

All of this work, including reviews, has been conducted using in-house resources, with outside consultant support.

e. *In its review of the IPEEE, the staff identified concerns with regards to optimistic recovery probabilities for control room fire scenarios, unrealistically low heat release rates for control room cabinets, and unrealistic fire detection times. No changes or revised evaluations were made by the licensee in response. The licensee needs to discuss these issues with respect to their relevance to this application.*

Response RAI-8e

Optimistic Recovery Probabilities

There are three general operator actions in the PRA model that consider operator reliability in response to fires in the control room:

- **ZHRA1** (1E-03) is used for cases where the operators remain in the control room with automatic high pressure injection successful and there is no requirement to recover equipment (e.g., AC power) from outside the control room. There is ample time for the operators to ensure long term inventory control and heat removal. Failure of this action is modeled as going directly to core damage. This value is judged to be realistic to conservative.

- **ZHRA2** (1E-02) is used for the following types of events:
  (1) Operators remain in the control room, but high pressure injection has failed or equipment recovery (e.g., AC power) is required from outside the control room. The key action for this case would be emergency depressurization and ensuring that low pressure injection is successful. The 1E-02 value is more than an order of magnitude greater than operator action **ZOD01** used for internal events.
  (2) Operators abandon the control room, with RCIC success. There is ample time for operators to ensure long term inventory control and heat removal. The 1E-02 value is based on increasing ZHRA1 by an order of magnitude and is judged to be realistic to conservative.

- **ZHRA3** (0.1) is used for the following types of events:
  (1) Operators remain in the control room, high pressure injection is unavailable, and equipment recovery is required from outside the control room.
  (2) Operators abandon the control room and high pressure injection has failed.

  The key actions for the above two cases are to either restore high pressure injection or emergency depressurize and inject with low pressure injection. Again, this value is judged to be realistic to conservative.

Unrealistic Heat Release Rates and Detection Times

Heat release rates were not an important consideration in the IPEEE control room fire analysis and based on more recent guidance in Appendix L of NUREG/CR-6850, the probability that a fire in the main control board propagates beyond the ignition source is approximately 5E-03. The total frequency of a fire in the main control board, based on EPRI 1019259 (NUREG/CR -6850, Supplement 1), is 8.24E-04. Considering the combination of this frequency with the propagation probability (5E-03) indicates that the scenarios presently modeled from the IPEEE are reasonable or conservative. The control room is continuously manned, with detection likely to be immediate.

f. The fire PRA assumes the plant is configured as per its design basis with regards to proper separation of plant areas, cabling, etc. The licensee needs to identify any known deficiencies in fire protection separation requirements, and disposition any such items with regards to this application.

Response RAI-8f

There are no known deficiencies in fire protection separation requirements. Deficiencies in conformance with existing fire protection separation requirements would be addressed in a timely manner in accordance with the NMPNS fire protection program and the corrective action program. The requirements of Condition 2.F of the operating license and the NMPNS design change process requirements would apply to proposed design changes affecting fire protection separation requirements.

RAI-9

The fire risk evaluation of the configuration of one EDG out of service has not been described in sufficient detail in the application.

a. *It is stated that only fires which cause a loss of offsite power are relevant to this application. With one EDG out of service, increased risk would result from reliance upon the remaining operable safety train of equipment in the event that a fire results in offsite power being lost to the electrical bus normally powered by the unavailable EDG (i.e., not necessarily a total loss of offsite power). This can occur on either a total loss of offsite power or from a loss of offsite power to the one electrical bus, and such loss would be unrecoverable without subsequent repairs. It is not clear whether both of these scenarios are evaluated in the fire PRA used for this application. Further, it appears from the staff review of detailed results, provided by the licensee in its June 1, 2010, supplemental submittal, that the PRA results may only consider fires which impact both offsite power and additional components, and neglect fires which only impact offsite power. The licensee needs to clarify the scope of scenarios considered for this application and justify exclusion of scenarios, if applicable.*

Response RAI-9a

Fire event scenarios involving both a total loss of offsite power and partial loss of AC power to a single electrical division were evaluated in the fire PRA used for the proposed amendment. Also included were fire scenarios that only cause a loss of offsite power. No scenarios were excluded. This can be seen in Table A2-3 of the June 1, 2010 NMPNS submittal, in the descriptions provided in the "Impacts" column. See also the response to RAI-11a.

b. *As identified in Attachment 2 of the supplemental submittal, fire scenarios may be screened below a threshold of 1E-6 per year core damage frequency (CDF). For a specific application like the analysis of risk for an EDG outage, some screened scenarios may become more significant. If screening of scenarios was performed for the baseline PRA, discuss the review of screened fire scenarios to assure that the configuration-specific risk is not underestimated.*

Response RAI-9b

Although a CDF screening value of less than 1E-06 was used in the original IPEEE, an updated analysis using a CDF screening value of 1E-07 was performed for the extended DG CT risk evaluation. The results, provided in Table A2-1A of the June 1, 2010 NMPNS submittal, provided the updated CDF values associated with each compartment using the latest CAFTA model for the same impacts and frequencies. Using a CDF screening value of 1E-07, several previously unscreened compartments screened out and 3 new compartments were added (were unscreened). These new events were determined to be non-consequential based on the detailed evaluation provided in Attachment A2-B of the June 1, 2010 NMPNS submittal. The fire CDF values were lower in all cases.

To address the potential that these screened scenarios underestimated the configuration-specific risk associated with an unavailable DG, a lower CDF screening value of 1E-08 was applied to compartments with AC power impacts. As a result, 3 additional fire zones were unscreened. Their associated fire initiating events were updated and the risk measures used to justify the proposed amendment were recalculated. There was a small increase in some of the risk measures; however, they all remained well below the acceptance criteria. The detailed results of this lower screening are discussed in the response to RAI-11a.

c. *It is not clear if recovery of offsite power following loss due to fire effects is being credited in the analysis; clarify how the PRA addresses post-fire repairs and recovery of plant equipment in general, and offsite power supplies in particular.*

Response RAI-9c

Recovery of offsite power following a loss due to fire effects is not credited; however, recovery of equipment not affected by the fire is credited, including recovery of the non-fire-affected DG.

For non-fire events, AC power recovery is credited as in the baseline PRA, except that the DG that has entered the extended CT is assumed to be not recovered (as noted in Section 3.2.4.2 of the March 30, 2010 NMPNS submittal).

d. *A critical aspect of fire PRA development involves the physical location of cables. One approach when the locations are mostly unknown employs an "exclusion" assumption, that cables are assumed to be located anywhere except where they are known not to be present. Some cable routing information may not be readily available, and assumptions as to the location of such cables may be made to simplify the data collection to support the PRA development. Are such assumptions employed in the NMP PRA development? If so, describe and justify these assumptions, and characterize their significance to this specific application.*

Response RAI-9d

No exclusion assumptions involving the physical location of cables were used in the development of the fire PRA. All exclusions have a basis such that they are not considered an assumption. The most important exclusion impact in the IPEEE includes the use of 10 CFR 50 Appendix R safe shutdown analyses. As an example, when the Appendix R analysis for a given fire area indicates that Division 2 and 3 equipment are available (safe shutdown divisions for the area), the PRA analysis also excludes these impacts in the initial screening. On the other hand, if the Appendix R analysis indicates that Division 2 and 3 equipment may be affected, then the PRA analysis assumes all Division 2 and 3 functions are affected in the initial screening. If the area could not be screened, then the spatial orientation of cables in the compartment was examined to perform a more realistic analysis. This included both review of the cable database and area walkdowns. In some cases, a walkdown alone confirmed that impacts initially assumed could be excluded. As an example, the operator's lunch room and the shift supervisors office and training room were identified as being part of the Appendix R safe shutdown areas and were assumed to contain divisional impacts during the initial screening. Most of these initially assumed impacts were excluded based solely on walkdowns.

e. *Describe any plant-specific features of the NMP design related to detection, suppression, and mitigation of fires which are credited in the fire PRA. Examples of such items would be credit for water curtains, incipient detection, credit for prompt detection and/or suppression based on administrative controls, or other items which may be relevant to the risk analyses supporting this amendment request.*

Response RAI-9e

No water curtains or incipient detection were credited in the fire PRA. Credit for detection and/or suppression that is relevant to risk analyses supporting the proposed amendment is as follows:

- Fire Area 26 (Control Room) – Prompt detection and suppression is implicitly included in the control room evaluation based on the fact that operators continuously man the room. The control room has automatic halon suppression in the subfloor.
- Fire Area 88 (Corridor El 261 of Control Building) – A portion of this area has automatic cable tray water suppression, which is credited in the model for initiating event %FA88B. Suppression failure is conservatively assumed to cause all impacts identified in this portion of the area.
- Fire Areas FA16 and FA17 (Division 1 Cable Chases) – These areas have automatic cable tray water suppression, which was credited in the model as well as screening. Event %FA16A models successful suppression and event %FA16B models suppression failure.
- Fire Areas FA18 and FA19 (Division 2 Cable Chases) – These areas have automatic cable tray water suppression, which was credited in the model as well as screening. Event %FA18A models successful suppression and event %FA18B models suppression failure.
- Fire Areas FA34 and FA35 (Reactor Building) – These areas have automatic cable tray suppression, which was credited in screening these areas.
- Fire Areas FA51, FA52, FA78, and FA79 (West and East Normal Switchgear areas); and Fire Zones 333XL and 336XL (Division 1 and 2 Standby Switchgear rooms) – These rooms have a CO_2 total flooding suppression system. Manual suppression is credited in the standby switchgear rooms for some scenarios where propagation is a concern. Manual suppression is credited in the normal switchgear areas before a complete loss of offsite power occurs as a result of the fire.
- Fire Areas FA60 and 61 (Service Water Pump areas) – There is detection, but no automatic suppression, in these areas. No credit is taken for prompt suppression.

- Fire Zones 338NZ and 343NZ (Remote Shutdown A and B rooms) – There is detection, but no automatic suppression, in these rooms. No credit is taken for prompt suppression since these are small rooms and the impacts are concentrated within a single cabinet.

f. *Describe how fire growth and propagation are treated in the NMP fire PRA – specifically identify and justify any assumptions applied, and any fire modeling and codes used.*

Response RAI-9f

The NMP2 Fire PRA utilized the methodology in EPRI's "Fire-Induced Vulnerability Evaluation (FIVE)," including Revision 1 dated September 29, 1993, and NSAC/178L, "Fire Events Database for U.S. Nuclear Power Plants," Revision 1, January 1993. The FIVE methodology was used extensively for information collection activities, fire hazard analyses, walkdowns, fire growth and propagation analyses, fire detection and suppression assessment, and other fire IPEEE tasks.

The extent of the detailed modeling was minimized by employing a generic modeling of typical combustibles (electrical cabinets, motors, transients, etc.). This allowed a screening to be employed during walkdowns of each fire compartment. Using this methodology, only scenarios that offered the potential for concern were identified and modeled. Walkdown screening eliminated the need for detailed modeling in the majority of compartments. Modeling was also performed for the purpose of evaluating detection and suppression system response in a limited number of areas to support the detailed screening process.

Generic evaluations were performed for electrical cabinets, transformers, electric motors and transients. "In-the-Plume" evaluations for center, corner, and wall fire locations were performed for both damage and ignition scenarios and also for radiant exposure damage scenarios. These evaluations provided critical separation distances or zone of influence distances that were used to evaluate the potential involvement of adjacent combustibles from the various ignition sources, as identified during plant walkdowns of each fire compartment.

Assumptions Applied

NMP2 utilizes IEEE 383 qualified cable; therefore, a damage temperature of 700°F and an ignition temperature of 932°F were used in the evaluations. These values were selected based on guidance in the EPRI FIVE document and are considered conservative based on a review of the actual cable types specified and installed at NMP2. The heat release rate for an electrical cabinet fire of 65 Btu/sec was assumed based on evaluation of electrical cabinet fires with qualified cable documented in tests conducted at Sandia National Laboratory (NUREG/CR-4527). The heat release rate for non-oil filled transformers of 65 Btu/sec was also used since they are essentially windings of qualified cable. Similar to transformers, the heat release rate and worksheets for electric cabinets were used for screening fire ignition by electric motors. A significant variation in transient fire heat release rates can occur based on the types of transients. In most plant areas, a trash fire as opposed to an oil fire is the appropriate transient fire consideration. The most severe transient trash fire in the FIVE report is a 32 gallon trash bag fire. However, the test that provided the heat release rate for the 32 gallon trash bag fire used binned yard waste (eucalyptus leaves). This is not considered representative of nuclear plant trash. For screening purposes, a transient fire heat release rate of 145 Btu/sec with total heat content of 130,500 Btu was selected based on a review of more representative transient fire tests. The EPRI 32 gallon trash bag fire was used for analysis purposes in the specific evaluation of detection and suppression system responses.

The appropriate heat release rate was used repetitively in FIVE Worksheet 1 for various target heights above the fire source until the critical temperature rise at the target was equal to the damage temperature of 700°F or the ignition temperature of 932°F. The process was repeated for fire location factors for corner, wall, and center. Similarly radiation distances were evaluated using Worksheet 3.

The following table summarizes critical heights used for damage and ignition. Also, the heat release rate (HRR) in BTU/sec and total heat released in BTUs are provided for each source. This table was used in the detailed analysis of those areas that did not screen out during the initial screening analysis.

Pre-Calculated Critical Heights (feet) for Damage and Ignition									
SOURCE	**USER**		**DAMAGE**				**IGNITION**		
			Plume			**Rad.**	**Plume**		
	HRR	**Btu**	**Center**	**Wall**	**Corner**		**Center**	**Wall**	**Corner**
Electrical Cabinets	65	58500	3.8	5.0	6.6	1.4	3.1	4.1	5.4
Transformers	65	58500	3.8	5.0	6.6	1.4	3.1	4.1	5.4
7 1/2 HP Motors	65	10000	3.8	5.0	6.6	1.4	3.1	4.1	5.4
25 HP Motors	65	32500	3.8	5.0	6.6	1.4	3.1	4.1	5.4
Transients	145	130500	5.3	6.9	9.1	2.2	4.3	5.7	7.5

g. *Fires occurring in the main control room, or other plant areas, which can lead to evacuation of the control room (including evacuation due to loss of functionality, not necessarily habitability, especially for ex-control room fires), have sometimes been conservatively modeled in fire PRAs. This can mask the risk importance of out-of-service equipment if such fires are conservatively assumed to be unmitigatable. In addition, some plants only protect a single safety train of equipment for remote shutdown, so if a control room fire occurred during maintenance on that specific train of equipment, mitigation may not be available. It is assumed that a control room fire could cause a loss of power to a bus during the DG outage. Identify and describe the impact of such fires on the configuration-specific risk analyses for the DG outage configurations, addressing any conservatisms in assumptions, and impacts due to plant design of remote shutdown capability.*

Response RAI-9g

At NMP2, there are two remote shutdown panels (separate rooms), one for each safe shutdown division. Also, loss of a train due to fire in the control room does not mean that recovery is not possible from outside the control room. With regard to this application, the key control room scenarios are included because, during the IPEEE, it was recognized that loss of AC power scenarios were the most important. Conservatisms in the analysis include the following:

- Probability of control room abandonment is 0.1 for "less significant" control room fires (initiating event %FCR0), and 0.5 for all other control room fire initiating events. These probabilities are judged to be conservative compared to what updated analyses would show based on more recent guidance in NUREG/CR-6850.
- Less significant fires are assumed to result in loss of the feedwater system and the main condenser.

The following four control room fire initiating events are modeled in the Fire PRA:

Initiating Event	Control Room Fire Description
%FCR0	This initiating event represents "less significant" fires where it is likely that the operators will remain in the control room. However a probability of the operators leaving the control room is considered in the analysis [probability of 0.1]. No credit is taken for condensate and feedwater systems continuing to provide RPV level control.
%FCR1	A fire in panel 852 is assumed to result in a loss of offsite power to Division 1 and 2. A non-recoverable loss of offsite power is assumed to occur at the Division 1 and 2 switchgear. Division 3 (HPCS) is assumed to be lost and not recoverable (not recoverable from the remote shutdown panels). Based on these initial conditions, it is assumed that operators can recover from the control room if the RCIC system and at least one DG is available.
%FCR2	A fire in panel 852 is assumed to result in a non-recoverable loss of offsite power at the Division 1 switchgear. Division 1 and 2 switchgear are assumed lost due to breakers tripping. Based on these initial conditions, operators have to recover AC power from outside the control room because both Division 1 and 2 switchgear are assumed to be lost. Division 3 (HPCS) is not affected by this fire and RCIC is available from panel 601.
%FCR3	A fire in panel 601 results in total loss of service water. The operators have to recognize the loss of service water event, which will require RCIC interlocks to be bypassed, and eventually service water will need to be recovered to provide decay heat removal or containment venting will be required. If RCIC fails, the operators will have to depressurize the RPV and open ECCS pump room doors in the long term to provide room cooling.

Contributions of these control room fire initiating events to CDF and LERF are provided in Table A2-3 of the June 1, 2010 NMPNS submittal.

RAI-10

Given a loss of offsite power and failure of emergency DGs (station blackout), describe the assumptions for equipment credited in the PRA internal events model for continued core cooling. Include in your response any operator actions necessary, assumptions on environmental conditions given a station blackout, water inventories and makeup sources, and mission times. Does the PRA assume that core damage can be prevented even if AC power is not restored, or is offsite power recovery or DG repair necessary?

Response RAI-10

The following success states for continued core cooling for a station blackout event are available in the NMP2 PRA for the 24-hour mission time without requiring recovery of offsite power or a Division 1 or 2 DG:

- HPCS injection with long term containment heat removal – Alignment of fire water to the Division 3 (HPCS) DG allows the HPCS system to provide reactor vessel inventory control. With the inventory in the condensate storage tank (CST) and the suppression pool, the HPCS system can operate successfully for 24 hours. Operator actions associated with HPCS system operation include aligning fire water to the HPCS DG (ZHS03), protecting the HPCS DG from overheating (ZHS04, shut down DG), and in the longer term ensuring the HPCS pump room is cooled (ZHS05, open pump room doors and HVAC ductwork). In the very long term, containment heat removal is assumed to be required. Either the 60 kVA portable generator (ZPAC1 and ZCV05 operator action) or the portable power supplies (ZCV06 operator action) can be utilized to open containment vent valves providing long term containment heat removal.

- RCIC injection followed by fire water injection and long term actions to keep safety relief valves (SRVs) open and provide containment heat removal – The RCIC system must successfully operate for several hours to allow decay heat reduction and time for operators to align firewater injection. With the inventory in the condensate storage tank (CST) and the suppression pool, the RCIC system can operate successfully for much longer than several hours; however, long term RCIC system operation is not credited due to suppression pool and containment heat-up. Operator actions associated with RCIC system operation include bypassing the high RCIC area temperature trip (ZIC02) and opening the RCIC pump room doors (ZIC04) to provide room cooling.

  Given RCIC system success, the fire water system can be aligned to the RHR-B loop for injection (ZS102 operator action). Injection via the fire water system is supported by an unlimited water supply (Lake Ontario) and can be performed using either the NMP2 or NMP1 diesel driven fire water pump. In addition, emergency reactor vessel depressurization (ZOD01) is required to support fire water injection. In the long term, DC power and nitrogen makeup to the SRVs is assumed to be required in order to achieve the 24-hour mission time for injection. This requires using the 60 kVA portable generator (ZPAC1 operator action) to provide DC power and using the portable power supplies to allow opening of containment isolation valves to restore nitrogen supply to the SRVs (operator action ZOSVL1). In the very long term, containment heat removal is assumed to be required. The 60 kVA portable generator (ZPAC1 and ZCV05 operator action) can be utilized to open containment vent valves providing long term containment heat removal.

An additional reactor vessel inventory control success path that is modeled without recovering offsite power or one of the Division 1 or 2 DGs involves cross-connecting the Division 3 DG to either the Division 1 or Division 2 emergency switchgear to power a service water pump for Division 3 DG cooling, an RHR pump, DC power, and instrumentation (operator actions ZHS01, ZHS02 and ZHS07, depending on timing). However, this is only credited as providing inventory control and a success state is presently not credited in the model unless offsite power or one of the DGs (Division 1 or 2) is recovered to support containment heat removal.

RAI-11

The licensee provided detailed evaluations of what is assumed to be the baseline fire PRA evaluation in Attachment A2-B of its June 1, 2010, supplemental submittal. The NRC staff has the following general questions about these evaluations.

a. *The NRC staff review noted that a screening criteria of E-7/year CDF is repeatedly applied to justify excluding numerous fire scenarios from consideration. It is not clear from this document whether the screen includes consideration that a DG is out of service. Further, the application delta-CDF is identified as 2.9E-7/year (Section 3.2.4.4 of Enclosure to March 30, 2010, submittal). Screening numerous fire scenarios at 1E-7/year when the application change in risk is only a factor of three more likely would not appear to be appropriate and could result in underestimating the change in risk. The licensee should justify use of the 1E-7/year CDF screening criteria applied for this application.*

Response RAI-11a

The screening does not include consideration that a DG is out of service. The screening risk assessment is based on the impact a fire has on a specific compartment using the average maintenance unavailability baseline PRA.

To address the potential that the screened scenarios underestimated the configuration-specific risk associated with an unavailable DG; a lower CDF screening value of 1E-08 was applied to compartments with AC power impacts. As a result, 3 additional fire zones were unscreened (versus using the 1E-07 screening value). These 3 zones and their associated initiating events are listed below.

Area	Zone	Description	Initiating Event	Impacts
16	321NW	Division 1 riser area	FA16A	Fire in FA16 vertical trays - Loss of Div. 1 AC and RCIC
			FA16B	Fire in FA16 vertical trays (suppression failure) - Loss of offsite power, Div. 1 AC, and RCIC
17	322NW	Division 1 cable routing area	FA333XL	Loss of offsite power and Div. 1 AC
53	603NZ	Battery rooms	FNSGR	Loss of offsite power

The initiating event frequencies for the 3 above-listed zones were conservatively increased by a factor of 5 and included in the calculation of frequencies of their associated or similar/bounding initiating events. The model was updated using the new initiating event frequencies and the risk measures used to support the extension of the DG completion time were recalculated. The results are listed below. There was a small increase in some of the risk measures; however all are still well below the acceptance criteria.

Updated Risk Measures Including 3 New Fire Zones (Base Case - with Compensatory Actions)			
Risk Metric	**LAR**	**Updated**	**Acceptance Guideline Values**
ΔCDF_{ave}	2.9E-07	3.7E-07	<1E-06/yr
$\Delta LERF_{ave}$	2.2E-08	2.5E-08	<1E-07/yr
$ICCDP_1$	2.2E-07	2.5E-07	<5E-07
$ICCDP_2$	3.3E-07	4.6E-07	<5E-07
$ICLERP_1$	1.9E-08	1.8E-08	<5E-08
$ICLERP_2$	2.4E-08	3.0E-08	<5E-08

b. *The NRC staff review of this information identified assumptions made in the detailed analyses, but the justification for these assumptions was not discussed. Specifically:*

- *A 10% "spatial factor" was applied to the initiating event frequency for a fire near vertical trays (Division 1 Cable Chase West).*
- *Cables and conduit within 5 feet of a vertical cabinet were considered impacted by the plume, and within 1.5 feet were considered impacted by radiation heat transfer.*

The licensee should identify all unique fire modeling assumptions made in the PRA, and provide appropriate references or justification for these assumptions.

Response RAI-11b

No unique modeling assumptions were made; the assumptions made are typical of those made in fire PRAs. Regarding the two identified items:

- 10% spacial factor – The 10% assumption is based on total compartment area and the area of interest that could cause the critical scenario. When considering the floor area where fires could potentially impact cables in vertical trays or conduits near the floor, it was judged that 10% of the floor area could potentially cause some damage before suppression would occur.

- Cables and conduit within 5 feet of a vertical cabinet – The basis for this assumption is from the FIVE methodology. The table provided in the response to RAI-9f summarizes critical heights used for damage and ignition.

c. *Many fire areas are dispositioned by identifying that the significant cables are located high in the overhead. The licensee needs to describe how the fire PRA treats hot gas layer development, and justify the criteria applied to conclude that the overhead location of cables assures these cables are not damaged by a hot gas layer.*

Response RAI-11c

Hot gas layer development with damage to targets was not identified as a concern during the IPEEE walkdowns (e.g., size of area, height of ceiling versus targets, etc.). For example, high ceilings ensure that cabinets near the floor are not damaged by a hot gas layer and qualified cables in combination with distance between the cables and the ceiling ensure that that cables are not damaged. The following provides further discussion for key areas

- Fire Area 88 (Corridor El 261 of Control Building) – This area has a high ceiling with automatic suppression in the cable trays. Total impact of area is assumed and modeled if suppression fails.
- Fire Areas FA16 and FA17 (Division 1 Cable Chases) – This area has a high ceiling with automatic suppression in the cable trays. Total impact of area is assumed and modeled if suppression fails.
- Fire Areas FA18 and FA19 (Division 2 Cable Chases) – This area has a high ceiling with automatic suppression in the cable trays. Total impact of area is assumed and modeled if suppression fails.
- Fire Areas FA34 and FA35 (Reactor Building) – Each floor elevation is a very large area, ceilings are high, some ceilings have open grating, open pipe chases, and open hatches to the refueling floor level, etc. In addition, the cable trays are not routed on or near the ceilings; there is sufficient depth from the ceilings to the cable trays for a hot gas layer to propagate up to a higher level through these openings without impacting cables. Also, development of a hot gas layer at the top of the reactor building, above the refueling floor level, will not impact any PRA components.
- Fire Areas FA51, FA52, FA78, and FA79 (West and East Normal Switchgear areas); and Fire Zones 333XL and 336XL (Division 1 and 2 Standby Switchgear rooms) – These rooms are large (though not as large as the reactor building). The ceilings are high and cable trays are not routed at the ceiling. The maximum impact is assumed and modeled if the fire is not suppressed; therefore, long-term development of a hot gas layer is not relevant.
- Fire Areas FA60 and 61 (Service Water Pump areas) – The service water pumps are in pits and the ceiling is very high. Hot gas layer impact is not credible.
- Fire Zones 338NZ and 343NZ (Remote Shutdown A and B rooms) – Total impact in each room is assumed and modeled without credit for suppression.

RAI-12

The licensee provided detailed evaluations of what is assumed to be the baseline fire PRA evaluation in Attachment A2-B of its June 1, 2010, supplemental submittal. In its review of this attachment, the NRC staff has additional clarifications needed for specific fire areas to support its evaluation:

a. *It is specifically stated by the licensee that the completeness of the main control board fire scenario development is "lacking," but then states that since a single panel, designated as number 852, is the most important for this application based on offsite power and DG controls being on this panel. Describe how the remainder of the main control board was evaluated for this application and determined to be insignificant such that no further risk evaluations were needed to support the DG extended CT analysis.*

Response RAI-12a

Only control room panel 852 impacts AC power; the other main control board panels do not affect AC power availability. Loss of the service water system was associated with panel 601, and loss of the feedwater system and the main condenser were assumed for all other main control room panels and cabinets. These assumptions provided a reasonable set of scenarios to show that the risk impact from this application is not significant.

What was meant by the term "lacking" in Attachment A2-B of the June 1, 2010 NMPNS submittal is that current fire PRA standards require more detailed scenarios to be modeled for each panel. However, the present fire model, though lacking detail, captures the support systems that are most important for the extended DG CT risk evaluation such that future fire PRA updates will not impact the conclusions.

b. *Two plant areas, designated as the Shift Supervisors Office and the Operators Lunch Room, are separately dispositioned from the Control Room. Are these separate fire areas in the plant with appropriate fire barriers which preclude fire spread to adjacent rooms? If not, justify the implicit assumption that fires cannot spread to adjacent rooms.*

Response RAI-12b

The operator's lunch room is a separate fire area (FA76) outside the control room (FA26) and across a corridor from the control room; therefore, propagation into the control room is very unlikely. The Shift Supervisor's Office is a separate fire zone (373NZ) within the same fire area (FA26) containing the control room. Since the control room is continuously manned and the Shift Supervisor's Office is visible from the control room area, immediate response is likely. Both the operator's lunch room and the Shift Supervisor's Office are provided with smoke detection. See the NMP2 Updated Safety Analysis Report (USAR), Appendix 9A, Section 9A.3.1.2.5.2 and Figure 9A.3-7.

c. *Fire area FA88 is identified as being "very long" and reference is made to a simplified diagram. The NRC staff is assuming that this refers to the diagram imbedded on page 21 of Attachment A2-B. The diagram has no dimensions, and reference is made to shaded areas even though there is no apparent shading on the diagram. Separate evaluations of different parts of this fire area are presented, but there is no basis identified as to why a fire starting in one area is precluded from spreading to adjacent areas. It is further identified that a division 1 DG cable is located "at the opposite end of Section A from where FA88B starts," and then concluding that damage to this cable is unlikely. The NRC staff is unable to confirm apparent licensee assumptions regarding the physical layout of this area such that cable damage to multiple components from single fires is not credible. The licensee needs to provide more specific technical justifications for its assumptions regarding the separation of cables and potential for fire spread in this area.*

Response RAI-12c

Figure 12c-1 is a scaled physical layout drawing that provides a better description of the arrangement and location of fire area FA88. This area is located on elevation 261' of the Control Building and consists of a corridor that passes around the perimeter of the Division 1, Division 2, and Division 3 (HPCS) standby switchgear rooms. As noted in Attachment A2-B of the June 1, 2010 NMPNS submittal, the portion of this area designated as FA88A has lower ceilings (about 17 and 20 feet) and is provided with smoke detection but no automatic suppression. The portion identified as FA88B has higher ceilings (about 40 feet) and is provided with smoke detection and automatic cable tray water sprays.

As noted on Figure 12c-1, the conduit (2CL511GD) containing the Division 1 DG cable is located at the end of FA88A furthest from FA88B. Two corners and a distance of about 95 feet separate conduit 2CL511GD from FA88B. This separation, along with the detection and suppression capabilities provided in FA88B, support the conclusion that it is incredible to have a fire in FA88B propagate into FA88A and impact the Division 1 DG cable in conduit 2CL511GD.

d. *For fire area FA19, it is stated that electrical cabinet fires dominate the calculated frequency of fires, and that the contribution from causes external to cabinets is much less. It is concluded based on this distribution of causes that an order of magnitude reduction in the results is justified. The licensee needs to discuss in more details how this conclusion is reached.*

Response RAI-12d

The subject statement from Attachment A2-B of the June 1, 2010 NMPNS submittal, under the discussion for the Division 2 Standby Switchgear Room (FA19, 336XL) is:

> "The frequency of a fire in this zone is dominated by electrical cabinet fires. The contribution from other causes (i.e., welding, transient, ventilation fans, junction box splices) external to the cabinets is much less frequent. This alone provides over an order of magnitude reduction in the screening analysis results."

This statement was intended to indicate only that the frequency of fires in this zone due to causes other than cabinet fires (i.e., welding, transient, ventilation fans, junction box splices) is significantly less than the frequency of cabinet fires. A discussion of the calculation of fire frequency for this room is provided in later paragraphs. Please refer to the discussion beginning on page 26 of 46 (bottom) of Attachment A2-B, and continuing on page 27 of 46. As noted therein, the calculated fire frequency in this room considered all causes.

e. *For fire area FA19, it is stated that based on judgment, fires cannot impact both Division 2 AC and/or DC power and also impact two HPCS conduits on the wall of the room. The discussion then goes on to specifically identify two locations where such concurrent impacts are possible, but then dismisses the impact based on a statement that the CDF "would be" less than 1E-7/year. Can fires impact both HPCS and AC/DC division 2 power? Have risk calculations been made to confirm the CDF is below 1E-7?*

Response RAI-12e

As discussed in Attachment A2-B of the June 1, 2010 NMPNS submittal, the detailed evaluation performed for FA19 concluded that the CDF for fire events that impact Division 2 AC or DC power and also Division 3 (HPCS) would be less than 1E-07/yr even without taking credit for suppression. Thus, these fire impacts are not modeled. Both HPCS conduits are about 12 to 15 feet above floor level on one wall. At each end of the room, one HPCS conduit passes near a cable tray containing normal AC power cables. The evaluation performed included the following considerations:

- A transient fire would have minimal direct impact on the HPCS conduits since the distance from the floor to the conduits is larger than the critical distance for a transient fire on a wall (see the table provided in the response to RAI-9f).
- A transient fire impacting intervening combustibles involving cables, with propagation to HPCS conduits (2CX500PA1 and 2CX500PE), is unlikely. The first cable tray off the floor (2TX565N) is about 10 feet above the floor. This cable tray would have to ignite and propagate to the HPCS conduits that are about 3 feet above this tray. A transient fire analysis indicates that this closest cable tray would not exceed the ignition temperature of 932°F for IEEE 383 qualified cable (see the response to RAI-9f); thus, propagation to the HPCS conduit would not occur.
- Direct impact of a cabinet fire on the HPCS conduits is not a concern since these conduits are not directly over or close enough to a cabinet to be considered a target.
- The impact of a cabinet fire on intervening combustibles involving cables, with propagation to the HPCS conduits, was considered. A fire was postulated in the top cubicle of 2BYS*SWG002B, which is relatively close to cable tray 2TX565N. Ignition temperature was exceeded at cable tray 2TX565N and the analysis indicated that the second tray above (2TX564N) could be involved. However, propagation above to critical trays and to the HPCS conduit would be unlikely.

Based on the above considerations, transient fires that could impact Division 2 AC or DC power and also Division 3 (HPCS) were ruled out as very unlikely. The following analysis conservatively estimates the frequency of a cabinet fire that could impact Division 2 AC or DC and affects the Division 3 (HPCS) conduits:

%F336XLnew = Cabinets * 1/20 * 0.05 = 9.45E-04/yr * 1/20 * 0.05 = 2.36E-06/yr

Where:

Cabinets = Total frequency of cabinet fires in fire zone 336XL (from FIVE methodology)
1/20 = One cabinet of 20 total cabinets that can potentially cause the event
0.05 = Probability that the fire is not manually suppressed before HPCS conduit is affected (Basis: Unreliability of 0.05 per demand is used for automatic detection and suppression because no significant reliability problems have been observed at NMP2 and the 0.05 value bounds the recommended values from FIVE without redundancy (Table 2 in FIVE Attachment 10.3).) The control room is directly above this room, within a short walking distance; therefore, a quick response is assumed.

The CCDP for this compartment is approximately 5.2E-04 (calculated using the CDF and fire frequency values from Table A2-1A of the June 1, 2010 NMPNS submittal). The CDF for this scenario is determined by multiplying the CCDP by the fire event frequency (%F336XLnew): CDF = 5.2E-04 * 2.36E-06 = ~1.2E-09, which is without considering the Division 1 DG out of service. Even with the Division 1 DG out of service, normal AC power is available to Division 1 switchgear.

In summary, fires can impact Division 2 AC or DC power and also the HPCS conduits; however, calculations show that the CDF is below 1E-8.

f. *For fire area FA19, it is stated that based on the cables being "so high" and IEEE 383 qualified, damage is unlikely, and that it "appears" transient fires would burn out before damage. It is not identified how high the cables are located, why IEEE 383 qualification makes it less likely to ignite a cable, nor how the judgment that a transient fire duration would be less than the time needed to cause cable damage was reached. The licensee needs to better justify its conclusions.*

Response RAI-12f

The term "so high" refers to the 9.8 foot height above floor level of cable tray 2TX565N, the first cable tray off the floor. Based on the table of pre-calculated critical heights for damage and ignition provided in the response to RAI-9f, cables at this height above the floor would not be expected to incur damage due to a transient fire at floor level, even without credit for detection and suppression.

NMP2 utilizes IEEE 383 qualified cable; therefore, a damage temperature of 700°F and an ignition temperature of 932°F were used in the evaluations. These values were selected based on guidance in the EPRI FIVE document and are considered conservative based on a review of the actual cable types specified and installed at NMP2. The TEFZEL insulated cables used at NMP2 have been proven by test to be difficult to ignite and are non-propagating, and smoke generation is insignificant.

g. *For fire areas FA34 and FA35 (Reactor Building), after providing a description of various features of the area with regards to fire protection features and the general layout of the area, conclusions are stated without a specific basis. For example, it is stated that if conduits and cable trays are located less than 5 feet from electrical equipment, unless both safety and nonsafety cables are present the cables are not considered important. Also, the area conclusion states that based on impacts, fire frequency, and the PRA, FA34 was screened out. The NRC staff cannot understand the basis for these types of statements for this area, and similar bases for FA35. The licensee needs to better justify its evaluation and conclusions for these areas.*

Response RAI-12g

As noted in Attachment A2-B of the June 1, 2010 NMPNS submittal, the initial screening for the reactor building included the total frequency of a fire for the entire fire area and assumed all the possible impacts that could occur did occur. Even with these very conservative assumptions, the initial CDF screening results were low for both FA34 and FA35, as shown in Table A2-1A of the June 1, 2010 NMPNS submittal.

Further evaluations were performed that concluded that the reactor building could be screened out. These evaluations were based on actual walkdowns of the building to identify dominant (highest frequency) fire sources and the proximity of those fire sources to potential important targets. Both radiant and plume fire impacts were considered. The potential for damage due to hot gas accumulation was also considered. Since cable trays are not routed on or near the ceilings, there is sufficient depth from the ceilings to the cable trays for a hot gas layer to propagate up to a higher level through openings between floors without impacting cables. Also, development of a hot gas layer at the top of the reactor building, above the refueling floor level, will not impact any PRA components.

Based on the results of the walkdowns and subsequent evaluations, no scenarios were identified for quantification where both safety and non-safety trains would be affected by a fire initiated at one of the high frequency sources (those sources with frequencies greater than 1E-03/year, as identified in Attachment A2-B of the June 1, 2010 NMPNS submittal). The location of safety cables and equipment versus non-safety equipment that could impact the feedwater system (affecting reactor vessel inventory control) and the main condenser (affecting normal heat removal) was specifically considered. This was of importance in the evaluation since at least one safety train was always available (in the other reactor building fire area) due to Appendix R separation. With the second safety train or the non-safety train available, the CCDP is low.

RAI-13

Section 3.2.1 of the Enclosure of the LAR states that the PRA model addresses internal and external events (including fires), and Section 3.2.4.1 identifies that the baseline CDF is 3.6E-6/year. There is no breakdown of the CDF to show the separate contribution of fires. However, in its supplemental submittal, the licensee provided additional details of the baseline fire PRA. Specifically, Table A2-2 appears to provide area-by-area CDF for both the IPEEE and the current 2010 results. The total CDF for the plant, determined by summing the individual fire area CDFs, is 1.35E-3/year, including a 1.25E-4/year contribution from non-control room fire scenarios and a 1.1E-3/year control room fire. It appears that this baseline CDF was then reviewed in more detail for this specific application, and qualitative dispositions of the various areas was then used to screen out the majority of the areas. The NRC staff is unable to determine from Table A2-2 and Attachment A2-B (the detailed evaluations) how a different baseline CDF was calculated. The licensee needs to identify the baseline fire risk contribution for both CDF and LERF, and discuss how the CDFs in Table A2-2 and the evaluations in Attachment A2-B relate to this total.

Response RAI-13

The screening values in Table A2-2 of the June 1, 2010 NMPNS submittal cannot be summed as these values are based on assuming all potential impacts in the compartment occur for the total ignition frequency without any consideration of spatial separation within the compartment (detailed evaluation). The following summarizes how to use Table A2-2 and Attachment A2-B:

- Table A2-2 contains a list of screening results for those compartments with a CDF > 1E-06 per the IPEEE results. Note that some compartments were retained even if they screened; e.g., both remote shutdown rooms (fire zones 338NZ and 343NZ) were modeled to retain symmetry in the modeling). These calculations were redone with the latest NMP2 model using a 1E-07 CDF screening value. Although some compartments screened with the latest NMP2 model, they were retained in the model if already modeled from the IPEEE. All of these screening calculations assume all impacts occur given a fire in the room and assume that all ignition sources have this same total impact.

- The last two columns of Table A2-2 summarize whether, based on the detailed evaluation in Attachment A2-B, the compartment was screened (determined to be below 1E-07) or modeled in the PRA. The last column identifies the fire initiating event. Table A2-3 provides the contribution of each fire initiating event in the model to the total baseline CDF.

The following summarizes the total CDF and total fire CDF for the baseline PRA:

Total Baseline CDF = 3.6E-6 (reported in Section 3.2.4 of the March 30, 2010 NMPNS submittal)

Total Baseline Fire CDF = 1.1E-6 (30%) (from Table A2-2 of the June 1, 2010 NMPNS submittal)

RAI-14

Three "gaps" are identified in the treatment of seismic risk for this application. The total seismic risk contribution to the baseline CDF and the application specific CDF are not provided. The NRC staff is unable to conclude that these are not significant because the justification provided is inadequate.

a. *Identify the total seismic CDF and LERF for both the baseline model and the application specific analysis.*

Response RAI-14a

The following summarizes the total CDF and LERF results for seismic events:

Case	CDF	Delta CDF	LERF	Delta LERF
Baseline	1.5E-7	NA	1.4E-7	NA
Div. 1 DG OOS	1.8E-7	3E-8	1.5E-7	1E-8
Div. 2 DG OOS	2.1E-7	6E-8	1.5E-7	1E-8

b. *It is stated that generic issues (assumed to be referring to uncertainties in the hazard analysis identified in the two referenced documents, EPRI NP-6395-D and NUREG-1488) and the impact on plan fragilities (assumed to be plant fragilities) do not impact this application, but there is no stated technical basis for this conclusion. The licensee should provide a more robust disposition of this issue.*

Response RAI-14b

The "gap" identified in Attachment 3 of the June 1, 2010 NMPNS submittal was referring to the generic industry activities associated with Generic Issue 199, "Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern Unit States on Existing Plants." Information Notice 2010-19 was recently issued on this subject. The seismic hazard has not been updated in the NMP2 seismic PRA and the identification of this gap is to simply acknowledge the need to track this issue for future updates. As previously noted in Attachment 3, this issue does not impact the risk evaluation performed for the proposed extension of the DG CT.

c. *It is stated that some component margins above the 0.5g high confidence of low probability of failure "may not be significant," and then states that additional fragility analysis would be required. The NRC staff is unclear as to what this statement intends for this specific application -are additional analyses being conducted to support this application? Are these components with low margins significant to this application? What would be the consequence of failure of these low margin components to this application? The licensee should further discuss its basis for disposition of this issue.*

Response RAI-14c

Additional analyses are not being performed to support the proposed amendment. As stated in Attachment 3 of the June 1, 2010 NMPNS submittal, a 0.5g high confidence of low probability of failure (HCLPF) value was used as a screening value during the IPEEE, and a plant fragility (COMP1) representing this screening value is included in the PRA model. This was recognized as a potential limitation and conservatism since it dominates seismic risk. The reference to "low margins" was meant to refer to components that screened above or at the 0.5g HCLPF value. There is no consequence of failing the components with the "low margin" to the HCLPF screening value since this is already accounted for in the COMP1 fragility.

d. *It is stated that more detailed human reliability analyses should be completed for future updates, but that it is "unlikely" to impact the application based on the insensitivity of ex-control room fire actions. The NRC staff does not understand the rationale that seismic recovery actions are similar in significance to ex-control from post-fire recovery actions. The licensee should further discuss its basis for disposition of this issue.*

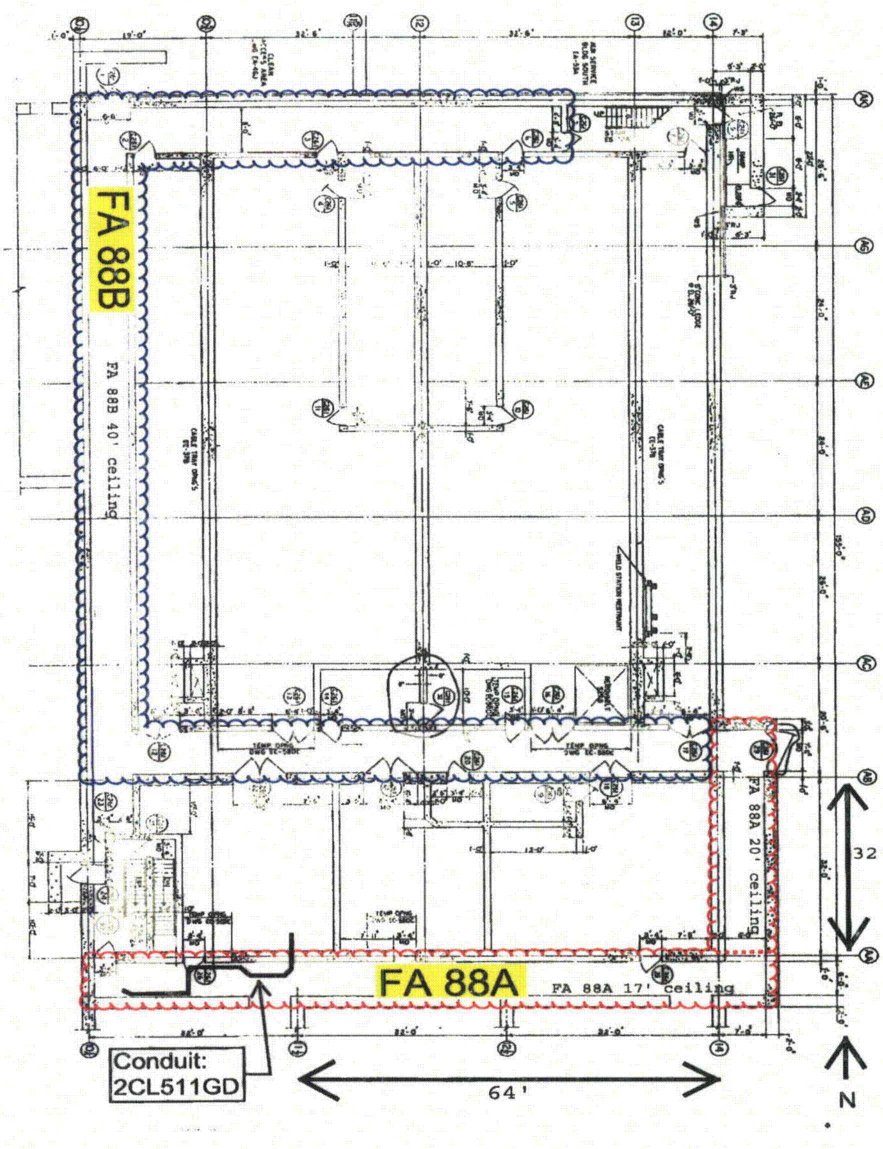
Response RAI-14d

The insights gained from the fire sensitivity analysis of operator actions related to events outside the control room are expected to be similar for seismic events. The similarities include the following:

- When there is ample time following the initiating event, whether fire or seismic, it is expected that the hazard impact on the human error probability (HEP) would be significantly less.

- The potential impact of hazards on the important HEPs will affect the baseline risk, but the change in risk associated with the specific DG out-of-service (OOS) configuration is usually small, as shown for fires. This is because the DG OOS configuration has an impact on risk due to the importance of the DG itself, but does not have an impact on the baseline HEP. Thus, any increase in HEP will impact the baseline more than the change in risk because the HEP impacts both the baseline and the CDF for the DG OOS configuration. When subtracted the delta is relatively small.

Figure 12c-1
Drawing Showing Fire Area FA88 on Elevation 261' of the Control Building



ATTACHMENT 2

LIST OF REGULATORY COMMITMENTS

The following table is an update to the list of regulatory commitments that was originally provided in Attachment 1 of the NMPNS dated March 30, 2010. Any other statements in the March 30, 2010 NMPNS submittal or in this submittal represent intended or planned actions. They are provided for information purposes and are not considered to be regulatory commitments.

REGULATORY COMMITMENT	SCHEDULED COMPLETION DATE
1. Complete the modification and associated implementing procedures to provide the Division 3 diesel generator (DG) with a source of backup cooling water from the fire protection water supply system and its associated diesel-driven fire water pumps.	90 days following NRC approval of the license amendment request.
2. Prepare or revise appropriate procedures to include provisions for implementing compensatory measures and configuration risk management controls when entering an extended DG completion time (CT) (greater than 72 hours and up to 14 days), including the following: a. The other two DGs are operable and no planned maintenance or testing activities are scheduled on those two DGs. b. No planned maintenance or testing activities are scheduled in Scriba Substation, the NMP2 115 kV switchyard, or on the 115 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability. c. The high pressure core spray (HPCS) system is available and no planned maintenance or testing activities are scheduled. d. The reactor core isolation cooling (RCIC) system is available and no planned maintenance or testing activities are scheduled. e. The NMP2 and NMP1 diesel-driven fire pumps and the cross-tie between the NMP2 and NMP1 fire protection water supply systems are available to provide a backup cooling water supply to the Division 3 DG and no planned maintenance or testing activities are scheduled. f. The Division 1 and Division 2 residual heat removal (RHR) pumps and the low pressure core spray (LPCS) pump are available and no planned maintenance or testing activities are scheduled. g. Both divisions of the redundant reactivity control system and the standby liquid control system (equipment required for mitigation of anticipated transients without scram (ATWS) events) are available and no planned maintenance or testing activities are scheduled. h. The stability of existing and projected grid conditions will be confirmed prior to planned entry into the extended DG CT by contacting the transmission system operator (TSO).	90 days following NRC approval of the license amendment request.

REGULATORY COMMITMENT	SCHEDULED COMPLETION DATE
i. Operating crews will be briefed on the DG work plan. As a minimum, the briefing will include the following important procedural actions that could be required in the event a loss of offsite power (LOOP), station blackout (SBO), or fire condition occurs: – Alignment of the fire protection water supply system to provide cooling water to the Division 3 DG. – Establishing the cross-connection to allow the Division 3 DG to power either Division 1 or Division 2 loads. – Utilizing the portable generator as a backup source of AC power to one of the Division 1 or Division 2 battery chargers. – Utilizing the portable power supplies to maintain operability of the safety relief valves (SRVs). – Closing containment isolation valves in the drywell floor drain and equipment drain lines.	
j. The extended DG CT will not be entered for planned maintenance if severe weather conditions (high winds, tornado, or heavy snow/ice) with the potential to degrade or limit offsite power availability are present, or if official weather forecasts are predicting such conditions to occur.	
k. Except for the room housing the inoperable DG, no hot work permits will be active for the control building or the normal switchgear rooms.	
l. A portable generator is available as a temporary backup source of AC power to one of the Division 1 or Division 2 battery chargers and is pre-staged within the protected area near the NMP2 control building.	
m. Four portable power supplies are available for use to facilitate operation of safety relief valves to maintain RPV pressure control for an extended SBO condition and are verified to be functional.	

ATTACHMENT 3

CHANGES TO TECHNICAL SPECIFICATION BASES (MARK-UP)

REVISED

The mark-up for NMP2 Technical Specification Bases page B 3.8.1-10, originally provided in Attachment 3 of the March 30, 2010 NMPNS submittal, is revised. Specifically, the list of compensatory measures and configuration risk management controls in "INSERT B" is modified. This Bases page is provided for information only.

BASES

ACTIONS

B.2 (continued)

required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG(s), SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DGs, the other DGs are declared inoperable upon discovery, and Condition E or G of LCO 3.8.1 is entered, as applicable. Once the failure is repaired, and the common cause failure no longer exists, Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of those DG(s).

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the Deficiency Event Report Program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 9), 24 hours is reasonable time to confirm that the OPERABLE DG(s) are not affected by the same problem as the inoperable DG.

B.4

~~According to Regulatory Guide 1.93 (Ref. 8), operation may continue in Condition B for a period that should not exceed 72 hours.~~ In ~~this condition~~ Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E distribution system. Insert A The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period. Insert B

(continued)

INSERT A (for TS Bases page B 3.8.1-10) [Unchanged]

Although Condition B applies to a single inoperable DG, several Completion Times are specified for this Condition.

The first Completion Time applies to an inoperable Division 3 DG.

INSERT B (for TS Bases page B 3.8.1-10) [Revised]

This Completion Time begins only "upon discovery of an inoperable Division 3 DG" and, as such, provides an exception to the normal "time zero" for beginning the allowed outage time "clock" (i.e., for beginning the clock for an inoperable Division 3 DG when Condition B may have already been entered for another equipment inoperability and is still in effect).

The second Completion Time (14 days) applies to an inoperable Division 1 or Division 2 DG and is a risk-informed Completion Time based on a plant-specific risk analysis. The extended Completion Time would typically be used for voluntary planned maintenance or inspections but can also be used for corrective maintenance. However, use of the extended Completion Time for voluntary planned maintenance should be limited to once within an operating cycle (24 months) for each DG (Division 1 and Division 2). When utilizing an extended DG Completion Time (greater than 72 hours and up to 14 days), the compensatory measures and configuration risk management controls listed below shall be implemented. For planned maintenance utilizing an extended Completion Time, these measures and controls shall be implemented prior to entering Condition B. For an unplanned entry into an extended Completion Time, these measures and controls shall be implemented without delay.

1. The other two DGs are operable and no planned maintenance or testing activities are scheduled on those two DGs.

2. No planned maintenance or testing activities are scheduled in Scriba Substation, the NMP2 115 kV switchyard, or on the 115 kV power supply lines and transformers which could cause a line outage or challenge offsite power availability.

3. The HPCS system is available and no planned maintenance or testing activities are scheduled.

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

5. The NMP2 and NMP1 diesel-driven fire pumps and the cross-tie between the NMP2 and NMP1 fire protection water supply systems are available to provide a backup cooling water supply to the Division 3 DG and no planned maintenance or testing activities are scheduled.

INSERT B (continued)

6. The Division 1 and Division 2 residual heat removal (RHR) pumps and the low pressure core spray (LPCS) pump are available and no planned maintenance or testing activities are scheduled.

7. Both divisions of the redundant reactivity control system and the standby liquid control system (equipment required for mitigation of anticipated transients without scram (ATWS) events) are available and no planned maintenance or testing activities are scheduled.

8. The stability of existing and projected grid conditions will be confirmed prior to planned entry into the extended DG CT by contacting the transmission system operator (TSO).

9. Operating crews will be briefed on the DG work plan. As a minimum, the briefing will include the important procedural actions that could be required in the event a LOOP, SBO, or fire condition occurs.

10. The extended DG CT will not be entered for planned maintenance if severe weather conditions (high winds, tornado, or heavy snow/ice) with the potential to degrade or limit offsite power availability are present, or if official weather forecasts are predicting such conditions to occur.

11. Except for the room housing the inoperable DG, no hot work permits will be active for the control building or the normal switchgear rooms.

12. A portable generator is available as a temporary backup source of AC power to one of the Division 1 or Division 2 battery chargers and is pre-staged within the protected area near the NMP2 control building.

13. Four portable power supplies are available for use to facilitate operation of safety relief valves to maintain RPV pressure control for an extended SBO condition and are verified to be functional.