UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

December 15, 2010

Mr. Samuel L. Belcher
Vice President Nine Mile Point
Nine Mile Point Nuclear Station, LLC
P.O. Box 63
Lycoming, NY 13093

SUBJECT: 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)

Dear Mr. Belcher:

By letter dated March 30, 2010, as supplemented on June 1, 2010, Nine Mile Point Nuclear Station, LLC (NMPNS) submitted a license amendment for Nine Mile Point, Unit No. 2 (NMP2). The proposed amendment would modify NMP2 Technical Specification (TS) Section 3.8.1, "AC Sources - Operating," to extend the Completion Time for an inoperable Division 1 or Division 2 diesel generator from 72 hours to 14 days. The proposed amendment represents a risk-informed licensing change.

The NRC staff is reviewing the information provided in those letters and has determined that additional information is needed to support its review. Enclosed is the NRC staff's request for additional information (RAI). The RAI was discussed with your staff on December 8, 2010, and it was agreed that your response would be provided by January 14, 2010.

Sincerely,

Richard V. Guzman, Senior Project Manager
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-410

Enclosure:
As stated

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REQUEST FOR ADDITIONAL INFORMATION (RAI) FOR

LICENSE AMENDMENT REQUEST RE: EXTENSION OF COMPLETION TIME FOR

INOPERABLE DIESEL GENERATOR

PROBABILITIC RISK ASSESSMENT REVIEW

NINE MILE POINT NUCLEAR STATION, LLC

NINE MILE POINT NUCLEAR STATION, UNIT NO. 2

DOCKET NO. 50-410

By letter dated March 30, 2010 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML100900460), as supplemented by letter dated June 1, 2010 (ML101600452), Nine Mile Point Nuclear Station, LLC (NMPNS or the licensee) submitted a license amendment request (LAR) for Nine Mile Point, Unit No. 2 (NMP2) requesting changes to the Technical Specifications (TSs) to extend the allowable completion time from 72 hours to 14 days when one emergency diesel generator (DG) is inoperable. The NRC staff is reviewing the LAR and has determined that additional information as requested below will be needed to support its review.

Based on the NRC staffs review of the LAR and the supplemental information, the NRC staff has identified areas for which additional information is needed to complete its review.

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.

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.

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.

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.

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.

    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.

    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.

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.

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.

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.

    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.

    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.

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.

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.

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.

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 of 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.

   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.

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.

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.

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.

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.

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.

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?

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 1E-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.

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.

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.

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.

    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.

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.

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.

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?

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.

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.

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.

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.

    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.

    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.

    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.

December 15, 2010

Mr. Samuel L. Belcher
Vice President Nine Mile Point
Nine Mile Point Nuclear Station, LLC
P.O. Box 63
Lycoming, NY 13093

SUBJECT: 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)

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Sincerely,

/RA/

Richard V. Guzman, Senior Project Manager
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
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Docket No. 50-410

Enclosure:
As stated

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ADAMS Accession No.: ML103130327 *RAI provided by memo. **Via email. No substantial changes made.

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DATE	12/14/10	12/14/10**	9/2/10*	12/15/10

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