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

March 18, 2010

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

SUBJECT: NINE MILE POINT NUCLEAR STATION, UNIT NO. 2 - ISSUANCE OF AMENDMENT REGARDING REMOVAL OF OPERATING MODE RESTRICTIONS FOR PERFORMING HIGH PRESSURE CORE SPRAY EMERGENCY DIESEL GENERATOR SURVEILLANCE TESTING (TAC NO. ME1042)

Dear Mr. Belcher:

The Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment No. 133 to Renewed Facility Operating License No. NPF-69 for the Nine Mile Point Nuclear Station (NMPNS), Unit No. 2 (NMP2), in response to your application dated March 30, 2009 (Agencywide Documents Access Management System (ADAMS) Accession No. ML090970277), as supplemented on November 2, 2009 (ADAMS Accession No. ML093140658).

This amendment modifies the NMP2 Technical Specification (TS) 3.8.1, " AC Sources – Operating," to remove operating mode restrictions for the performance of certain Surveillance Requirements (SRs) pertaining to the Division 3, High Pressure Core Spray (HPCS) Emergency Diesel Generator (DG). The testing in Modes 1 or 2 were previously prohibited in SR 3.8.1.7, SR 3.8.1.8, and SR 3.8.1.10, and in Modes 1, 2, or 3 in SR 3.8.1.9, SR 3.8.1.11, SR 3.8.1.14, SR 3.8.1.15, and SR 3.8.1.17. The amendment removes these Mode restrictions and allows the above SRs to be performed in any operating mode for the Division 3 DG. The Mode restrictions remain applicable to the other two safety-related (Division 1 and Division 2) DGs.

A copy of the related Safety Evaluation is enclosed. A Notice of Issuance will be included in the Commission's next regular biweekly *Federal Register* notice.

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

Enclosures:
1. Amendment No. 133 to NPF-69
2. Safety Evaluation

cc w/encls: Distribution via Listserv

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

NINE MILE POINT NUCLEAR STATION, LLC (NMPNS)

DOCKET NO. 50-410

NINE MILE POINT NUCLEAR STATION, UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 133
Renewed License No. NPF-69

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Nine Mile Point Nuclear Station, LLC (the licensee) dated March 30, 2009, as supplemented on November 2, 2009, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. NPF-69 is hereby amended to read as follows:

   (2) Technical Specifications

   The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, as revised through Amendment No. 133 are hereby incorporated into this license. Nine Mile Point Nuclear Station, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of the date of its issuance and shall be implemented within 90 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

Nancy L. Salgado

Nancy L. Salgado, Chief
Plant Licensing Branch I-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the License and Technical Specifications

Date of Issuance: March 18, 2010

ATTACHMENT TO LICENSE AMENDMENT NO. 133

TO RENEWED FACILITY OPERATING LICENSE NO. NPF-69

DOCKET NO. 50-410

Replace the following page of the Renewed Facility Operating License with the attached revised page. The revised page is identified by amendment number and contains marginal lines indicating the areas of change.

Remove Page	Insert Page
4	4

Replace the following pages of Appendix A, Technical Specifications, with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove Pages	Insert Pages
3.8.1-8	3.8.1-8
3.8.1-9	3.8.1-9
3.8.1-10	3.8.1-10
3.8.1-11	3.8.1-11
3.8.1-12	3.8.1-12
3.8.1-15	3.8.1-15
3.8.1-17	3.8.1-17

(1) Maximum Power Level

Nine Mile Point Nuclear Station, LLC is authorized to operate the facility at reactor core power levels not in excess of 3467 megawatts thermal (100 percent rated power) in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, as revised through Amendment No. 133 are hereby incorporated into this license. Nine Mile Point Nuclear Station, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Fuel Storage and Handling (Section 9.1, SSER 4)*

a. Fuel assemblies, when stored in their shipping containers, shall be stacked no more than three containers high.

b. When not in the reactor vessel, no more than three fuel assemblies shall be allowed outside of their shipping containers or storage racks in the New Fuel Vault or Spent Fuel Storage Facility.

c. The above three fuel assemblies shall maintain a minimum edge-to-edge spacing of twelve (12) inches from the shipping container array and approved storage rack locations.

d. The New Fuel Storage Vault shall have no more than ten fresh fuel assemblies uncovered at any one time.

(4) Turbine System Maintenance Program (Section 3.5.1.3.10, SER)

The operating licensee shall submit for NRC approval by October 31, 1989, a turbine system maintenance program based on the manufacturer's calculations of missile generation probabilities. (Submitted by NMPC letter dated October 30, 1989 from C.D. Terry and approved by NRC letter dated March 15, 1990 from Robert Martin to Mr. Lawrence Burkhardt, III).

* The parenthetical notation following the title of many license conditions denotes the section of the Safety Evaluation Report (SER) and/or its supplements wherein the license condition is discussed.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.7	----------NOTES---------- 1. This Surveillance shall not be performed in MODE 1 or 2 (not applicable to Division 3 DG). However, credit may be taken for unplanned events that satisfy this SR. 2. If performed with DG synchronized with offsite power, it shall be performed within the power factor limit. However if grid conditions do not permit, the power factor limit is not required to be met. Under this condition the power factor shall be maintained as close to the limit as practicable. ---------- Verify each required DG rejects a load greater than or equal to its associated single largest post-accident load, and following load rejection, the frequency is ≤ 64.5 Hz for Division 1 and 2 DGs and ≤ 66.75 Hz for Division 3 DG.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.8	---------- NOTES ---------- 1. This Surveillance shall not be performed in MODE 1 or 2 (not applicable to Division 3 DG). However, credit may be taken for unplanned events that satisfy this SR. 2. If grid conditions do not permit, the power factor limit is not required to be met. Under this condition the power factor shall be maintained as close to the limit as practicable. ---------- Verify each required DG operating within the power factor limit does not trip and voltage is maintained: a. ≤ 4576 V during and following a load rejection of a load ≥ 4400 kW for Division 1 and 2 DGs; and b. ≤ 5824 V during and following a load rejection of a load ≥ 2600 kW for Division 3 DG.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	---------- NOTES ---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3 (not applicable to Division 3 DG). However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify on an actual or simulated loss of offsite power signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2 only; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 13.20 seconds, 2. energizes auto-connected shutdown loads for Division 1 and 2 DGs only, through the associated automatic load sequence time delay relays, 3. maintains steady state voltage ≥ 3950 V and ≤ 4370 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected shutdown loads for ≥ 5 minutes for Division 1 and 2 DGs and supplies permanently connected shutdown loads for ≥ 5 minutes for Division 3 DG.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.10	---------- NOTES ---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1 or 2 (not applicable to Division 3 DG). However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify on an actual or simulated Emergency Core Cooling System (ECCS) initiation signal each required DG auto-starts from standby condition and: a. In ≤ 10 seconds after auto-start, achieves voltage ≥ 3950 V for Division 1 and 2 DGs and ≥ 3820 V for Division 3 DG, and frequency ≥ 58.8 Hz for Division 1 and 2 DGs and ≥ 58.0 Hz for Division 3 DG; b. Achieves steady state voltage ≥ 3950 V and ≤ 4370 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz; c. Operates for ≥ 5 minutes; d. Permanently connected loads remain energized from the offsite power system for Divisions 1 and 2 only; and e. Emergency loads are auto-connected through the associated automatic load sequence time delay relays to the offsite power system for Divisions 1 and 2 only.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.11	---------- NOTE ---------- This Surveillance shall not be performed in MODE 1, 2, or 3 (not applicable to Division 3 DG). However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify each required DG's automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ECCS initiation signal except: a. Engine overspeed; and b. Generator differential current.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.14	---------- NOTE ---------- This Surveillance shall not be performed in MODE 1, 2, or 3 (not applicable to Division 3 DG). However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify each required DG: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	24 months
SR 3.8.1.15	---------- NOTE ---------- This Surveillance shall not be performed in MODE 1, 2, or 3 (not applicable to Division 3 DG). However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify, with a DG operating in test mode and connected to its bus, an actual or simulated ECCS initiation signal overrides the test mode by: a. Returning DG to ready-to-load operation; and b. Automatically energizing the emergency load from offsite power.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.17	---------- NOTES ---------- 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, or 3 (not applicable to Division 3 DG). However, credit may be taken for unplanned events that satisfy this SR. ---------- Verify, on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ECCS initiation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses for Divisions 1 and 2 only; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. for Divisions 1 and 2, energizes auto-connected emergency loads through the associated automatic load sequence time delay relays and for Division 3, energizes auto-connected emergency loads, 3. maintains steady state voltage ≥ 3950 V and ≤ 4370 V, 4. maintains steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	24 months

(continued)

UNITED STATES
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WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 133

TO RENEWED FACILITY OPERATING LICENSE NO. NPF-69

NINE MILE POINT NUCLEAR STATION, LLC

NINE MILE POINT NUCLEAR STATION, UNIT NO. 2

DOCKET NO. 50-410

1.0 INTRODUCTION

By letter dated March 30, 2009 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML090970277), as supplemented by letter dated November 2, 2009 (ADAMS Accession No. ML093140658), Nine Mile Nuclear Station, LLC (NMPNS or the licensee) submitted a license amendment request (LAR) for changes to the Nine Mile Point, Unit No. 2 (NMP2) Technical Specifications (TSs). The supplement dated November 2, 2009, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the Nuclear Regulatory Commission (NRC) staff's original proposed no significant hazards consideration determination noticed in the *Federal Register* on June 16, 2009 (74 FR 28577).

The proposed amendment would modify the NMP2 Technical Specification (TS) 3.8.1, "AC Sources – Operating," to remove mode restrictions for the performance of certain Surveillance Requirements (SRs) pertaining to the Division 3, High Pressure Core Spray (HPCS) Emergency Diesel Generator (DG). The TSs currently prohibit performing the testing required by SR 3.8.1.7, SR 3.8.1.8, and SR 3.8.1.10 in Modes 1 or 2, and prohibit performing the testing required by SR 3.8.1.9, SR 3.8.1.11, SR 3.8.1.14, SR 3.8.1.15, and SR 3.8.1.17 in Modes 1, 2, or 3. The proposed amendment would remove these Mode restrictions and allows the above SRs to be performed in any operating mode for the Division 3 DG. The Mode restrictions would remain applicable to the other two safety-related (Division 1 and Division 2) DGs.

The licensee stated that the reason for the proposed amendment is to provide greater flexibility in scheduling Division 3 DG testing activities by allowing the testing to be performed during non-outage times. Having a completely tested Division 3 DG available for the duration of a refueling outage would reduce the number of system re-alignments and operator workload during an outage, and can provide significant reductions in outage critical path time.

2.0 REGULATORY EVALUATION

In Section 50.36 of Title 10 of the *Code of Federal Regulations* (10 CFR), the NRC established its regulatory requirements related to the content of TSs. Pursuant to 10 CFR 50.36, TSs are

required to include items in the following five specific categories: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation (LCOs); (3) SRs; (4) design features; and (5) administrative controls. The regulation does not specify the particular requirements to be included in a plant's TSs. In general, there are two classes of changes to TSs: (1) changes needed to reflect modifications to the design basis, as TSs are derived from the design basis, and (2) changes to take advantage of the evolution in policy and guidance as to the required content and preferred format of TSs over time. In determining the acceptability of such changes, the NRC staff interprets the requirements in 10 CFR 50.36 using as a model the accumulation of generically approved guidance in the Improved Standard Technical Specifications (ISTS). For this review, the NRC staff used NUREG-1433, Revision 3, "Standard Technical Specifications, General Electric Plants BWR/4."

10 CFR, Appendix A of Part 50, General Design Criterion (GDC) 17, "Electric power systems," requires, in part, that "An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety ... The onsite electric power supplies, including the batteries, and the onsite electric distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure . . ."

GDC 18, "Inspection and testing of electric power systems," requires, in part, that "Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features . . ."

3.0 TECHNICAL EVALUATION

3.1 Description of NMP2 Class 1E AC Distribution System

The NMP2 Class 1E AC distribution system supplies electrical power to three divisional load groups, Divisions 1, 2, and 3, with each division powered by an independent Class 1E 4.16 kiloVolt (kV) emergency bus. The Division 1 and 2 emergency buses each have a separate and independent offsite source of power. The Division 3 (HPCS) emergency bus can be supplied from either of the two independent offsite sources.

The onsite standby power source for each 4.16 kV emergency bus is a dedicated DG. A DG starts automatically on a loss-of-coolant accident (LOCA) signal or on Class 1E 4.16 kV emergency bus degraded voltage or undervoltage signal. After the DG has started, it automatically ties to its respective 4.16 kV emergency bus after offsite power is tripped as a consequence of emergency bus undervoltage or degraded voltage, independent of or coincident with a LOCA signal. The DGs also start and operate in the standby mode without tying to their emergency buses on a LOCA signal alone. In the event of a loss of offsite power (LOOP), the engineered safety featured (ESF) electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a design-basis accident (DBA) such as a LOCA. The Division 3 (HPCS) DG provides all required power for the startup and operation of the HPCS system.

3.2 Evaluation of Proposed Changes

Provisions are made for manual paralleling with offsite power sources to load the DG during the test mode. If a LOOP occurs, a parallel-loaded DG would attempt to supply power to the offsite

test loads through the closed feed breakers. A set of three directional overcurrent relays trip the offsite power feed breakers if the overcurrent exceeds a preset value. However, the DG continues to power the Division 3 emergency bus. In case a LOCA signal occurs while the Division 3 DG is running in parallel with the offsite power source, the DG feed breaker automatically trips; the HPCS pump motor and associated HPCS loads automatically start, with the Division 3 emergency bus being powered from the offsite power source. The LOCA signal overrides the test start signal during auto mode and the DG continues to run unloaded.

The HPCS system is designed to allow all active components to be tested during normal plant operations. The system has a full-flow test line to either the suppression pool or the condensate storage tank (CST) and a minimum flow bypass line to the suppression pool. These features allow system testing without discharging into the reactor vessel.

In response to the NRC staff's request, the licensee, in its letter dated November 2, 2009, provided the following explanation regarding the parallel mode operation of Division 3 DG in the event grid voltage degrades to a value resulting in HPCS DG bus voltage marginally above the degraded voltage relay set point:

> When the Division 3 DG is operating in parallel mode of operation on its associated 4.16 kV emergency bus, the generator is typically operating near rated load per surveillance procedure requirements, with the voltage regulator operating in automatic control mode. Nominal emergency bus voltage is 4160 V and rated generator output current for the Division 3 DG is approximately 494 amps. The degraded voltage relay minimum dropout is 3820 V. If the voltage supplied from the offsite source were to decrease to approximately 3800 V at the emergency bus level (approximately 9 percent low) with the Division 3 DG in parallel mode of operation tied to the emergency bus, the immediate effect would be that the DG voltage regulator would attempt to maintain bus voltage at approximately 4160 V. However, this would not be possible as the grid is essentially an infinite source. As emergency bus voltage lowered, and with no operator action, the generator would increase reactive power output, and amperage supplied from the DG would increase. This is due to the constant power output of the engine with unchanged governor settings along with the decrease in bus voltage and the automatic action of the DG voltage regulator operating in parallel mode. With a decrease in voltage, the automatic voltage regulator would provide additional current due to an effective increase in generator excitation in an attempt to restore bus voltage. A review of the DG protection scheme and coordination confirms that the increased DG output current would result in a trip of the offsite feeder breaker to the Division 3 emergency bus due to directional overcurrent relay actuation prior to other generator protective relay actuation, allowing the DG to remain connected to its bus and isolated from offsite power. Once the offsite power supply breaker opens, the DG output current would decrease to a minimal value and bus voltage would recover to the nominal value (4160 V).

The NRC staff finds the above explanation as acceptable since the NMP2 electrical distribution design would allow Division 3 DG to remain connected to its bus and isolated from offsite power, in the event the grid voltage degrades to a value which results in the HPCS DG bus voltage marginally above the degraded voltage relay set point.

In response to another NRC staff question, the licensee, in its letter dated November 2, 2009, provided the following explanation regarding the evaluation of off-nominal DG frequency (due to droop mode) and the off-nominal DG voltage on the safety-related loads fed by the DG, if a LOCA occurs and given that the DG does not automatically go from the droop mode in parallel operation to the isochronous mode if tripped from parallel mode:

> The Division 3 DG is considered operable during parallel operation. For the surveillance tests in question, the DG is operated in parallel mode with load near the rated value. If a loss of offsite power (LOOP) should occur while in this condition, the increase in current output from the DG will result in operation of the directional overcurrent relays, which will open the offsite power supply breakers and isolate the Division 3 emergency bus from offsite power. The Division 3 DG would remain connected to its associated 4.16 kV bus. In this condition, DG frequency would increase by approximately 3 percent to approximately 61.7 Hz (based on full load reject test results) due to the droop characteristic of the engine governor. Also, immediately following the LOOP, and after the offsite power supply breakers tripped open, the DG voltage regulator would automatically shift from parallel to isochronous mode of operation, with voltage automatically controlled to approximately 4160 V nominal output to the Division 3 bus. These DG voltage regulator actions result from control logic provided by emergency bus supply breaker auxiliary contacts.
>
> In the event of a subsequent loss of coolant accident (LOCA) signal, the HPCS loads would be started at a slightly elevated frequency (approximately 61.7 Hz) and at approximately nominal voltage (4160 V). As the HPCS loads start, with the voltage regulator in automatic/isochronous mode and the engine governor in the parallel regulation (droop) mode, voltage and frequency would stabilize to steady state values that are at or near normal bus voltage and frequency without any operator action. The initially elevated frequency during HPCS load starting would not have an adverse impact on the ability of the HPCS pump motor to start or on the operation of associated equipment since these components are designed for a wider frequency range than that which would be experienced. System flow requirements would also not be impacted, as frequency would return to approximately 60 Hz as the HPCS pump motor load increased to its final steady-state value (near full Division 3 DG rated load). Thus, in the very unlikely event that a LOOP and LOCA occurred during testing with the Division 3 DG operating in parallel with offsite power, the Division 3 DG would be fully capable of performing its specified safety function.

The NRC staff finds the above explanation as acceptable since Division 3 DG would remain capable of performing its specified safety function, in the event that a LOOP and LOCA occurred during testing with the Division 3 DG operating in parallel with offsite power.

In response to NRC staff's request, the licensee, in its letter dated November 2, 2009, also provided explanation of the statement: "Voltage transients on these [Division 3] buses during online testing will likely be less than those experienced when testing during shutdown conditions." The licensee explained that the statement was meant to convey that voltage perturbations on the 4.16 kV buses would likely be smaller in magnitude during DG testing with

the plant online as compared to DG testing during shutdown conditions. The loading on the reserve station service transformers (RSSTs) is typically lower with the unit online than during shutdown conditions. With a lower loading on the RSSTs during online conditions, there would be a slightly smaller magnitude of perturbation to the associated 4.16kV buses compared with shutdown conditions, since the RSSTs would represent a slightly stronger source to any transient. The NRC staff finds this explanation reasonable and thus acceptable.

SR 3.8.1.7 and SR 3.8.1.8

SR 3.8.1.7 requires verification that following rejection of a load greater than or equal to the associated single largest post-accident load for the Division 3 DG (i.e., the 2435 kW HPCS pump), the frequency remains within specified limits. SR 3.8.1.8 requires verification that following a full load rejection (a load > 2600 kW), the Division 3 DG does not trip and voltage is maintained within specified limits. Currently, these SRs contain a Note that prohibits performance in Modes 1 or 2. The TS Bases state the reason for the Note is that performing the surveillances could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.

The licensee provided the following discussion in the LAR to justify why the mode restrictions of SR 3.8.1.7 and SR 3.8.1.8 for Division 3 DG are not necessary:

- During plant operation, the 4.16 kV emergency buses are normally aligned to the two RSSTs, each of which is fed from a 115 kV offsite line. This is the same configuration maintained during plant shutdown when the load rejection testing is currently conducted. The probability for a grid disturbance to occur during the timeframe of a test performed per SR 3.8.1.7 or SR 3.8.1.8 is low. Protective relaying for the DG would protect the DG while it is connected to the offsite power source.

- For performance of the load rejection tests, the typical approach taken is to load the Division 3 DG to the required load (via offsite power) and then open the DG output breaker. Opening the DG output breaker separates the DG from its associated emergency bus and allows the offsite power source to continue to supply the bus. This evolution has little impact on the plant electrical distribution system. The power system loading during such testing remains within the rating of all transformers, switchgear, and breakers, both before and after the load rejection, and performance of the load rejection SRs does not cause any significant perturbations to the electrical distribution systems as the DG is separated from the bus.

- Paralleling the Division 3 DG with offsite power is similar to the existing monthly run of the DG (SR 3.8.1.3) that is conducted with the plant on line, which has no mode restriction.

- Starting the HPCS pump motor is actually a more limiting transient than a Division 3 full load rejection due to the presence of the pump motor starting transient. HPCS pump starts are routinely performed online, with offsite power supplying the Division 3 emergency bus, to satisfy quarterly in-service testing requirements. These tests have not disturbed plant operation.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated November 2, 2009, and agrees that removal of mode restrictions (i.e., allowing the SR to be conducted in Mode 1 or 2) for Division 3 DG in SR 3.8.1.7 and SR 3.8.1.8 will have minimal impact on the safe operation of the plant.

SR 3.8.1.9

SR 3.8.1.9 requires verification that the Division 3 DG automatically starts from the standby condition on an actual or simulated LOOP signal, achieves the required voltage and frequency, and supplies permanently connected loads for > 5 minutes. The NMP2 design for the Division 3 DG does not feature the automatic sequencing of loads. Currently, this SR contains a Note that prohibits performance in Modes 1, 2, or 3. The TS Bases state the reason for the Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems.

The licensee provided the following discussion in the LAR to justify why the mode restrictions for SR 3.8.1.9 for Division 3 DG are not necessary:

- With the Division 3 4.16 kV emergency bus aligned to an RSST, a LOOP is simulated by the use of key-operated switches that cause the Division 3 emergency switchgear to de-energize, thereby isolating the Division 3 electrical subsystem from the other two safety-related electrical subsystems. The Division 3 DG starts, re-energizes its associated emergency bus, and runs for at least 5 minutes. Since, this test does not involve an emergency core cooling system (ECCS) initiation signal, the HPCS pump does not automatically start; however, following the 5-minute run, the HPCS pump is manually started for the purpose of performing testing per SR 3.8.1.14.

- Because the HPCS system is a stand-alone system with a dedicated DG and independent electrical distribution system, there is minimal opportunity for the performance of this SR to have any impact on other safety-related plant equipment or normal plant operation. The simulated LOOP signal is generated only at the Division 3 switchgear and does not affect the other two safety-related electrical divisions. Additionally, due to the relative size of the loads associated with the HPCS system (2540 kW), there is minimal potential for this testing to create an offsite power supply perturbation when the Division 3 4.16 kV emergency bus is de-energized.

- Although the offsite source of power to the Division 3 emergency bus is disconnected for this test, the period of time that this condition exists is small and is considered acceptable since the HPCS system is already inoperable for performance of the test according to the Note to the applicability requirements for TS 3.8.1.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated November 2, 2009, and agrees that removal of mode restrictions (i.e., allowing the SR to be conducted in Mode 1, 2, or 3) for Division 3 DG in SR 3.8.1.9 will have minimal impact on the safe operation of plant.

SR 3.8.1.10

SR 3.8.1.10 requires verification that the Division 3 DG automatically starts from the standby condition on an actual or simulated ECCS initiation signal, achieves the required voltage and frequency within the specified time, and operates for ≥ 5 minutes. Currently, this SR contains a Note that prohibits performance in Modes 1 or 2. The TS Bases state the reason for the Note is that performing the surveillance could cause perturbations to the electrical distribution system that could challenge continued steady state operation and, as a result, plant safety systems.

The licensee provided the following discussion in the LAR to justify why the mode restrictions for SR 3.8.1.10 for Division 3 DG are not necessary:

- This test is performed by inserting an ECCS initiation signal into the Division 3 control logic (e.g., by arming and depressing the HPCS manual initiation pushbutton on the main control room panel). With the ECCS initiation signal present, the Division 3 DG starts and runs unloaded (generator output breaker is open) for ≥ 5 minutes while acceptable performance parameters (voltage and frequency) are verified. The HPCS pump start is manually overridden by placing the pump control switch in pull-to-lock, and opening of the motor-operated injection valve is prevented by verifying the valve is closed and de-energized (by placing the breaker for the valve motor in the OFF position). These steps are taken to prevent an actual discharge of water into the reactor vessel by the HPCS system, which could cause unwanted effects on reactor vessel water level. Similar steps would likewise be taken when performing this test online to preclude unwanted effects on reactor vessel water level and core reactivity due to an HPCS system injection. Following the test, restoration of all safety-related functions, including restoration of the HPCS system to operable status, are independently verified. Similar methods and procedural controls would be employed when performing the surveillance test online.

- The HPCS system is a stand-alone system with a dedicated DG and independent electrical distribution system. The simulated ECCS initiation signal is generated only in the HPCS logic and does not affect the other two safety-related electrical divisions. Thus, performing the SR 3.8.1.10 test for the Division 3 DG, whether shutdown or online, affects only the HPCS system.

- In addition, since this test is conducted with the Division 3 DG unloaded and isolated from its emergency bus, there is no impact to the electrical distribution system, and no mechanism for challenging continued steady state operation.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated November 2, 2009, and agrees that removal of mode restrictions (i.e., allowing the SR to be conducted in Mode 1 or 2) for Division 3 DG in SR 3.8.1.10 will have minimal impact on the safe operation of plant.

SR 3.8.1.11

SR 3.8.1.11 requires verification that the Division 3 DG automatic trips are bypassed on an actual or simulated loss of voltage signal on its associated 4.16 kV emergency bus concurrent

with an actual or simulated ECCS initiation signal, except for critical protective trip functions (engine overspeed and generator differential current). Currently, this SR contains a Note that prohibits performance in Modes 1, 2, or 3. The TS Bases state the reason for the Note is that performing the surveillance removes a required DG from service.

The licensee provided the following discussion in the LAR to justify why the mode restrictions for SR 3.8.1.11 for Division 3 DG are not necessary:

- This SR is not performed with the DG paralleled to offsite power.

- The HPCS system is a stand-alone system with its dedicated DG and independent distribution system. Performing the SR 3.8.1.11 tests for the Division 3 DG, whether online or shutdown, affects only the HPCS system, and there is minimal opportunity for the performance of these tests to have any impact on other safety-related plant equipment.

- The unavailability of the Division 3 DG that occurs during the conduct of these tests and the other SRs that are proposed to be performed online is well within the 14 days of inoperability that is allowed by the TS, and also does not challenge achievement of the administrative goal that has been established for Division 3 DG maintenance rule unavailability performance.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated November 2, 2009, and agrees that removal of mode restrictions (i.e., allowing the SR to be conducted in Mode 1, 2, or 3) for Division 3 DG in SR 3.8.1.11 will have minimal impact on the safe operation of the plant.

SR 3.8.1.14

SR 3.8.1.14 requires verification that the Division 3 DG can be synchronized with the offsite power source while loaded with emergency loads, and upon a simulated restoration of offsite power, all loads are transferred to offsite power and the DG returns to ready-to-load operation. Currently, this SR contains a Note that prohibits performance in Modes 1, 2, or 3. The TS Bases state the reason for the Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems.

The licensee provided the following discussion in the LAR to justify why the mode restrictions for SR 3.8.1.14 for Division 3 DG are not necessary:

- The HPCS system is a stand-alone system with a dedicated DG and independent electrical distribution system; thus, there is minimal opportunity for the performance of this SR to have any impact on other safety-related plant equipment or normal plant operation.

- Although the offsite source of power to the Division 3 emergency bus is disconnected at the beginning of this test, the period of time that this condition exists is small and is acceptable since the HPCS system is already inoperable for performance of the test.

- The relative size of the loads associated with the HPCS system (2540 kW) presents minimal potential for creating an offsite power supply perturbation when shifting the load between the Division 3 DG and the offsite power source. The offsite power source for the Division 3 4.16 kV emergency bus during the test is an RSST, regardless of whether the test is performed online or during shutdown conditions.

- Completed test results performed during shutdown conditions have shown that the required bus voltage parameters stay within expected limits and no anomalous actions regarding load transfer sequences occur. Based on past experience, conducting this test online will be no more challenging to plant safety systems than performance during shutdown conditions.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated November 2, 2009, and agrees that removal of mode restrictions (i.e., allowing the SR to be conducted in Mode 1, 2, or 3) for Division 3 DG in SR 3.8.1.14 will have minimal impact on the safe operation of the plant.

SR 3.8.1.15

SR 3.8.1.15 requires verification that, with the Division 3 DG operating in the test mode and connected to its 4.16 kV emergency bus, an actual or simulated ECCS initiation signal overrides the test mode by returning the DG to ready-to-load operation and automatically energizing the emergency loads from offsite power. Currently, this SR contains a Note that prohibits performance in Modes 1, 2, or 3. The TS Bases state the reason for the Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems.

The licensee provided the following discussion in the LAR to justify why the mode restrictions for SR 3.8.1.15 for Division 3 DG are not necessary:

- Performance of testing does not cause any significant perturbations to the electrical distribution system as the DG is separated from the bus.

- Similar to testing performed for SR 3.8.1.7 and SR 3.8.1.8, the power system loading for this test remains within the rating of the affected transformers, switchgear, and breakers.

- This test is performed by paralleling the DG in test with offsite power, similar to the existing monthly run of the DG (SR 3.8.1.3) that is conducted with the plant, which has no mode restriction.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated November 2, 2009, and agrees that removal of mode restrictions (i.e., allowing the SR to be conducted in Modes 1, 2, or 3) for Division 3 DG in SR 3.8.1.15 will have minimal impact on the safe operation of the plant.

SR 3.8.1.17

SR 3.8.1.17 requires verification that the Division 3 DG automatically starts from the standby condition on an actual or simulated LOOP signal in conjunction with an actual or simulated ECCS initiation signal, achieves the required voltage and frequency within the specified time, and supplies permanently connected loads for > 5 minutes. Currently, this SR contains a Note that prohibits performance in Modes 1, 2, or 3. The TS Bases state the reason for the Note is that performing the surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge plant safety systems.

The licensee provided the following discussion in the LAR to justify why the mode restrictions for SR 3.8.1.17 for Division 3 DG are not necessary:

- The HPCS system is a stand-alone system with a dedicated DG and independent electrical distribution system; thus, there is minimal impact from the performance of this SR on other safety-related plant equipment. The simulated LOOP and ECCS initiation signals affect only the HPCS system and do not affect the other two safety-related electrical divisions.

- Although the offsite source of power to the Division 3 emergency bus is disconnected for this test, the period of time that this condition exists is small and is acceptable since the HPCS system is already inoperable for performance of the test.

- Additionally, due to the relative size of the loads associated with the HPCS system (2540 kW), there is minimal potential for this testing to create an offsite power supply perturbation when the Division 3 electrical bus is de-energized. HPCS pump starts are routinely performed online to satisfy quarterly in-service testing requirements, without disturbing plant operation.

The NRC staff reviewed the above discussion in the LAR and the supplemental information provided by the licensee in its letter dated November 2, 2009, and agrees that removal of mode restrictions (i.e., allowing the SR to be conducted in Modes 1, 2, or 3) for Division 3 DG in SR 3.8.1.17 will have minimal impact on the safe operation of the plant.

3.2.3 Conclusion

The NRC staff evaluated the licensee's proposed change to the identified SRs of Division 3, HPCS system DG. The changes would remove mode restrictions on SR 3.8.1.7, SR 3.8.1.8, and SR 3.8.1.10 currently prohibited to be performed in Modes 1 or 2; the changes would also remove the mode restrictions on SR 3.8.1.9, SR 3.8.1.11, SR 3.8.1.14, SR 3.8.1.15, and SR 3.8.1.17 currently prohibited to be performed in Modes 1, 2, or 3, as applicable to Division 3 DG. Based on the above technical evaluation, the NRC staff concludes that the proposed TS changes will have minimal impact on the licensee's ability to continue to comply with the requirements of 10 CFR 50.36(c), GDC 17, and GDC 18. Therefore, the NRC staff considers the proposed changes in the LAR acceptable.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New York State official was notified of the proposed issuance of the amendment. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes SRs. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (June 16, 2009 (74 FR 28577)). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

6.0 CONCLUSION

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

Principal Contributor: V. Goel

Date: March 18, 2010

March 18, 2010

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

SUBJECT: NINE MILE POINT NUCLEAR STATION, UNIT NO. 1 - ISSUANCE OF AMENDMENT REGARDING RELOCATION OF PRESSURE AND TEMPERATURE LIMIT CURVES TO THE PRESSURE AND TEMPERATURE LIMITS REPORT (TAC NO. ME0817)

Dear Mr. Belcher:

The Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment No. 133 to Renewed Facility Operating License No. NPF-69 for the Nine Mile Point Nuclear Station (NMPNS), Unit No. 2 (NMP2), in response to your application dated March 30, 2009 (Agencywide Documents Access Management System (ADAMS) Accession No. ML090970277), as supplemented on November 2, 2009 (ADAMS Accession No. ML093140658).

This amendment modifies the NMP2 Technical Specification (TS) 3.8.1, "AC Sources – Operating," to remove operating mode restrictions for the performance of certain Surveillance Requirements (SRs) pertaining to the Division 3, High Pressure Core Spray (HPCS) Emergency Diesel Generator (DG). The testing in Modes 1 or 2 were previously prohibited in SR 3.8.1.7, SR 3.8.1.8, and SR 3.8.1.10, and in Modes 1, 2, or 3 in SR 3.8.1.9, SR 3.8.1.11, SR 3.8.1.14, SR 3.8.1.15, and SR 3.8.1.17. The amendment removes these Mode restrictions and allows the above SRs to be performed in any operating mode for the Division 3 DG. The Mode restrictions remain applicable to the other two safety-related (Division 1 and Division 2) DGs.

A copy of the related Safety Evaluation is enclosed. A Notice of Issuance will be included in the Commission's next regular biweekly *Federal Register* notice.

Sincerely,

/RA/

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

Enclosures:
1. Amendment No. 133 to NPF-69
2. Safety Evaluation

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ADAMS Accession No.: ML100460016
*SE provided by memo. No substantial changes made. ** Concurrence via e-mail NRR-106

OFFICE	LPL1-1/PM	LPL1-1/LA**	DE/EEEB/BC*	DIRS/ITSB/BC	OGC	LPL1-1/BC
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