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U-603399
8E.100e
August 08, 2000

Docket No. 50-461 10CFR50.90

Document Control Desk
Nuclear Regulatory Commission
Washington, D.C. 20555

Subject: Clinton Power Station Additional Information Regarding Proposed Amendment of Facility Operating License No. NPF-62 (LS-96-008)

Dear Madam or Sir:

By Letter U-603367 dated June 19, 2000, AmerGen Energy Company, LLC (AmerGen) requested amendment of the Clinton Power Station (CPS) Operating License (No. NPF-62) pursuant to 10CFR50.90. The amendment application, which is currently under review by the NRC staff, consists of proposed changes to the Technical Specifications to revise several of the Surveillance Requirements (SRs) pertaining to testing of the standby emergency diesel generators (DGs). The proposed changes would remove the restriction associated with the affected SRs that prohibits performing the required testing during Modes 1 and 2. The intent of the proposed changes is to provide greater flexibility in outage scheduling and to reduce critical path time during outages since the affected DG surveillance tests would be allowed to be performed during plant operation (as they would no longer be required to be performed only during an outage).

During its review of the proposed changes, the NRC staff recently determined that it requires additional information to complete its review. Specifically, several questions have been identified for which responses from AmerGen are requested. These questions were provided to Licensing personnel at CPS by facsimile on July 12, 2000 and then transmitted by followup letter from the NRC, dated July 21, 2000.

AmerGen's responses to the NRC staff's questions are hereby provided in the attachment (Attachment 2) to this letter. Each question is provided for reference, followed immediately by the associated response. The responses to the questions support the

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Technical Specification changes as proposed, so that this follow-up letter to AmerGen's June 19, 2000, amendment application involves no change to the changes proposed in the amendment application, nor to the Basis for No Significant Hazards Consideration.

Sincerely yours,

Michael T. Coyle
Vice President

TBE/mlh/blf

Attachments

cc: NRC Clinton Licensing Project Manager
Regional Administrator, USNRC Region III
NRC Resident Office, V-690
Illinois Department of Nuclear Safety

Attachment 1
To U-603399
LS-96-008

AFFIRMATION

Michael T. Coyle, being first duly sworn, deposes and says: That he is Vice President for Clinton Power Station; that this response to an NRC request for additional information has been prepared under his supervision and direction; that he knows the contents thereof; and that the letter and the statements made and the facts contained therein are true and correct to the best of his knowledge and belief.

Date: This 8TH day of August 2000.

Signed: Michael T. Coyle
Michael T. Coyle
Vice President

STATE OF ILLINOIS)
} SS.
DEWITT COUNTY)

" OFFICIAL SEAL "
Thomas B. Elwood
Notary Public, State of Illinois
My Commission Expires 11/29/2001

Subscribed and sworn to before me this 8TH day of August 2000.

Thomas B. Elwood
(Notary Public)

Questions and Responses

Reference: NRC Letter dated July 21, 2000, "Clinton Power Station, Unit 1 – Request for Additional Information (TAC No. MA9269)"

1. **Provide a discussion of the following postulated events associated with the EDG start signals during the EDG 24-hour load run test at power:**

   a. **loss-of-offsite power (LOOP)**
   b. **safety injection (SI)**
   c. **LOOP with SI**

Response

a. Loss-of-offsite power (LOOP) – In response to a LOOP during emergency diesel generator (DG) testing (i.e., with the DG running and paralleled to the offsite power source via the associated 4 kV bus), the DG would attempt to supply power to the loads on the safety-related 4 kV bus and the loads (or fault) on the grid (assuming the grid remains connected to the bus). Because the grid loading greatly exceeds the DG capability, bus voltage and frequency would drop significantly. The DG would momentarily respond by raising generator field current via its voltage regulator to support the bus voltage and by increasing the fuel supply to the engine via its governor to support the bus frequency. This response, however, would have a negligible effect on restoring the grid and would eventually lead to an actuation of either the first-level undervoltage relays or the DG voltage-restrained overcurrent relays, as further described below.

In the event of an undervoltage condition, the first-level undervoltage relays would trip the main or reserve feed breaker to separate the bus from the grid. When this occurs, the DG would then be able to maintain bus voltage and frequency in the specified range. It should be noted that for the Division 3 DG, the 4 kV bus frequency would remain slightly elevated following a LOOP event because of the manual droop setting on the governor for the Division 3 DG. However, the operating and surveillance procedures direct the operators to restore frequency to its acceptable range following a LOOP event by using the governor "raise" and "lower" switches in the main control room.[1]

In the event of a sustained overcurrent condition, the DG voltage-restrained overcurrent relays would energize an auxiliary relay. This auxiliary relay would immediately trip the main or reserve feed breaker for the respective divisional bus to separate the bus from the grid and energize a time-delay relay. The time-delay relay is designed to trip the DG output breaker if the

[1] The potential impact of the droop setting during testing of the Division 3 DG was addressed in License Amendment 119 to the CPS Operating License. The amendment approves operator action for meeting the "ready-to-load" requirement for the Division 3 DG.

overcurrent condition exists longer than the time setting of the auxiliary relay. However, for the overcurrent condition caused by the LOOP, the DG output current would drop below the setpoint of the overcurrent relay upon opening of the main or reserve feed breaker (well before the overcurrent relay time delay would time out), thereby not initiating a DG output breaker trip signal and allowing the DG to continue supplying power to the bus. (Again, for the Division 3 DG, manual operator action could be required to restore DG frequency to the acceptable range.)

b. Safety Injection (SI) – For a loss-of-coolant accident (LOCA) with SI during DG testing, the DG response is as described in USAR Section 8.3.1. That is, the DG test mode is overridden by the SI actuation signal such that upon receipt of the SI actuation signal, the DG output breaker will trip open and the Reserve Auxiliary Transformer (RAT) or the Emergency Reserve Auxiliary Transformer (ERAT) will continue to supply power to the connected loads. The DG will continue to operate at nominal speed and voltage in a standby condition and would be capable of automatically connecting to its 4 kV bus should there be a subsequent LOOP event. This capability (for the SI actuation signal to override the DG test mode and return the DG to a ready-to-load condition) is periodically verified by performance of the testing required by Technical Specification (TS) Surveillance Requirement (SR) 3.8.1.17.

It should be noted that, in response to the SI actuation signal, droop control on the DG voltage regulator and the electronic governor will automatically switch over to the isochronous mode of operation as required by IEEE 387, "Standard Criteria for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Power Generating Stations." This ensures that the DG will run at rated speed when supplying the bus on its own after separating from the offsite power source. Again, an exception to this description is the manual droop control for the mechanical governor on the Division 3 DG, as previously described, i.e., as addressed in Amendment 119 to the CPS Operating License.

It may also be noted that, for all three DGs, non-critical protective trips are bypassed on a LOCA signal to preclude spurious trips of the DG(s).

c. Consideration of a LOOP occurring with a LOCA (SI initiation signal), while a DG is in a test mode, involves a highly improbable combination of events or conditions. Certain sequences that could be postulated for such a highly improbable scenario would be considered to be beyond the design or licensing basis of the facility. Notwithstanding, given such an unlikely scenario, the response of a DG to a LOOP and SI while the DG is in test (i.e., paralleled to the offsite power source) is dependent on which of the two events/conditions (LOOP or LOCA) occurs first (or whether the two events/conditions are assumed to occur simultaneously). For the case when a DG is under test, and

the LOOP follows or occurs simultaneously with the LOCA, there is no impact to proper loading of the DG because either of the following will occur:

(1) For a LOCA occurring while the DG is in test, followed by a LOOP, the LOCA (SI initiation) signal will override the test mode and immediately ensure the DG is brought to a ready-to-load condition, as described previously. (That is, the DG will be in a standby condition, running at rated speed and voltage, with the DG output breaker ready to close onto the bus on demand.) Upon occurrence of the subsequent LOOP, the DG output breaker will close the DG onto the bus, and the associated plant loads (Engineered Safety Feature (ESF) equipment) will be sequenced onto the bus via the associated delay timers (which prevent the simultaneous starting of the large ESF motors, thus precluding overloading of the DG per the plant design).

(2) For a LOCA occurring simultaneously with a LOOP, while the DG is in test, the LOCA (SI initiation) signal will override the test mode and open the DG output breaker (to return the DG to a ready-to-load condition). As soon as the DG output breaker permissive logic is satisfied (i.e., the DG is at rated speed and/or voltage, the associated offsite source circuit feed breakers are open, and no voltage is sensed on the bus by the first level/loss-of-voltage bus relays), the DG output breaker will close to supply power to the bus, and the associated plant loads (ESF equipment) will be sequenced onto the re-energized bus via the associated delay timers, as described above.

For a postulated event where the LOOP precedes the LOCA (SI initiation), availability of the DG cannot be entirely assured. As described earlier, occurrence of the LOOP will cause a significant drop in bus voltage and a large increase in DG output current that results in a trip of the main or reserve feed breaker from either the first level undervoltage relays or the voltage-restrained overcurrent relays. Tripping these breakers removes the overload or the effect of the fault from the offsite source and allows the DG to supply power to its safety-related bus. However, availability of the DG is dependent on the timing of the LOCA signal following the LOOP and on whether the main or reserve feed breaker is tripped by the undervoltage relay or the voltage-restrained overcurrent relays. In particular, the timing of these relays relative to the timing of time-delay (sequencing) relays that control the closing of the feed breakers for certain large ESF motors (i.e., the shutdown service water (SX) system pump motors) can cause DG loading to occur differently than anticipated for licensing basis events. This is described further as follows.

In the event of a bus undervoltage relay trip, the time delay relay in the closing circuit for the Shutdown Service Water (SX) system pump motor breaker will drop out and reset. At the same time, the non-safety Service Water (WS)

system pumps that normally supply cooling water to the safety-related loads will trip on the LOOP, thereby causing a loss of WS pressure. A pressure switch in the WS piping header for each SX division will then sense the low WS pressure and initiate a start signal to the respective SX pump motor breaker. Once the DG restores bus voltage, and after a 10-second time delay, the time delay relay energizes the closing coil of the SX pump motor breaker. In the event of a SI initiation signal being received concurrent with a LOOP, this logic sequence normally ensures the start of the SX pump motor is delayed until after the start of other large ESF motors (in accordance with the intended load sequence for the associated DG) but in sufficient time to provide cooling water for the DG. Thus, the DG remains available with a LOOP preceding a bus undervoltage relay trip with a LOCA initiation signal.

However, intended load sequencing for the DG may not occur if the SX pump motor receives a start signal from the SX pressure switch before the SI initiation relay. In this particular scenario, the SX pump motor will start on low WS pressure exactly 10 seconds after its safety-related bus voltage is restored by the DG, regardless of the SX pump start signal that may be received on a subsequent SI initiation signal. Thus, if the SI initiation signal occurs at approximately the same time as when the time-delay relay energizes the breaker closing coil of the SX pump motor, the SX pump motor and a large ECCS pump motor will start simultaneously and may cause the DG to trip on overload due to the high motor starting currents. On the other hand, if the SI initiation signal is received 5 seconds after the SX time delay relay times out, sequencing of the ESF loads with the SX pump motor will not be simultaneous and the DG will not be overloaded.

In response to a voltage-restrained overcurrent relay trip, the DG will restore bus voltage before the undervoltage relay trip. Consequently, the time delay relay in the closing circuit for the SX pump motor breaker remains energized, thereby allowing the breaker to close without delay once the WS low pressure switch start signal is received for the SX pump motor. Should the SI signal occur at approximately the same time as the overcurrent relay trip, the SX pump motor may start simultaneously with the start of the ESF equipment and could cause the DG to trip on overload (similar to the above scenario). On the other hand, if the LOCA initiation signal is received more than 5 seconds after the voltage-restrained overcurrent relay trip, sequencing of ESF equipment will occur after the SX pump motor has already started and the DG will not be overloaded.

Based on the above, the DG may be rendered unavailable only under a particular sequence of events where the DG is in the test mode when a LOOP event occurs causing a trip of the voltage-restrained overcurrent relay before the undervoltage relay, followed shortly by a LOCA initiation. This postulated event is an event of extremely low probability (9.48 E-8/year) and therefore can be excluded as a potential contributor to DG unavailability[2]. Further, the above-described sequence can only occur for a DG under test. Since only one DG is tested at a time, the remaining divisions powered by the other DGs would not be affected.

2. **Could the proposed change to surveillance testing at power prevent the EDG being tested from appropriately responding to an accident, i.e., LOOP? If yes, provide the risk impact, in terms of the change in core damage frequency and a single outage risk (i.e., ICCDP: incremental conditional core damage probability in RG 1.177), due to unavailability of the EDG for surveillance testing at power rather than at shutdown.**

Response: Yes, during certain portions of the surveillances the DG would not be able to immediately respond to an accident. DG unavailability during the performance of the proposed on-line DG testing is summarized in the Table entitled "DG Unavailability During Surveillance Testing." (See page 6 of 9.)

To summarize, the independent overspeed test (Table Item 6) has the most unavailability time of 1.5 hours. However, this unavailability time is not continuous since the test is performed in segments such that maximum single interval of unavailability time is 0.5 hours. The combined Overcrank, Differential Current, and Bypassed Trips Test (Table Item 2) has the longest uninterrupted (sustained) period of DG unavailability of one hour. Based on this, the greatest Incremental Conditional Core Damage Probability (ICCDP) in RG 1.177 is determined as follows:

For the average maintenance model (as specified in RG 1.177), the base core damage frequency determined for CPS is 2.6E-5 per year. Of the three diesel generators, the Division 3 DG has the largest risk achievement worth. The core damage frequency with the Division 3 DG out of service is 4.51E-5. Therefore, the largest delta core damage frequency (CDF) for this proposal occurs with the Division 3 DG out of service and is (4.51E-5 – 2.6E-5) 1.91E-5. Using this value with the longest interval of 1.0 hours yields (1.91E-5 times 1/8766) 2.18E-9 per year. This is significantly smaller than the threshold of 5E-7 per year provided as a guideline in RG 1.177.

[2] The analysis of the expected frequency of the LOOP during DG testing with a delayed LOCA is provided in Attachment A.

DG Unavailability During Surveillance Testing

	Surveillance Test Procedure/ Description	Applicable CPS Technical Specification	Associated Unavailability	Comments regarding unavailability
1	CPS 9080.13, .14 (24-hour DG Run with Hot Restart)	SR 3.8.1.14	0.3 hrs/DG/cycle	Unavailability estimate is based on the average time to bar engine over and check for moisture in cylinders
2	CPS 9080.21, 22 (Division 1, 2 DG Overcrank Test, Differential Current Test, and Bypassed Trips Test)	SR 3.8.1.13	1.0 hrs/DG/cycle	Unavailability estimate is based on the average time to install toggle switch for LOCA signal and to conduct testing. The DG remains unavailable until the Overcrank test, Differential overcurrent test, Trip bypass operability test are completed and the lockout relay (86 device) and exciter field circuit breaker (41 device) are reset.
3	CPS 9080.23 (Division 3 DG Bypassed Trips Test)	SR 3.8.1.13	0.3 hrs/DG/cycle	Unavailability estimate is based on the average time to install toggle switch for LOCA signal and to conduct testing.
4	CPS 9080.23 (Division 3 DG Differential Current Relay Trip Test)	SR 3.8.1.13	0.3 hrs/DG/cycle	Test is performed with the load rejection test. The DG is shut down by tripping the differential current relay. Unavailability estimate is based on the estimated time for resetting the lockout relay (86 device).
5	CPS 9080.30 (Division 1, 2 DG Overspeed Trip Test)	SR 3.8.1.13	1.0 hrs/DG/cycle	Unavailability estimate is based on the time (0.5 hr) to bar engine and check for moisture and to perform the overspeed trip solenoid verification (cross-tripping capability of the 12- and 16-cylinder engines) and the time (0.5 hr) to reset the lockout relay (86 device) and the exciter field circuit breaker (41 device) following the overspeed trip of the DG set.
6	CPS 9080.31 (DG Independent Overspeed Trip Test, Division 1 and 2 only)	SR 3.8.1.13	1.5 hrs/DG/third cycle	This procedure is performed in lieu of CPS 9080.30 every third cycle. Additional unavailability time (0.5 hr) is due to the individual verification of the overspeed trip solenoid for each engine.
7	CPS 9080.30 (Division 3 DG Overspeed Trip Test)	SR 3.8.1.13	0.5 hrs/DG/cycle	Unavailability estimate is based on the average time to bar the engine and check for moisture and to reset the lockout relay (86 device) following overspeed.
8	CPS 9080.21, .22, .23 (Full Load Rejection Test, Single Largest Load Rejection Test, Test Mode Override Test)	SR 3.8.1.9, SR 3.8.1.10, SR 3.8.1.17	0.5 hrs/DG/cycle	Unavailability estimate is based on the average time to install toggle switch to simulate LOCA signal and to bar engine and check for moisture.
			Total Unavailability Hours per cycle **Division 1, 2:** **2.8 hrs/DG/cycle, or 3.3 hrs/DG/third cycle** **Division 3:** **1.9 hrs/DG/Cycle**	

3. Are there any plans for restricting additional maintenance or testing of required safety systems, subsystems, trains, components and devices that depend on the remaining EDG as a source of emergency power? If not, discuss the reasons for not having these restrictions.

Response Technical Specification Requirements

The Technical Specifications themselves impose requirements/restrictions on the required equipment and features associated with the redundant division (i.e., the division(s) associated with the DG(s) not under test) when a DG is inoperable (including being made inoperable for testing or maintenance). Specifically, when a diesel generator becomes inoperable in Mode 1, 2, or 3, Required Action B.2 of TS 3.8.1, "AC Sources – Operating," requires identification of inoperable required features that are redundant to required features supported by the inoperable diesel generator. This Required Action is applicable throughout the entire period of diesel inoperability. Inoperable features on the redundant division can then cause entry into other or more severe Required Actions, thus providing further incentive not to make a DG inoperable whenever a required feature(s) on the redundant division(s) is inoperable. Required Action B.2 is intended to provide assurance that the occurrence of LOOP, during the period that a DG is inoperable, does not result in a complete loss of safety function of critical systems.

The Safety Function Determination Program (SFDP) pursuant to TS 5.5.10 is used to ensure that there is no loss of a safety function as a result of removing equipment from service for maintenance or testing, with regard to the relationship between support and supported systems or functions as addressed by TS LCO 3.0.6.

On-Line Risk Assessment

Notwithstanding the requirements of the Technical Specifications, on-line scheduling and coordination of work activities at CPS is procedurally controlled through CPS 1151.01, "On-Line Work Management Process." This procedure links the steps of the work control process, including assessing on-line risk consistent with the requirements of 10CFR50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants (i.e., the Maintenance Rule)." CPS Procedure 1151.12, "On-line Risk Assessment," governs the process for assessing on-line risk. The identified purposes of this procedure include outlining the requirements for assessing, monitoring and maintaining acceptable levels of on-line risk; outlining requirements for performing reviews and evaluations of work schedules prior to implementation; and, providing guidance to determine the safety implications of removing equipment from service for performance of on-line maintenance as required by 10CFR50.65.

On-line risk assessment assures that defense-in-depth is provided for the duration of the on-line maintenance. This assessment includes a detailed examination of the on-line maintenance schedule including system interactions, support system availability, and impact of temporarily installed equipment.

To address the concern of whether there are plans for restricting additional maintenance or testing of required safety systems, subsystems, trains components, and devices that depend on the remaining EDG as a source of emergency power, CPS 1151.12 contains provisions for assessing risk levels. One of these provisions is to use risk assessment tools (i.e., risk meter) to analyze on-line risk. These tools are used to identify the level of risk associated with the scheduled activities. Green (minimal), yellow (acceptable), orange (high), and red (unacceptable) risk levels are defined in CPS 1151.12. In accordance with the procedure, consideration should be given to the risk level in determining when to perform the activities.

4. Are there any plans to preclude performing the requested surveillance at power during other maintenance and test conditions that could have adverse effects on the offsite power system? If not, discuss the reasons for not having these restrictions.

<u>Response</u> Consistent with the response to Question 3 above, CPS 1151.12 contains specific provisions for assessing activities occurring in the switchyard that increase the potential for a loss of offsite power or a loss of power to the Reserve Auxiliary Transformer (RAT) to occur. Further, considerations are given to changing the risk levels to the next higher category when conditions exist that could cause the plant to be at higher risk levels, such as, tornado watches or warnings, severe thunderstorm watches or warnings, a 345-kV line out of service, or work being performed on one of the lines. The results of the CPS on-line risk assessment may identify that, if the risk level is high enough, contingency plans need to be established to maintain on-line safety at an acceptable level, or that the activities need to be re-scheduled if unacceptable levels are identified.

5. What would be the typical and worst-case voltage transients on the medium voltage safety bus as a result of a full-load rejection?

<u>Response</u> The perturbation on the medium-voltage safety bus during a DG full-load rejection test would be nearly proportional in magnitude to the voltage peaks on the 4 kV safety bus. Using data taken from past full-load rejection tests that were performed prior to installation of the Static Var Compensators (SVCs), the initial voltage dip on the 4 kV bus ranged from a minimum of 59 volts (1.4% of nominal) during a Division 2 DG test in July 1998 to a maximum of 341 volts (8.1% of nominal) during a Division 3 DG test in November 1996. Based on this actual test data, the initial voltage dips for the medium-voltage buses would range between 2 and 10 volts at the 120V level, and between 7 and 39 volts at the 480V level.

Voltage on the medium-voltage safety buses during testing would thus remain above the minimum required transient voltage for plant loads, and would stabilize shortly after the disturbance (i.e., in less than 2 seconds, consistent with the voltage stabilization observed on the 4 kV bus). The voltage transient experienced by the loads on the 4 kV, 480V and 120V buses during DG full-load rejection testing is therefore minor.

It may be noted that with the associated SVC in service, voltage perturbations are further minimized due to the compensating effect of the SVC. With the SVC controlling, the bus voltage quickly recovers to the voltage setpoint of the SVC. This compensating effect was demonstrated in a recent full-load rejection test on the Division 3 DG with the SVC in service, where the transient voltage dip was only 35 volts on the 4 kV bus, and the bus voltage recovered to the SVC setpoint voltage in 0.4 seconds.

Analysis of Frequency of a Loss of Offsite Power (LOOP) During Diesel Generator (DG) Testing with a Loss of Coolant Accident (LOCA)

To calculate the frequency of occurrence of a LOOP during the time a DG is paralleled with an offsite source, the total number of hours a DG is paralleled (per year) is determined as follows. For each 18-month cycle, the total number of hours a single DG is paralleled with an offsite source is 28, based on the number of hours of parallel operation required to perform all applicable surveillances during an operating cycle. On an annual basis, and accounting for three DGs, this equates to 84 hours per 12 months, or expressed as a fraction of the year, 0.00958 of the total time.

Frequency of a LOOP during DG Testing

If a LOOP and the time when a DG is paralleled with the offsite power source are considered to be independent events or conditions, then the frequency ($F_{\text{LOOP during DG testing}}$) of occurrence of these combined events is as follows:

$$F_{\text{LOOP}} \quad \times \quad \begin{bmatrix}\text{Fraction of} \\ \text{DG online testing}\end{bmatrix} \quad = \quad F_{\text{LOOP during DG testing}}$$

$$0.0332\text{/year} \quad \times \quad 0.00958 \quad = \quad 0.000318\text{/year}$$

The above value for F_{LOOP} (frequency of occurrence of a LOOP) is as determined in the Clinton Power Station PRA.

To couple the above frequency with the frequency of a LOCA, the LOCA is conservatively considered to be a LOOP-induced LOCA. (Treating the LOCA as an independent event would yield a much lower frequency for the combined events.) Thus, for the purpose of this analysis, the frequency of a LOOP-induced LOCA is postulated. This event would be a LOOP causing a reactor scram, followed by a failure of all 16 safety relief valves (SRVs) to open, leading to a LOCA caused by significant reactor overpressurization. For a LOOP-induced LOCA, the common cause failure probability of all 16 SRVs failing to open on demand is 2.98E-4.

Frequency of a LOOP-induced LOCA during DG Testing

$$\begin{bmatrix}\text{Probability of all} \\ \text{SRV's failing} \\ \text{to open}\end{bmatrix} \quad \times \quad F_{\text{LOOP during DG testing}} \quad =$$

$$0.000298 \quad \times \quad 0.000318\text{/year} \quad = \quad 0.0000000948\text{/year}$$

or 9.48 E-8/year