**FENOC**

FirstEnergy Nuclear Operating Company

Perry Nuclear Power Plant
10 Center Road
Perry, Ohio 44081

Mark B. Bezilla
Vice President

440-280-5382
Fax: 440-280-8029

October 13, 2011
L-11-333

10 CFR 50.90

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

SUBJECT:
Perry Nuclear Power Plant
Docket No. 50-440, License No. NPF-58
Supplemental Information for License Amendment Request Regarding Offsite Electric Power System Acceptability until December 12, 2011 (TAC No. ME7263)

By letter dated October 11, 2011, FirstEnergy Nuclear Operating Co. (FENOC) submitted a license amendment request to revise the Perry Nuclear Power Plant (PNPP) Technical Specifications to temporarily use a delayed access circuit as one of the required offsite circuits between the offsite transmission network and the onsite Class 1E alternating current (AC) electric power distribution system. On October 11, 2011, the Nuclear Regulatory Commission (NRC) staff identified the need for additional information to support review of the license amendment request. Attachment 1 to this letter provides the necessary information as a supplement to the original request. On October 12, 2011, the NRC staff identified the need for additional information to support review of the license amendment request. Attachment 2 to this letter provides the necessary information as a supplement to the original request. Attachment 3 provides a revised Technical Specification resulting from an NRC question.

In response to a telephone conversation with NRC staff on October 12, 2011, FENOC provides the following information related to the proposed amendment.

The onsite and offsite electric power systems are designed to provide power to the systems and components necessary to mitigate the consequences of a loss-of-coolant accident (LOCA). The onsite power system is not affected by this change and will continue to perform its design function to mitigate an accident. A single instantaneous offsite circuit is designed to be available within a few seconds following a LOCA to assure that core cooling, containment integrity, and other vital safety functions are maintained. Compensatory measures committed to in the letter dated October 11, 2011; further minimize risk to the availability of the instantaneous offsite circuit during the time period allowed by the proposed change. Because the available onsite power system is not affected, the offsite circuit is capable of providing sufficient power, and risk to the offsite circuit has been minimized, power will still be available as required to mitigate an accident.

The proposed amendment involves the use of a backfeed electrical alignment to temporarily meet the requirements of TS 3.8.1 to maintain the availability of offsite power. The compensatory measures associated with the amendment maintain the reliability of offsite AC electrical sources and ensure timely alignment of the delayed access circuit. These measures ensure continued availability of the offsite power system. The proposed amendment does not involve any change to the onsite power system, so the onsite power system reliability and redundancy is not affected. Since the proposed change does not affect the availability of the offsite or onsite power system, the systems will continue to provide power as required during shutdown as well as reactor power operation.

There are no regulatory commitments contained in this submittal. If there are any questions or if additional information is required, please contact Mr. Phil H. Lashley, Supervisor- Fleet Licensing, at (330) 315-6808.

I declare under penalty of perjury that the foregoing is true and correct. Executed on October 13, 2011.

Sincerely,

Mark B. Bezilla

Attachments:
1. Supplemental Information Requested October 11, 2011
2. Supplemental Information Requested October 12, 2011
3. Revised Technical Specification Page

cc: NRC Region III Administrator
NRC Resident Inspector Office
NRC Project Manager
Executive Director, Ohio Emergency Management Agency (NRC Liaison)
Utility Radiological Safety Board

The following information is provided to supplement a license amendment request (LAR) for the Perry Nuclear Power Plant (PNPP) regarding temporary use of a delayed access circuit in the offsite electric power system until December 12, 2011. The Nuclear Regulatory Commission (NRC) staff questions are presented in bold type, followed by the FirstEnergy Nuclear Operating Company (FENOC) responses.

1. **Startup Transformer Information**
   a. **The Unit 1 Startup Transformer had failed on February 5, 1996, as a result of a spurious fire protection system deluge actuation, had been sent offsite for repairs. Once initial repairs were completed, the transformer failed its post-repair testing and had to be rewound. Why was the initial failure attributed to fire protection system deluge actuation? Are the two Startup Transformers exposed to inclement weather conditions which could result in water spray similar to deluge system? Why did the transformer fail the post-repair test? Has the Unit 2 Startup transformer been rewound or had major repairs since its installation at the plant?**

   Response: In the initial occurrence, a relay in the deluge circuitry failed resulting in actuation of the deluge on the Unit 1 startup transformer. The corrective action program root cause evaluation determined that the combination of energized equipment and impure water (lake water) sprayed over the bushing and transformer surfaces during freezing conditions created an electrically conductive path from the 345kV termination point at the top of the bushing (C phase) to the grounded metal case of the transformer. Once this path was established, the resultant flashover caused the destruction of the transformer bushing, and the actuation of the startup transformer differential and lockout protective relays.

   Both the Unit 1 and Unit 2 startup transformers are exposed to outdoor weather conditions. The Unit 1 startup transformer is further north than the Unit 2 startup transformer and may be less shielded from prevailing strong winds than the Unit 2 startup transformer but both are outdoors near their respective Turbine buildings. Deluge system nozzles were redirected away from the transformer bushings on both startup transformers as an action from the root cause investigation.

   With respect to the post-repair test failure, discussions with personnel involved in refurbishment of the Unit 1 startup transformer indicated there was no direct cause of the testing anomalies determined at the vendor shop. The decision was made to rewind the transformer.

   With respect to the Unit 2 startup transformer, it experienced a fault due to a high side bushing arc to the tank on October 2, 2000. The "A" and "B" phase bushings were missing the required corona rings. All three bushings were replaced and the corona rings were installed. The transformer has not been rewound.

**b. The Unit 1 Startup Transformer unexpectedly failed at 0529 on September 29, 2011. It is staff's understanding the same transformer had been taken out of service for trouble shooting less than 24 hours earlier. Provide details on the problems identified prior to the unexpected failure of the transformer on September 29, 2011. Provide results of preliminary findings related to the unexpected failure on September 29, 2011. Explain why the Startup Transformer Unit 2, that is currently in operation, is not susceptible to same failure, considering it has similar operating history. Provide details on gas analyses or other tests performed prior to declaring the transformer operable on September 28, 2011. Provide details of gas analyses trending that has been performed over the last five years for both Start Up Transformers, the unit auxiliary transformer and the main transformer.**

Response: Prior to the unexpected failure of the Unit 1 startup transformer, the transformer had been returned to service from a general maintenance activity (preventive maintenance, rather than troubleshooting). The general maintenance included:

1. Examining the following items for oil leaks, oil level, operability, tightness of connections and damage as applicable:
   a. Lightning arrestors
   b. Bushings
   c. Transformer tank
   d. Heat exchanger
   e. Fan motors
   f. Oil pumps
   g. Line connections

   Provisions were provided for cleaning as required and to add oil to the transformer as needed.
2. Inspecting power cables and termination compartment for signs of degradation, electrical tracking, loose connections, moisture intrusion, and overall general condition of electrical components.
3. Cleaning resistor banks of dust or obstructions.
4. Visually inspecting resistor bank wiring for loose connections.
5. Inspecting joints on fan blades for rust and cracks.
6. Cleaning bushings, arrestors, etc. where needed.
7. Verifying inspection cover(s) are properly sealed after reinstallation.
8. Verifying/ensuring that the control panel door is properly sealed for water intrusion. Replacing door gaskets as required.

Calibration of several relays was also performed. A corrective action to inspect the bushing connections for transition plates and remove if found was also performed.

These general maintenance and calibration tasks were completed satisfactorily and no adverse findings were related to this general maintenance.

The scope of work performed just prior to the failure of the Unit 1 startup transformer was general maintenance. Therefore, only functional testing such as ensuring power is supplied to the transformer coolers and the coolers were placed in the "manual" position was performed. Proper operation of the fans was verified and the fans were stopped after completion of the checks. Panel heaters were also verified to be functioning properly.

Preliminary results related to the unexpected failure of the Unit 1 startup transformer on September 29, 2011 are:

1. Arc damage was observed on the bottom of the "B" phase bushing
2. The pump header on the outside of the tank had a weld seam that failed causing tank deformation
3. Internal inspection identified no abnormal conditions with the windings
4. The "B" corona shield was bent
5. An arc mark was identified on the tank from the fault
6. Transformer Turns Ratio (TTR) testing was satisfactory
7. Post failure oil analysis confirmed a thermal fault condition

Testing and investigation currently remain in progress.

As discussed in the response to item 1a above, in October 2000, the Unit 2 startup transformer experienced a fault from the "B" phase bushing. All three high side bushings were replaced and new corona rings were installed. The root cause of Unit 1 startup transformer failure is indeterminate as the root cause investigation is ongoing. However since the Unit 2 startup transformer has been in service since May 2010 combined with gas analyses results that have been in accordance with IEEE C57.104-2008 this transformer is not expected to fail.

The industry has identified the need to look beyond traditional preventative maintenance practices and consider an on-line bushing monitoring system as a means of failure detection, since current practices may not be sufficient. The PNPP staff is investigating the installation of on-line bushing monitors as an additional means of predictive maintenance.

Details of the gas analyses trending that has been performed over the last five years for both startup transformers, the unit auxiliary transformer and the main transformer is available for inspection but is not included here due to the volume of information.

c. **Provide details on the loading of the Startup Transformers during normal operation and during refueling outages.**

Response:

Based on the trend data for the last five years, the typical loading for both startup transformers is as follows.

| Transformer | Online Loading | Refueling Loading |
|---|---|---|
| Unit 1 Startup | 8-9MW | 18-22MW |
| Unit 2 Startup | 4-6MW | 4-6MW |

Occasionally, the electrical alignment is temporarily altered such that the either startup transformer may carry all of the Unit I and Unit 2 loads. Primarily this occurs when the transformer is down-powered to perform maintenance. Typically, maintenance on the startup transformers would be performed with the plant online; therefore, the expected loading on the in-service transformer supporting all of the loads would be 12-15 MW. If either startup transformer were out of service during an outage period (that is, worst case loading) the in-service transformer would supply a load of 22-28 MW.

2. **Backfeed Voltage Drop Analysis Information**

   a. **Provide a summary of assumptions made for the backfeed analyses.**

Response: The analysis of the backfeed configuration is documented in a calculation entitled "PNPP Class 1E Power Distribution System Voltage Study." The backfeed case assumes the PNPP minimum grid voltage of 96.5% of 345kV, with the maximum post-loss-of-coolant accident (post-LOCA) automatic plant loading. Where possible, loading was skewed to Division 1 Engineered Safety Feature (ESF) bus EH11. Therefore, the most limiting bus voltages would be the Division 1 ESF buses.

b. **Provide an overview of the loads at each bus that were used for the load flow study.**

Response: The loads that were used as inputs to the Electrical Transient Analyzer Program (ETAP) software include load categories such as battery chargers, hydramotors, induction motors (running items such as pumps, fans and chillers throughout the plant), motor-operated valves (MOVs) in various systems throughout the plant, lumped loads (such as non-safety transformers), and static loads (such as heating coils, ignitors, radiation monitors, and control room lighting panels).

c. **Given the existing settings of the degraded voltage relays, what is the corresponding minimum voltage required at the 345kV switchyard busses assuming the plant is in normal shutdown configuration with**

**required non safety and safety-related loads in operation? Provide results of N-1 contingency analyses performed to evaluate the 345kV switchyard bus minimum voltage for worst case winter loading on the transmission network supplying offsite power to the Perry nuclear plant.**

Response: The minimum grid voltage for PNPP is 96.5% of 345kV (332,925 volts). The degraded voltage relay (DVR) setpoints are calculated to be 3730V for dropout and 3854V pickup, with a 12 second timer when a LOCA signal is present. The "PNPP Class 1E Power Distribution System Voltage Study" calculation contains motor starting analysis with the grid at 96.5% of 345kV and demonstrates that the degraded voltage relays will not drop out long enough (greater than 12 seconds) for the ESF buses to be automatically transferred to the emergency diesel generators (EDGs). The calculation also analyzes post-LOCA loading conditions and demonstrates that post-LOCA ESF bus voltage will be above the degraded voltage relay reset value. The post-LOCA loading is greater than the normal shutdown loading, and therefore, has a more negative impact on the ESF bus voltage measured by the DVRs. Based on this, a minimum grid voltage of 96.5% will ensure adequate voltage to the ESF buses and DVRs under all loading conditions, including the normal shutdown configuration.

With respect to the N-1 contingency analysis, the summer loading for the transmission network supplying PNPP is actually higher and more bounding than the winter loading, and therefore the summer loading is used for the N-1 contingency analysis performed by FirstEnergy Service Company. Based on summer of 2011 results, none of the postulated 345kV bus voltages fell below the PNPP minimum of 96.5% of 345kV. The lowest voltage postulated is 99.4% of 345kV. Therefore, the Summer 2011 assessment supports Perry's minimum grid voltage used in the "PNPP Class 1E Power Distribution System Voltage Study."

3. **Offsite Power Backfeed Path**

   a. **Condition report CR-2011-03236 related to annunciator problems at Perry switchyard. Provide details on the type of alarms and why their malfunction is acceptable for plant operation.**

Response: On October 11, 2011, a walk down and test of Perry switchyard breaker alarms was performed. A PNPP Operations Shift Manager and Cleveland Electric Illuminating company operator conducted the test. Results were:

- Breaker S612 - 4 of 13 alarm windows work
- Breaker S610 - 0 of 17 alarm windows work
- Breaker S611 - 8 of 13 alarm windows work
- Breaker S652 - All alarm windows work
- Breaker S650 - All alarm windows work
- Breaker S662 - All alarm windows work

- Breaker S660 - All alarm windows work
- Breaker S661 - All alarm windows work
- Breaker S622 - All alarm windows work
- Breaker S620 - All alarm windows work
- Breaker S621 - All alarm windows work
- General Alarm Panel - 19 of 20 alarm windows work

The types of alarms on the breakers are:

- Breaker Trip Failure
- Eight alarms associated with various SF6 gas system parameters
- Additional alarms are breaker-specific that indicate trouble on equipment or the transmission line on either side of the breaker.

Other indications on these breakers include protection relay status and indication of each phase of the breakers status as open or closed.

Plant operation is acceptable with the associated alarm issues based on the other indications available on the breaker panels to diagnose breaker faults (protection relay status and breaker position indication). These diverse indications would be used to identify and isolate a fault in the transmission yard and coordinate with the System Control Center (SCC) for restoration of electrical power to the switchyard.

**b. Perry nuclear power plant has initiated following condition reports related to the components in the backfeed circuit: CR 2011-09603, CR 2011-96158, CR 2011-96312, CR 2011-96315, and CR 2011-96318. Provide details on the deficiencies identified and the actions taken to ensure the components can be operated as designed in the event that backfeed path has to be aligned for supplying plant safety buses.**

Response:

Condition Report (CR) 2011-96043 documents a broken clutch pin lock. A smaller lock was provided that will not interfere with the disconnect switch. Cosmetic damage was listed in this CR, which is a broken top half of the de-clutch guide to place switch S112 in the maintenance condition of de-clutched. This condition is minor and does not adversely impact the operating function of the S112 switch.

CR 2011-96158 identified that the main generator disconnect switch can not be opened electrically. The "A" phase was not engaging properly. Notification 600689053 was written to track rework of the switch. The CR was closed as a duplicate to CR 2011-96312.

CR 2011-96312 also identified the deficiencies with the S112 main generator disconnect switch. Order 200463325 was created to resolve the issue that prohibits the main generator disconnect switch from closing electrically and to resolve the switch misalignment in the "A" phase. Order 200463325 was worked in the September 29, 2011 forced outage operating the S112 switch both manually and electrically. Order 200463325 is closed indicating the required functions have been restored.

CRs 2011-96315 and 2011-96318 were closed as duplicates to CR 2011-96312.

c. **Describe how the time study referenced in the license amendment request has been validated through a human performance study (i.e., actual performance of the procedure). Also provide the time assumed to perform each activity in the backfeed procedure (i.e., 'Off-Site Power Restoration').**

Response: The time study was re-validated at the end of September 2011. It was performed from the plant simulator with eleven operators, and oversight from three training instructors. The operations staff included a Shift Manager, Unit Supervisor, Shift Engineer, three Reactor Operators (RO), and five non-licensed operators (NLO). The time study validated the time from a loss of offsite power event (loss of power to safety buses EH11, EH12, and EH13) until power is restored via the backfeed lineup. With offsite power considered to be degraded, a transient occurs [spurious opening of a safety relief valve (SRV)], the plant is scrammed, and when the turbine trips, a complete loss of offsite power occurs. Two scenarios were examined. One assumes only a startup transformer is lost, but power remains available in the transmission yard, such that a walkdown of the transmission yard is not necessary (as it is when all power in the transmission yard is lost), and there is no need to contact the System Control Center (SCC) to request re-powering of the grid at PNPP. This scenario took an average of 89 minutes to complete:

| Event | Time after Time Zero |
|---|---|
| Time until a reactor operator was directed to perform the Off-Normal Instruction ONI-SPI F-1, "Offsite Power Restoration" | 23 Minutes |
| Time until a plant operator was directed to perform the Off-Normal Instruction ONI-SPI F-2, "Yard Inspection" (Transmission) | 25 Minutes |
| Time until an NLO completes the transformer yard inspections (Note: these are different than transmission yard inspections) | 61 Minutes |
| Time until an NLO is able to manually open main generator disconnect S-111, using the scaffolding | 79 Minutes |

| | |
|---|---|
| Time until a reactor operator is able to complete ONI-SPI F-1, "Offsite Power Restoration" instruction by energizing safety bus EH11 via the backfeed lineup from main transformer | 89 Minutes |

If, instead, additional component failures are assumed such that power from all four pathways into the transmission yard are considered to be lost in addition to the startup transformer, the scenario took an average of 129 minutes to complete:

| Event | Time after Time Zero |
|---|---|
| Time until an reactor operator was directed to perform ONI-SPI F-1, "Offsite Power Restoration" | 23 Minutes |
| Time until a plant operator was directed to perform the Off-Normal Instruction ONI-SPI F-2, "Yard Inspection" (Transmission) | 25 Minutes |
| Time until an NLO completes transformer yard inspections (Note: these are different than transmission yard inspections) | 61 Minutes |
| Time until an NLO completes a Transmission Yard inspection and reports on the completion of this task to the Control Room and the SCC | 91 Minutes |
| Time until an NLO is able to manually open main generator disconnect S-111, using the scaffolding | 109 Minutes |
| Time until a reactor operator is able to complete ONI-SPI F-1, "Offsite Power Restoration" instruction by energizing safety bus EH11 via the backfeed lineup | 129 Minutes |

d. **When crediting the delayed access circuit, the licensee states that direct current (DC) power would be available for reactor core isolation cooling system and manual safety relief valve operation which will preclude fuel cladding or reactor coolant pressure boundary damage for four hours. Describe the condition of the plant assumed in the design basis calculations for supporting this statement and how the DC system has been demonstrated by test to be capable of performing this design function.**

Response: A DC battery capacity calculation performed in support of station blackout (SBO) analyses selectively combines assumptions from both an SBO event and a loss-of-offsite power (LOOP)/loss-of-coolant accident (LOCA) event to bound the DC loading profiles. The calculation assumes no available offsite circuits, no normal or reserve battery chargers, and that the Division 1 and 2 diesel generators are not available.

DC loads during an SBO would not be very high since not all the DC powered support equipment would be running, because there would be no AC power to the engineered safety feature (ESF) buses and their emergency systems (such as low pressure coolant injection pumps and supporting emergency service water pumps). Therefore, the calculation conservatively uses the load profiles from the two-hour LOOP/LOCA event calculations. Although PNPP continues to maintain and test the batteries from both Unit 1 and Unit 2 in support of Unit 1 operation, only one unit's batteries are normally aligned, therefore, the calculation assumes that for the first 35 minutes, only a single unit's batteries are aligned. After 35 minutes, both the Unit 1 and Unit 2 batteries for Division 1 are considered to be cross-tied, which increases overall battery system capacity. The same assumption is made for Division 2 after 35 minutes.

With respect to testing, the service testing is individually performed for each of the batteries (Unit 1, Division 1; Unit 2, Division 1; Unit 1, Division 2; and Unit 2, Division 2). These service tests use the load profiles from the two hour LOOP/LOCA event, again assuming no battery charger availability. Since each battery is tested under these more heavily loaded LOOP/LOCA conditions, each can easily be shown to be capable of supporting two hours of the lighter SBO loads. Therefore, once the Unit 1 and 2 batteries are cross-tied within each division, it can be concluded that the cross-tied batteries will be capable of providing DC power to the specified systems for at least the four hour postulated SBO event.

4. **Please provide a basis for the requested 60-day time period for the one time amendment.**

   Response: The major activities required to be completed within the requested 60-day time period, some of which are proceeding in parallel, are:

   1. Procurement of required parts such as linear couplers, insulators, and current transformers.
   2. Transportation permit requirements for movement of the replacement transformer from the Davis Besse Nuclear Power Station to the PNPP to address railway requirements and county road requirements.
   3. Vacuum processing of the transformer which can typically take from 4-12 days, and in some situations longer, depending on moisture content in the transformer.
   4. Design of the deluge system piping to meet National Fire Protection Association (NFPA) code for the replacement Unit 1 Startup Transformer and procurement of the specified materials to construct the required deluge configuration.
   5. Redesign and construction work on the low voltage buswork arrangement, supports, and terminations that will require procurement of a larger low voltage cabinet.

The following information is provided to supplement a license amendment request (LAR) for the Perry Nuclear Power Plant (PNPP) regarding temporary use of a delayed access circuit in the offsite electric power system until December 12, 2011. The Nuclear Regulatory Commission (NRC) staff questions are presented in bold type, followed by the FirstEnergy Nuclear Operating Company (FENOC) responses.

1. **According to the Perry UFSAR [USAR], the plant design includes a Division 3 Diesel Generator, High Pressure Core Spray Power Supply (HPCS) that can be aligned to Division 1 or Division 2 busses in the event of a Station Blackout (SBO). Provide details on the capability of this AC source to power safe shutdown loads on Division 1 or Division 2 busses. Provide an overview of procedures, training, timeline and other guidance, including limitations that may be available to plant operators in the event that Division 3 Generator has to be aligned to Division 1 or Division 2.**

   Response: The Division 3 to Division 1 and Division 3 to Division 2 cross-tie alignments occur at the 480 volt AC (VAC) power level; the cross-ties are not 4160 VAC power sources for Division 1 or Division 2 safe shutdown loads.

   The FENOC procedure for the Division 3 to Division 1 cross-tie is intended to provide 480 VAC power for the Division 1 hydrogen igniters and two feedwater header isolation valves. Closure of these valves, one at a time, support initiation of the feedwater leakage control system, should initiation of this system be required. The FENOC procedure for the Division 3 to Division 2 cross-tie is intended to provide 480 VAC power to the Division 2 hydrogen igniters and a select number of containment isolation valves. Closure of these valves, one at a time, may be required for leak isolation. Per the procedures, it will take approximately 30 minutes to complete either 480 VAC cross-tie. Plant reactor operator limitations include the normal Division 3 emergency diesel generator operating parameters, as prescribed within its operating procedures, and the 'close one valve at a time' criterion. Non-licensed operators (NLOs) receive periodic training to perform the cross-tie activities. For the NLOs, this training was received during the current training cycle that ended October 6, 2011. Licensed reactor operators (ROs), including senior reactor operators (SROs), receive design basis station blackout (SBO) and total loss of AC power (TLAC) training at least once per two-year cycle. For the ROs and SROs, simulator training for loss of AC power was received during the training cycle that ended August 11, 2011. Classroom training for ROs and SROs on loss of AC power was received during the training cycle that ended October 6, 2011.

2. **The Battery system has additional redundancy available from the DC system that was originally intended for Unit 2. Provide details on the additional safety margin that is available in the DC system that can be used for coping with a SBO event.**

   Response: The Division 1, Unit 1 battery [1R42-S0002], Division 1, Unit 2 battery [2R42-S0002], Division 2, Unit 1 battery [1R42-S0003] and Division 2, Unit 2 battery [2R42-S0003] are all 60-cell batteries. A FENOC calculation concluded that the batteries have adequate voltage and capability to operate the required direct current (DC) loads for the 4-hour design basis SBO event.

   Per the calculation, battery sizing and load evaluations were performed per the guidelines of IEEE 485-1997, Section 6.4 and Appendix A, Figure A.4. Additionally, the 4-hour battery cell/terminal voltage was calculated per the guidelines of IEEE 485-1997, Appendix C, Table C.2, based upon the projected required load profile.

   Per the calculation, utilizing design margin, aging factor and temperature correction, the required number of positive plates per cell to support the SBO event is 2.33 positive plates per cell for both Division 1 batteries. The Division 1 batteries have 7 positive plates per cell. Thus, there is 200 percent positive plate margin for Division 1. Similarly, per the calculation, the Division 2 batteries require 1.86 positive plates per cell to support the SBO event. The Division 2 batteries also have 7 positive plates per cell. Thus, there is 276 percent positive plate margin for Division 2.

   Per the calculation, Unit 1 batteries will supply the required DC loads for the first 35 minutes of the SBO event. Per FENOC procedures, the Unit 1 and Unit 2 batteries will be cross-tied and operating in parallel after 35 minutes.

   Therefore, the existing Unit 1 and Unit 2 battery system has adequate capability and margin to cope with the SBO event.

1. **FENOC states that cause of the failure (Unit 1 SUT) is under investigation and that there have been no indications that FENOC could have reasonably anticipated the transformer failure. Regulatory Commitment number 5 states that the health of Unit 2 SUT will be monitored on a regular basis and degradation indicating potential failure will result in a controlled failure [shutdown]. If the failure of the Unit 1 SUT could not have been reasonably anticipated, what Unit 2 SUT indications will provide the licensee with the indications of potential failure of the Unit 2 SUT can be reasonably anticipated?**

Response: Unit 2 startup transformer indications will continue to be monitored according to Table 1, "Dissolved Gas Concentrations" parameters, results, and the corresponding status recommendations in IEEE C57.104-2008. Dielectric strength and moisture content will be monitored in accordance with the Table 5 "Suggested limits for continued use of service-aged insulating oil" in IEEE C57.106-2006.

2. **FENOC proposes that the delayed offsite circuit be clarified to be a temporary qualified alternative circuit and provided proposed temporary TS. The LAR, in part, states:**

   **Based on the following evaluation, it has been determined that the requirements in PNPP TS 3.8.1, "AC Sources - Operating," for having two qualified offsite sources can be met utilizing any two of the following three circuits:**
   **1) Unit 1 Startup Transformer (SUT)**
   **2) Unit 2 Startup Transformer (SUT)**
   **3) Backfeeding through the Main and Auxiliary Transformers**

   **The temporary TS, however, do not limit a single-failure acceptability of the delayed offsite power source since a single failure of the L10 bus would prevent both the Unit 1 SUT and the auxiliary transformer (delayed-source) from being capable of powering the Class 1E busses (EH11, 12, and 13) if the Unit 2 SUT is the inoperable offsite source. Therefore, the delayed source can only be considered as an alternate offsite source for the Unit 1 SUT and the proposed TS must be revised reflect this limitation.**

   Response: The proposed Technical Specification (TS) wording is being revised to read "Until December 12, 2011, a delayed access circuit may be used in place of the circuit associated with the Unit 1 startup transformer."

3. **For the TS 3.8.1 qualified offsite circuits, SR 3.8.1.1 requires a 7-day frequency to "ensure proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power." Please demonstrate applicability and provide acceptable performance history of SR 8.3.1.1 [SR 3.8.1.1] for the backfeed circuit.**

   Response: At PNPP, Technical Specification (TS) Surveillance Requirements (SRs) such as SR 3.8.1.1 are verified to be met by the performance of surveillance instructions (SVIs). The SVI used to meet SR 3.8.1.1 requires the operators to document the plant electrical lineup capabilities for each breaker, disconnect, power indicating light, and bus, noting its status (open or closed, light on or off, bus voltage) and, as applicable, its capability to change state ('can be opened' and 'can be closed'). The terms 'can be opened' and 'can be closed' are defined within the SVI as follows: "An electrical device (e.g., breaker or disconnect switch) can be opened (or closed) if control power is available and there are no known equipment problems with the device." The SVI also explains that:

> With regards to generator disconnect switch S111, credit may be taken for "can be opened" by manual operation if the following are met:
>
> - Means of access established (i.e., – ladder/scaffold erected)
> - Required tools/procedures are staged (TB-624 electrical locker)
> - Personnel expected to be called upon to manually operate switch S111 have been properly briefed for the activity.

The procedure then requires the operators to step through a flow chart, using the data they collected, to confirm that the required number of offsite circuits is available, down to each of the divisional ESF electrical buses. In cases where the 'can be opened' or 'can be closed' provisions are necessary, such as for the backfeed lineup, the SVI requirements can be met through the use of these provisions.

A review of previous operating history from the plant narrative log was performed. As other questions requested five years of data, this information is provided back to 2006. Verification of back-feed availability as a qualified offsite circuit to meet TS 3.8.1 was noted as shown below, prior to removal of either the Unit 1 or Unit 2 startup transformer from service:

| | | |
|---|---|---|
| 04/10/06 | Unit 1 Startup declared inoperable | verified back-feed available |
| 06/05/06 | Unit 2 Startup declared inoperable | verified back-feed available |
| 07/05/06 | Unit 1 Startup declared inoperable | verified back-feed available |
| 09/04/07 | Unit 2 Startup declared inoperable | verified back-feed available |
| 09/26/07 | Unit 1 Startup declared inoperable | verified back-feed available |
| 10/13/07 | Unit 2 Startup declared inoperable | verified back-feed available |
| 06/29/08 | Unit 1 Startup declared inoperable | verified back-feed available |
| 09/22/08 | Unit 2 Startup declared inoperable | verified back-feed available |
| 10/22/08 | Unit 1 Startup declared inoperable | verified back-feed available |
| 10/24/08 | Unit 2 Startup declared inoperable | verified back-feed available |
| 07/13/09 | Unit 1 Startup declared inoperable | verified back-feed available |
| 07/27/09 | Unit 2 Startup declared inoperable | verified back-feed available |
| 08/17/09 | Unit 1 Startup declared inoperable | verified back-feed available |
| 05/24/10 | Unit 2 Startup declared inoperable | verified back-feed available |
| 09/26/11 | Unit 1 Startup declared inoperable | verified back-feed available |

4. **The LAR states that transformer failure rates are significantly higher after being de-energized and re-energized. What source is this statement based upon and how does the history of the Unit 2 SUT correlate to this data.**

Response: This statement was based on a qualitative assessment relative to initial transient states (cycling) of larger equipment to that of continuous steady state operation. This assessment considered the cycling of larger equipment and the introduction of stress related factors (larger current forces during energization when compared to steady state operation) during the warmup/startup cycle and additionally considered the potential for human induced failures introduced during the maintenance activity (the maintenance-induced failure mechanism is not typically reported in the failure rate data). From the general component reliability perspective, the probability of a mechanical component to start (failure to start) typically has a higher failure rate than a mechanical component's failure to run (failure to run) failure rate (NUREG/CR 6928 "Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants"). This same logic was applied to the transformer which also contains mechanical components.

With respect to the history of the Unit 2 startup transformer, the Unit 2 startup transformer has been in steady state, continuous operation since May 2010.

Attachment 3
Revised Technical Specification Page

(1 Page Follows)

## 3.8 ELECTRICAL POWER SYSTEMS

### 3.8.1 AC Sources-Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electric Power Distribution System; and

b. Three diesel generators (DGs).

-----NOTE-----
Until December 12, 2011, a delayed access circuit may be used in place of the circuit associated with the Unit 1 startup transformer.
---------------

APPLICABILITY: MODES 1, 2, and 3.

-----NOTE-----
Division 3 AC electrical power sources are not required to be OPERABLE when High Pressure Core Spray System is inoperable.
---------------

ACTIONS

-----NOTE-----
LCO 3.0.4.b is not applicable to DGs.
---------------

| CONDITION | REQUIRED ACTION | COMPLETION TIME |
|---|---|---|
| A. One required offsite circuit inoperable. | A.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuit. | 1 hour<br><br><u>AND</u><br><br>Once per 8 hours thereafter |
| | <u>AND</u> | |

(continued)