UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
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LISLE, IL 60532-4352

March 27, 2012

Mr. Michael J. Pacilio
Senior Vice President, Exelon Generation Company, LLC
President and Chief Nuclear Office (CNO), Exelon Nuclear
4300 Warrenville Road
Warrenville, IL 60555

SUBJECT: BYRON UNIT 2 - NRC SPECIAL INSPECTION TEAM (SIT) REPORT 05000455/2012008

Dear Mr. Pacilio:

On February 13, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed a reactive inspection pursuant to Inspection Procedure 93812, “Special Inspection” at your Byron Station, Unit 2. The enclosed inspection report documents the inspection results, which were discussed on February 13, 2012, with Mr. Tim Tulon and other members of your staff.

The special inspection was commenced on January 30, 2012, in accordance with NRC Management Directive 8.3, “NRC Incident Investigation Program,” and Inspection Manual Chapter 0309, “Reactive Inspection Decision Basis for Reactors,” based on the initial risk and deterministic criteria evaluation made by the NRC on January 30, 2012.

The special inspection reviewed the circumstances surrounding the January 30, 2012, electrical insulator failure in the Byron switchyard that resulted in a Unit 2 automatic reactor trip and Notice of Unusual Event emergency declaration.

The inspectors examined activities conducted under your license as they relate to safety and compliance with the Commission’s rules and regulations and with the conditions of your license.

No findings were identified during this inspection.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Steven West, Director
Division of Reactor Projects

Docket No. 05000455
License No. NPF-66

Enclosure: Inspection Report 05000455/2012008
w/Attachments:
1. Supplemental Information
2. Special Inspection Team Charter
3. Timeline of Events

cc w/encl: Distribution via ListServ

U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket No.:	50-455
License No.:	NPF-66
Report No.:	05000455/2012008
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Unit 2
Location:	Byron, IL
Dates:	January 30, 2012 – February 13, 2012
Inspectors:	J. Benjamin, Senior Resident Inspector, Team Lead, DRP C. Moore, Operator Licensing Examiner, DRS M. Munir, Reactor Inspector, DRS
Observer:	J. Draper, Reactor Engineer, DRP
Approved by:	S. West, Director Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

Inspection Report 05000455/2012008; 01/30/2012 – 02/13/2012; Byron Station, Unit 2; Special Inspection.

This report covers a 15-day period of onsite inspection and offsite review from January 30, 2012, through February 13, 2012. A three-person team comprised of the Braidwood Senior Resident Inspector, a Region III Reactor Inspector, and a Region III Operator Licensing Examiner conducted the inspection using Inspection Procedure 93812, “Special Inspection.” The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 4, dated December 2006.

A. NRC-Identified and Self-Revealed Findings

None.

B. Licensee-Identified Violations

None.

REPORT DETAILS

Event Description

On January 30, 2012, a nonsafety-related (NSR) electrical insulator failed in the Byron 345 kilovolt (kV) switchyard that resulted in a Unit 2 automatic reactor trip and Notice of Unusual Event (NOUE) emergency declaration. The failed insulator physically supported the “C” phase electrical conductor; one of three electrical phases supplying 345kV to the two Unit 2 station auxiliary transformers (SATs). The loss of the Unit 2 SATs resulted in an inoperable Technical Specification (TS) preferred backup power source for Unit 1 until restoration on January 31, 2012. Unit 1 remained at 100 percent power and was not affected by this event.

Following the insulator failure, Byron Unit 2 automatically tripped from full power due to an undervoltage condition on NSR 6.9kV Bus 258 and Bus 259 that supply power to two of four reactor coolant pumps (RCPs). About 30 seconds after the Unit 2 reactor trip, the power source for 6.9kV RCP Bus 256 and Bus 257 and NSR 4kV Bus 243 and Bus 244 automatically fast transferred from the Unit 2 unit auxiliary transformers (UATs) to the (degraded) SATs. As a result, the remaining two RCPs tripped on an overcurrent condition due to the increased current flow through the “A” and “B” phases as a result of the open “C” phase.

The loss of the “C” phase, however, did not result in an automatic undervoltage protection signal for either safety-related (SR) 4kV engineered safety feature (ESF) Bus 241 or Bus 242 due to a design vulnerability (i.e., Bus 241 and Bus 242 were not designed to be protected from a single phase loss of either the “A” or “C” phase). As a result, all running and standby SR equipment powered from Bus 241 and Bus 242 was rendered inoperable and unavailable. This included the centrifugal charging (CV) system which supplied RCP seal injection, the component cooling water (CC) system which supplied RCP seal cooling, and the essential service water (SX) system. These conditions existed until manual operator action to separate from the degraded offsite power by opening the SAT feeder breakers was initiated from the main control room about 8 minutes following the start of the event.

Following the manual action to separate from offsite power, Bus 241 and Bus 242 de-energized and both emergency diesel generators (DGs) started and sequenced ESF equipment onto Bus 241 and Bus 242 as designed. No significant degradation to the RCP seals occurred based on the manual action occurring within the time it would have taken for the RCP seal water volume to deplete (estimated to be about 13 minutes). Reactor decay heat was removed utilizing the 2B (diesel-driven) auxiliary feedwater (AF) pump and steam generator (S/G) power-operated relief valves (PORVs) while the primary system cooled down in the natural circulation mode of operation. On January 31, 2012, Unit 2 entered Mode 5, Cold Shutdown.

During the event a number of other issues occurred that were addressed by the licensee. These included a water hammer on the secondary side of the plant, a plugged reactor coolant filter, and the wetting of the 2A residual heat removal (RHR) pump motor from a water leak.

The licensee remained in the NOUE until repairs were completed and the Unit 2 SATs were returned to their normal alignment on January 31, 2012.

Inspection Scope

A Special Inspection was initiated following the NRC’s review of the deterministic and conditional risk criteria specified in NRC Management Directive 8.3, “NRC Incident Investigation Program.” The inspection was conducted in accordance with NRC Inspection

Procedure (IP) 93812, “Special Inspection,” and the Special Inspection Charter (Attachment 2). The inspectors utilized information from the plant computer and sequence of events recorder; interviewed licensee personnel who responded to the event; performed physical walkdowns of plant equipment and the switchyard; reviewed procedures, maintenance records, and various technical documents; and reviewed corrective action program documentation and causal evaluations. A list of specific documents reviewed is provided in Attachment 1.

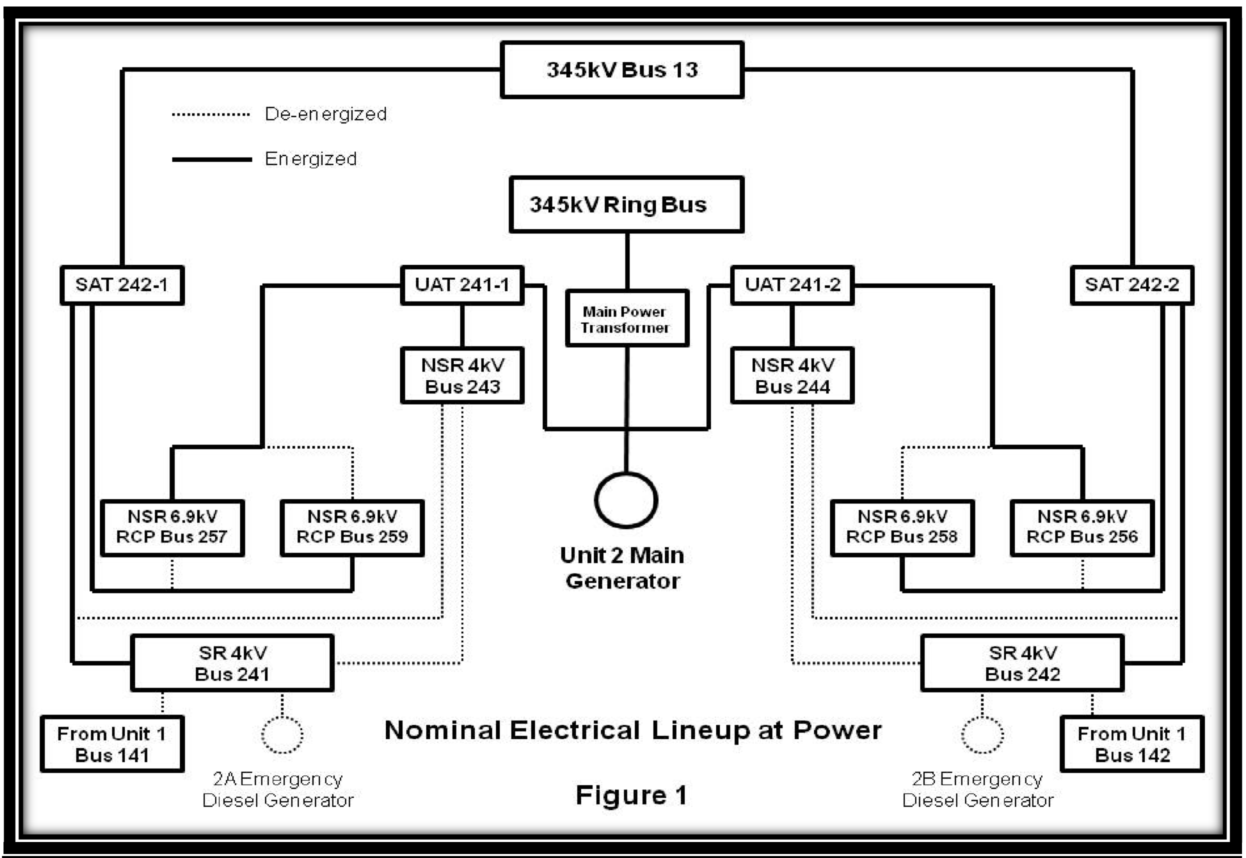
Byron Unit 2 Electrical Design Overview

Description of Unit 2 Power Sources (Figure 1)

The Byron Unit 2 electrical design includes 345kV lines that provide two credited NSR sources of preferred offsite power, and DGs that provide two independent SR sources of onsite power. In addition, the electrical design includes the capability to cross-tie Unit 1 SR ESF Bus 141 and Bus 142 to Unit 2 SR ESF Bus 241 and Bus 242.

The first offsite preferred power source is from 345kV Bus 13 to Unit 2 SATs 242-1 and 242-2. These SATs then supply NSR power to two RCPs through 6.9kV Bus 258 and Bus 259. The remaining RCP buses (Bus 256 and Bus 257) are powered from UATs 241-1 and 241-2. In addition to the 6.9kV buses, the Unit 2 SATs also supply power to SR Bus 241 and Bus 242.

The second offsite preferred power source is from 345kV Bus 6 through Unit 1 SATs 142-1 and 142-2 and through Unit 1 ESF Bus 141 and Bus 142 utilizing Unit 1 and Unit 2 cross-tie breakers.



Nominal Electrical Lineup at Power

Figure 1

Description of Unit 2 SR 4kV Bus 241 and Bus 242 Undervoltage Protection Scheme (Figure 2)

The Unit 2 undervoltage protection scheme for SR Bus 241 and Bus 242 is based on a two-out-of-two coincidence logic. Voltage sensing devices monitor Bus 241 and Bus 242 phase-to-phase differential voltage between the “A” and “B” phases (A-B phase voltage differential) and the “B” and “C” phases (B-C phase voltage differential). Because the undervoltage protection scheme utilizes contacts that are in series, an undervoltage trip signal is processed only if the voltage sensing device detects a differential voltage of less than 2730 Volts alternating current (Vac) for **both** the A-B and B-C phases. If only the “A” phase or “C” phase voltage is lost, then only one of two undervoltage contacts close, the undervoltage protection logic is not satisfied, and an undervoltage trip signal is not processed. The degraded voltage protection logic is of a similar design. The circuitry for receiving a Bus 241 and Bus 242 undervoltage or degraded voltage alarm in the main control room utilizes the same logic.

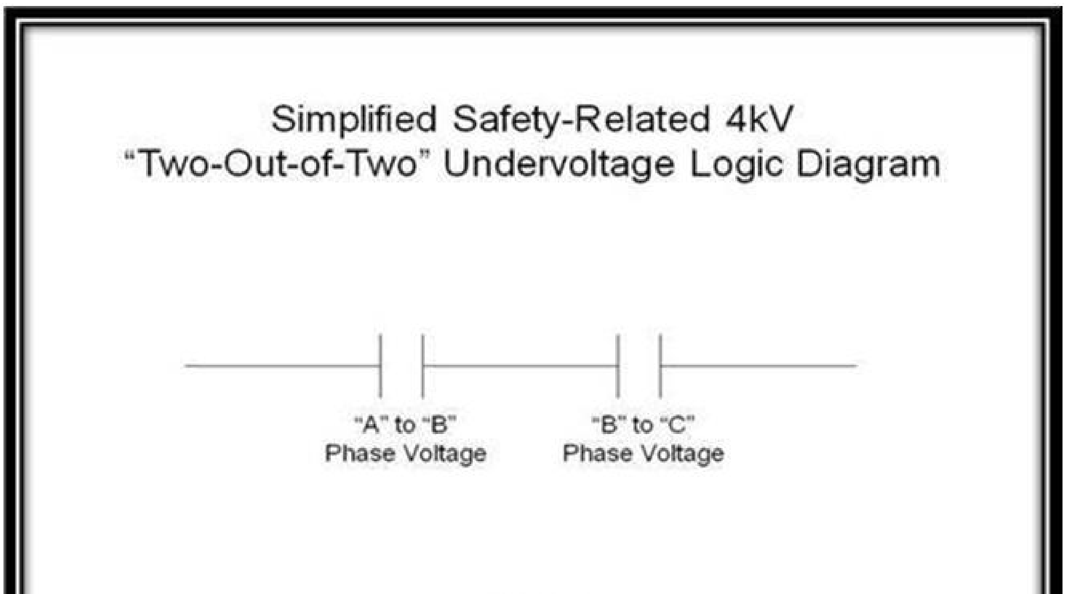


Figure 2

4OA5 Other Activities - Special Inspection (IP 93812)

.1 Establish a Sequence of Events (Charter Item 1)

a. Inspection Scope

The inspectors reviewed control room logs, plant parameter recordings, plant procedures, corrective action documents, maintenance work orders (WOs), and work request history as part of the inspection activities. The inspectors conducted interviews with licensed operators and other personnel who responded to the event to determine the sequence of events associated with the insulator failure and plant response for the January 30, 2012, Unit 2 reactor trip.

A narrative description of the event is provided below. A detailed timeline developed by the inspectors is also included as Attachment 3.

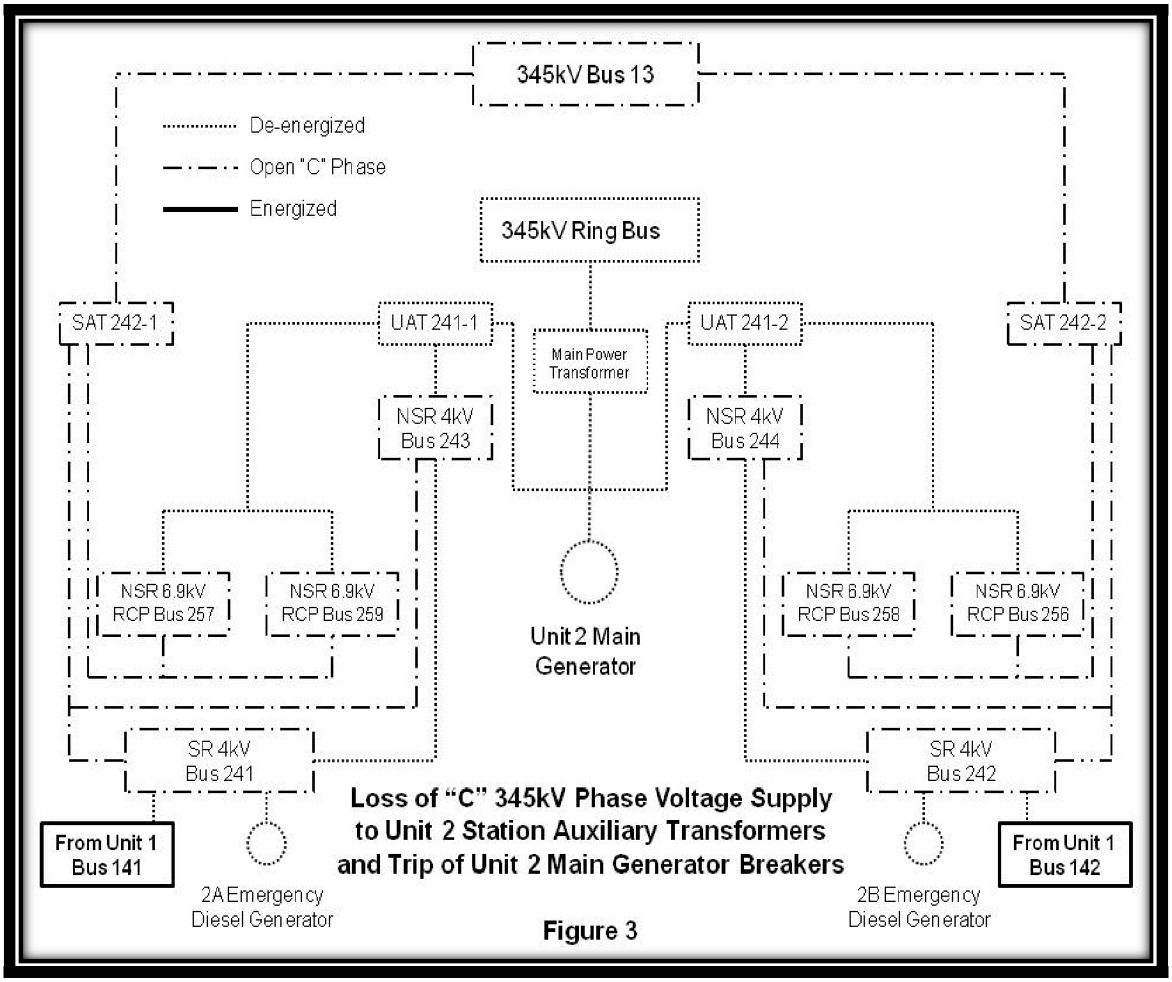
b. Findings

Detailed Narrative of the Event

On January 30, 2012, at 10:01 a.m., Byron Unit 2 automatically tripped from full power due to an undervoltage condition on 6.9kV Bus 258 and Bus 259 that supply power to two of the four RCPs. The undervoltage condition was caused when the “C” phase insulator stack for the Unit 2 SAT revenue metering unit broke and part of the insulator fell to the ground (Picture 1).

Picture 1

The broken insulator that was providing vertical support for the “C” phase conductor resulted in the conductor breaking and isolating the “C” phase 345kV supply to the Unit 2 SATs. This type of “open” failure did not result in a desired protective logic actuation for the SATs or switchyard ring bus. The SAT protective relays were designed to trip during a fault or overcurrent condition, neither of which occurred. The differential relays were designed to detect the differential current between the input and output current on a phase-to-phase basis. In this case, both input and output currents were zero, therefore the SAT feeder breakers did not trip open. With only the “A” and “B” phases energized, the Unit 2 SATs continued to supply degraded 6.9kV power to NSR Bus 258 and Bus 259, and degraded 4kV power to SR ESF Bus 241 and Bus 242.



Loss of “C” 345kV Phase Voltage Supply to Unit 2 Station Auxiliary Transformers and Trip of Unit 2 Main Generator Breakers

Figure 3

6.9kV Bus 258 and Bus 259 powered by the Unit 2 SATs sensed an undervoltage condition on the B-C phase. As a result, an automatic reactor protection signal was processed based upon a predictive loss of two of four operating RCPs. About 30 seconds following the reactor trip, 6.9kV Bus 256 and Bus 257 and NSR 4kV Bus 243 and Bus 244 automatically transferred from the Unit 2 UATs to the (degraded) Unit 2 SATs, as designed. With the open “C” phase supplying the Unit 2 SATs (and all RCP buses), the “A” and “B” phase currents supplying the RCPs increased, resulting in the remaining RCPs tripping on an overcurrent condition about 40 seconds after the transfer.

The loss of “C” phase voltage, however, did not result in automatic undervoltage protection for Bus 241 and Bus 242 due to an unknown design vulnerability (i.e., safety-related buses were not designed to be protected from a loss of the “A” or “C” phase voltage). Both trains of safety-related equipment powered from Bus 241 and Bus 242 tripped on overcurrent within seconds due to the inrush of current on the operating phase voltages. A total loss of seal cooling to all four RCPs occurred since both trains of CV were rendered inoperable and unable to supply seal injection and both trains of CC were rendered inoperable and unable to supply cooling water to the RCP thermal barrier heat exchangers.

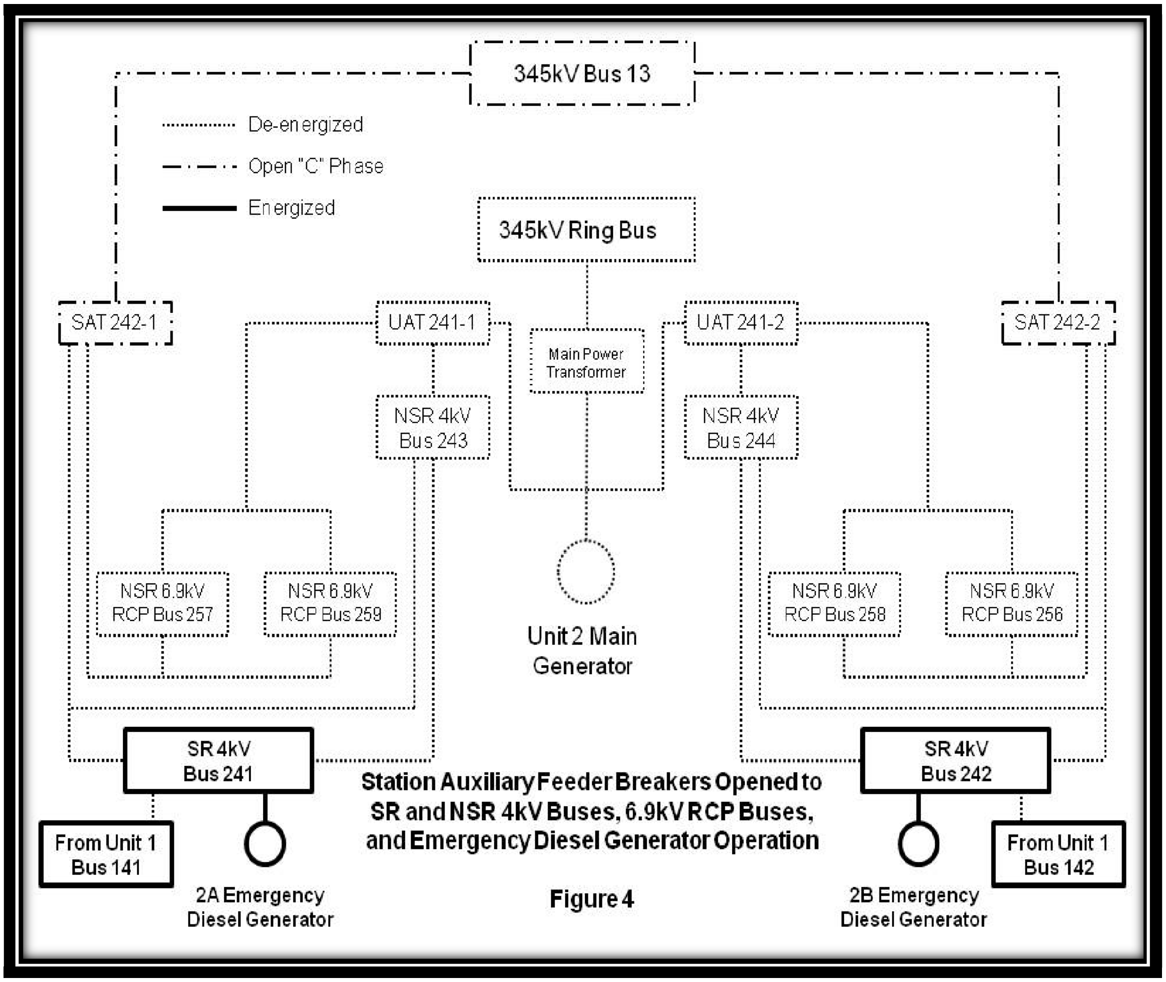
Reactor decay heat was removed from the secondary through the S/G PORVs with the primary operating in the natural circulation mode. These PORVs released steam directly to the atmosphere as designed. Feedwater makeup to the S/Gs was supplied by the 2B (diesel-driven) AF pump. The steam released contained extremely low levels of tritium.

Following the completion of procedurally required actions by control room operators in response to the reactor trip, a briefing was conducted to assess plant status prior to transitioning to the Reactor Trip Recovery procedure. Operators recognized that all equipment that was powered from Unit 2 NSR Bus 258 and Bus 259 and SR Bus 241 and Bus 242 had tripped. All equipment that was running had its respective 'trip disagreement light' lit as well as a stop indication on the main control board control switch. Operators observed the 2B AF pump running and providing adequate flow to the S/Gs. Additionally, operators observed that equipment powered from emergency direct current (DC) power was running.

At about 10:04 a.m., operators attempted to start the standby 2B SX pump, but the pump did not start due to the undervoltage condition. Operators then restored Unit 2 SX flow by opening SX system cross-connect valves between Unit 1 and Unit 2 and starting an additional Unit 1 SX pump.

Operators noted that there were no abnormal alarms lit associated with safety-related ESF power and the associated Bus 241 and Bus 242 "bus alive lights" were lit. The 4kV ESF bus voltages indicated 4kV for the ESF buses. However, when the bus voltage selector switch was switched from monitoring the A-B phase voltage to the B-C and C-A phase voltages, a potential undervoltage condition was immediately identified as both the B-C and C-A phase voltages indicated about 2.5kV. An auxiliary operator was subsequently dispatched to the Unit 2 SATs and reported seeing smoke from both SATs.

Based upon the operators' general understanding of an electrical issue resulting in equipment failing to run, lower than expected B-C and C-A phase voltages on the SR 4kV buses, and the report of smoke from the Unit 2 SATs, operators concluded that the voltage on the safety-related buses and condition of the Unit 2 SATs was not acceptable and at about 10:09 a.m. (8 minutes into the event) opened the SAT feeder breakers supplying offsite power to the SATs. After opening these breakers, the undervoltage logic was satisfied, and an ESF undervoltage protection signal was processed for Bus 241 and Bus 242. Accordingly, both DGs started and sequenced safety-related equipment onto Bus 241 and Bus 242, restoring normal plant shutdown components and systems, including RCP seal injection and seal cooling.



Station Auxiliary Feeder Breakers Opened to SR and NSR 4kV Buses, 6.9kV RCP Buses, and Emergency Diesel Generator Operation

Figure 4

At 10:18 a.m., the licensee declared a NOUE in accordance with the Byron Emergency Plan for a loss of offsite power to the Unit 2 SATs for greater than 15 minutes. At 10:23 a.m., the licensee reported this event to the Illinois Emergency Management Agency (IEMA) using the Nuclear Accident Reporting System (NARS).

At 10:23 a.m., based upon the report of smoke from the Unit 2 SATs, the licensee requested offsite assistance from the Byron Fire Department. At 10:48 a.m., two Byron Fire Department trucks entered the Protected Area (PA) and five trucks parked outside the PA as a standby resource. Upon further investigation, no actual fire occurred. The smoke from the Unit 2 SATs was caused by a sudden heatup of the SAT windings due to the inrush of current resulting from the open “C” phase. At 10:41 a.m., switchyard breakers 7-13 and 12-13 were opened to de-energize 345kV Bus 13 and the Unit 2 SAT high side windings.

Operators proceeded through the Reactor Trip Recovery procedure, which included re-energizing NSR Bus 243 and Bus 244 from SR Bus 241 and Bus 242, respectively. During the recovery, the crew experienced numerous problems when attempting to start equipment from 480Vac motor control centers (MCCs) that were previously powered from the Unit 2 SATs since the thermal overload protective devices had tripped as a result of the event and operators did not have specific control room indications of these conditions. The thermal overload devices were subsequently reset to restore affected equipment.

Operators performed a reactor cooldown with the primary system operating in the natural circulation mode, utilizing the 2B AF pump and S/G PORVs to remove decay heat in accordance with licensee procedures. Unit 2 subsequently entered Mode 5, Cold Shutdown, on January 31, at 2:28 a.m.

The licensee remained in the NOUE until repairs were completed, the condition of the Unit 2 SATs was evaluated, and offsite power through the Unit 2 SATs to Bus 241 and Bus 242 was restored on January 31.

Unresolved Item: Inadequate Undervoltage Protection

Introduction: The inspectors identified an unresolved item (URI) pending a determination of whether the undervoltage protection design vulnerability revealed by the loss of the single phase event was within the station's current licensing basis (CLB).

Description: TS 3.3.5, "Loss of Power (LOP) DG Start Instrumentation," required that in Modes 1-4 two channels per bus of the loss of voltage (undervoltage) function and two channels per bus of the degraded voltage function shall be operable. In addition, Technical Specification Surveillance Requirement (TSSR) 3.3.5.2 stated that the acceptable channel calibration values for the undervoltage setpoint was greater than 2730Vac, with a time delay of less than or equal to 1.9 seconds; and for the degraded voltage setpoint, the value was greater than 3930Vac with a time delay of 310 plus or minus 30 seconds. Upon actuation of the undervoltage or degraded voltage function, the DGs were designed to start and provide power to all ESF loads.

However, because the ESF undervoltage and degraded voltage protection schemes were comprised of two contacts in series that monitored differential voltages between the A-B and B-C phases, upon the loss of only the "A" or "C" phase, only one protective relay is actuated and therefore does not satisfy the coincidence logic necessary to initiate an undervoltage or degraded voltage protection signal.

The licensee concluded that this event was not within the facility's CLB and that because the NRC had reviewed and approved the design, that the undervoltage protection design vulnerability did not impact operability and that the requirements of TS 3.3.5 were met.

At the end of this inspection, a detailed NRC review of the CLB was in progress. This URI will remain open pending the completion of this review and a determination of whether the undervoltage and degraded voltage protection design vulnerability was within the station's CLB. **(URI 05000454/2012008-001, 05000455/2012008-001, Inadequate Undervoltage Protection)**

.2 Review the Licensee's Post-Trip Data and Independently Review Plant Data and Records (Charter Item 2)

a. Inspection Scope

The inspectors independently reviewed the licensee's post-trip data and interviewed operators and engineering personnel to determine the cause of the Unit 2 reactor trip. Additionally, the inspectors performed plant walkdowns, including the switchyard, and determined whether the licensee’s assessment and planned corrective actions were adequate.

b. Findings

No findings were identified.

The inspectors determined that the loss of the incoming 345kV “C” phase to the Unit 2 SATs was caused by an open “C” phase conductor. The conductor opened when an insulator stack that provided vertical support to the “C” phase conductor failed.

On January 31, 2012, the licensee shipped the broken insulator stack to an offsite facility for a detailed failure analysis. The licensee planned to include the results of this failure analysis in their root cause review. At the end of this inspection, the results of the analysis were not available.

As part of the licensee’s immediate corrective actions, the failed insulator was replaced and the SATs were assessed for damage. In addition, the licensee implemented a number of compensatory actions to raise awareness of the design vulnerability and to provide additional annunciator response instructions for the control room operators. These compensatory actions included the following:

- All active licensed operators were required to complete a “read and sign” information package during the first shift on duty in the main control room;
- The shiftly/daily surveillances were revised to include a check that the voltage selector switch was placed in the C-A position following rounds checks of bus voltage; and
- A designated operator was assigned to Unit 1 and Unit 2 to take the actions necessary to mitigate a similar event within 30 seconds.

.3 Operator Response Assessment (Charter Item 3)

a. Inspection Scope

To assess operator response to the event, the inspectors reviewed control room logs, plant parameter recordings, plant procedures, corrective actions documents, maintenance WOs, and maintenance work request history. The inspectors also conducted interviews with the operators who responded to the event.

The inspectors independently assessed Operations crew procedure usage and their ability to troubleshoot and take appropriate action during the event. In response to the event, the crew entered the following Emergency Operating Procedures (EOPs) and Abnormal Operating Procedures (AOPs):

- 2BEP-0, “Reactor Trip or Safety Injection Unit 2,” Revision 202 WOG [Westinghouse Owners Group] 2;
- 2BEP ES-0.1, “Reactor Trip Recovery Unit 2,” Revision 203 WOG 2;
- 2BEP ES-0.2, “Natural Circulation Cooldown Unit 2,” Revision 200 WOG 2; and
- 2BOA Electrical-3, “Loss of Offsite Power to Unit 2,” Revision 105.

b. Findings

No findings were identified.

Operators properly responded to the event and took the necessary actions when faced with an abnormal reactor trip in which all safety-related motor-driven pumps were inoperable and unavailable for about 8 minutes. This event resulted in a loss of RCP seal cooling with a single train of AF operating and decay heat being removed through the S/G PORVs.

Following the reactor trip, operators performed the first four steps of 2BEP-0, "Reactor Trip or Safety Injection Unit 2", Revision 202, WOG 2, and correctly determined that an electrical problem existed on Unit 2. Operators diagnosed that a problem existed with the Unit 2 SATs and took the appropriate actions to open the associated feeder breakers to ESF Bus 241 and Bus 242. This action caused an automatic start of the 2A and 2B DGs and the ESF loads powered from Bus 241 and Bus 242 to automatically sequence onto their respective DGs. This action also re-established cooling to the RCP seals and restored the safety-related equipment necessary to maintain the plant in a safe shutdown condition.

The inspectors reviewed the EOPs and identified that the existing procedures were not adequate to address this specific event. In particular, Step 3 of 2BEP-0 directed operators to perform the following actions:

- *VERIFY power to the 4kV ESF buses:*
    - a. *ESF buses energized – AT LEAST ONE ENERGIZED*
        - o *Bus 241*
        - o *Bus 242*

The basis of this step, described in procedure BD-EP-0, "Basis Document for Reactor Trip or Safety Injection Procedure," Revision 200, was as follows:

AC [Alternating Current] *power must be verified from either offsite sources or the diesel generators to ensure adequate power sources to operate the safeguards* [ESF] *equipment. At least one train of safeguards equipment is required to deal with emergency conditions. If at least one train is not available, the operator should try to quickly restore one train, e.g., start a diesel generator and load it on the 4kV ESF bus. If at least one train cannot be restored quickly, the operator should transfer to CA-0.0, Loss of All AC Power.*

The crew initially marked off this step as being met satisfactorily based upon main control room indications and past training. The crew verified that ESF Bus 241 and Bus 242 main control room 'bus alive' lights were lit. Since the 4kV voltage selector switch had been selected to the A-B phase voltage position (for both buses), nominal 4kV was indicated in the control room since the A and B phases were not directly affected by the event. Additionally, 4kV bus undervoltage or degraded voltage alarms were not locked in due to the alarming circuitry requiring a two-out-of-two coincidence logic. Therefore, Operations and Training department expectations for how 2BEP-0, Step 3 was to be performed were not adequate for this event. The inspectors discussed this vulnerability with licensee management and staff. However, the inspectors did not identify any operator performance issues since operators effectively utilized their knowledge of plant operations to address the event in a timely manner.

.4 Review the Licensee's Root Cause Evaluation Plan and Schedule (Charter Item 4)

a. Inspection Scope

The inspectors reviewed the licensee's root cause evaluation plan, schedule for completion, and the root cause team's technical structure and membership to determine whether the root cause evaluation plan was of sufficient breadth and depth and whether the time allotted to perform the root cause evaluation was commensurate with the safety significance of the issue.

b. Findings

No findings were identified.

The inspectors observed that the root cause team was from a diverse technical background. Representatives from Operations, Design Engineering, Programs Engineering, Corporate Engineering, and Training were included on the team. Individuals from Commonwealth Edison (ComEd) were also included on the team. The inspectors reviewed the licensee's root cause timeline and concluded that it was scheduled to be completed in accordance with licensee procedures and within a timeframe commensurate with the safety significance of the issues.

The root cause investigation plan was similarly determined to be of adequate depth and breadth and that the time allotted to perform the investigation was appropriate.

.5 Review the Circumstance Surrounding Equipment Problems and Licensee Performance in Addressing These Issues (Charter Item 5)

a. Inspection Scope

The inspectors evaluated the circumstances surrounding and licensee performance in addressing the following equipment problems and issues associated with the January 30, 2012 event:

- Unit 2 RCP Undervoltage Relay Actuation;
- Switchyard C-Phase Disconnect (Bus 13) Failure;
- Unit 2 SAT Damage Assessment and Operability Determination;
- Unit 2 Secondary Side Water Hammer Impact to Equipment Functionality and Availability;
- Starting of Safety-Related Equipment when the SATs were De-energized from an Undervoltage Condition;
- 2B SX Pump Failure to Start Prior to De-energizing the SATs;
- Reactor Coolant Filter Leakage and the Impact on Safety-Related Equipment, Including the 2A RHR Pump and Motor;
- Assessment of the Release of Tritiated Steam;
- RCP Seal Assessment Following a Total Loss of Seal Cooling for About 8 Minutes;

- Operability Determination Process Usage; and
- Missed Opportunities to Identify a Design Issue through Operating Experience.

The inspectors reviewed plant data records and interviewed licensee personnel to understand the circumstances surrounding these issues, including licensee assessments. Additionally, the inspectors reviewed applicable documents, such as operating procedures, system diagrams, the Updated Final Safety Analysis Report (UFSAR), TS requirements, outstanding WOs, and IRs. The inspectors walked down all levels of the Unit 2 turbine building and portions of the main steam tunnel to identify any adverse impact that the secondary side water hammer transients could have caused (e.g., broken pipe hangers, lifted relief valves, unexplained sources of visible water or debris on floors and structures). Additionally, the inspectors performed walkdowns of the main control room, the 345kV switchyard, and low voltage connections to both SR and NSR buses.

b. Findings

No findings were identified.

Unit 2 RCP Undervoltage Relay Actuation

The inspectors identified that RCP Bus 258 and Bus 259 that were powered from the Unit 2 SATs detected the loss of “C” phase voltage and transmitted undervoltage signals to the reactor protection system (RPS).

Each 6.9kV RCP bus voltage potential is sensed and reduced through two potential transformers to about 120Vac. Two sets of relays monitor this bus potential and actuate on an RCP bus equivalent voltage level of about 5268Vac. One set of relays is designed to monitor the A-B voltage potential and the other set of relays is designed to monitor the B-C voltage potential. Since the B-C phase voltage potential decreased to approximately 3980Vac, one set of relays actuated. These relays are set up in a parallel fashion such that actuation of either (or both) relay sets initiates a protective action signal. With undervoltage conditions present on RCP Bus 258 and Bus 259, the RPS responded as designed by automatically tripping the reactor based upon satisfying the necessary two-out-of-four RPS coincidence logic.

The inspectors concluded that the RCP undervoltage portion of the RPS operated as designed. No issues were identified.

Switchyard C-Phase Disconnect (Bus 13) Failure

The inspectors evaluated the licensee’s response to the bus failure including corrective actions and extent of condition review. The inspectors did not identify any issues based, in part, on the assignment of designated operators and other station actions.

Unit 2 SAT Damage Assessment and Operability Determination

The licensee evaluated the impact that the event had on the Unit 2 SATs. The license’s evaluation included a review of past and post-event transformer dissolved gas oil results. These results were then used to assess the condition of the Unit 2 SATs.

After reviewing the results of the dissolved gas analyses and after discussing these results with a vendor, the licensee concluded that the Unit 2 SATs were not damaged. The inspectors independently reviewed the oil sample results, the licensee's evaluation of the oil sample results, and compared the results to established acceptance criteria. The inspectors also observed SAT performance prior to re-energizing ESF equipment and after being fully loaded. No issues were identified.

Unit 2 Secondary Side Water Hammer Impact to Equipment Functionality and Availability

The licensee concluded that there were two main areas where secondary side water hammer occurred due to hot water flashing and/or collapsing. These areas included low pressure feedwater heater bypass line 2CB01C and the condensate/condensate booster (CD/CB) pump suction and discharge lines. The licensee performed numerous secondary system walkdowns to identify any damage caused by the water hammer events that occurred following the Unit 2 reactor trip. No significant issues were identified.

The suspected mechanism for the water hammer associated with the low pressure feedwater heater bypass line was the combined effects of a system pressure reduction due to the loss of the CD/CB pumps, and a vacuum draw at the high point in the system. As draining and cooling occurred within this system, flashing and the collapse of vapor pockets caused the vibration and audible water hammer heard by licensee personnel.

The suspected mechanism for the water hammer associated with the CD/CB pump discharge lines was reverse flow through the pump discharge check valves and flow into the main condenser through the recirculation and pump suction lines. After the relatively hot water reached the main condenser, flashing was suspected to have occurred. At the end of the inspection, the licensee planned to determine whether improvements to the sealing capability of the CD/CB pump discharge check valves was necessary.

The inspectors reviewed the licensee's secondary side water hammer evaluations and walkdown results. Licensee personnel who heard the water hammer events following the Unit 2 trip were interviewed to gain additional insights. Additionally, the inspectors performed independent walkdowns of all Unit 2 turbine building levels and the main steam tunnels to independently verify the results of the licensee's walkdown. No issues were identified.

Starting of Safety-Related Equipment when the Unit 2 SATs were De-energized

The inspectors reviewed the plant's electrical response to the manual action to open the Unit 2 SAT feeder breakers and de-energize the Unit 2 SATs. Following these actions, ESF Bus 241 and Bus 242 de-energized and the DGs started to supply power for the remainder of the event. Safe shutdown loads automatically sequenced onto ESF Bus 241 and Bus 242 as designed.

The inspectors noted that the 2B DG was in an available, but inoperable, status prior to the event as a result of maintenance work that had recently been completed. The inspectors performed a field walkdown on the morning of January 31, 2012, and observed slight 2B DG speed and frequency oscillations of about 0.5 hertz (hz). These frequency oscillations, however, did not prevent the 2B DG from performing its safety function during this event. Following the event and after offsite power was restored, maintenance was performed to address the issue and the 2B DG was tested satisfactorily. No issues were identified.

<u>2B SX Pump Failure to Start Prior to De-energizing the SATs</u>

The inspectors reviewed the equipment response following an attempt to start the 2B SX pump following the event. The inspectors did not identify any specific performance deficiencies given the unique aspects of this event and requirements within the EOPs. The inspectors determined that following the failure of the 2B SX pump to start, operators took prompt action to restore SX flow by cross-connecting SX between units in a timely manner. No issues were identified.

<u>Reactor Coolant Filter Leakage and the Impact on Safety-Related Equipment</u>

During the event, the in-service reactor coolant filter became plugged and contributed to the lifting of the letdown line relief valve to the pressurizer relief tank. As a result of the plugged filter, process radiation monitor 2PR06J experienced a pressure spike. This pressure spike resulted in a 2PR06J isolation valve to begin leaking through a mechanical fitting. The leakage resulted in water flowing into the penetration area below, through the joints and around an equipment access floor plug, and into the 2A RHR room below. The 2A RHR pump motor air outlet fins were positioned in such a manner that provided shielding to prevent the water from actually entering the motor. The licensee determined that the 2A RHR pump remained operable throughout this event. The licensee took corrective actions to repair the leaking connection and evaluated the impact of the leakage on other components. No issues were identified.

<u>Assessment of Release of Tritiated Steam</u>

Following the Unit 2 reactor trip, about 184,000 gallons of water containing trace amounts of tritium was released to the atmosphere through the S/G PORVs in the form of steam. This volume was calculated using the assumption that an equal volume of water was released through the S/G PORVs as was used in AF makeup. Auxiliary feedwater flow rate data over the duration of the release was obtained in 1 minute intervals and summed to obtain a total volume of water used.

The licensee had not recently experienced RCS primary to secondary leakage. Therefore, the only radionuclide of significance was tritium because tritium diffuses through the S/G tubing and enters the secondary system. The licensee routinely performed sampling of the secondary system for tritium with the most recent sample collected on January 30, 2012. The tritium concentration in this sample was about 27,500 picocuries/liter (pCi/L) with no measurable gamma isotopes. The makeup source to the AF pumps was clean, non-tritiated water from the condensate storage tanks. The calculated organ dose to the maximally exposed individual as a result of this release was calculated to be 0.00000109 millirem (mrem). The licensee's quarterly limit was 7.5 mrem with an annual limit of 15 mrem. The release during this event was assigned Permit Number 2012047.

Reactor Coolant Pump Seal Assessment Following a Total Loss of Seal Cooling

The inspectors reviewed the licensee's assessment to ensure that the licensee had adequately evaluated the integrity of the Unit 2 RCP seals following the loss of seal cooling for about 8 minutes. The licensee determined that the RCP seal packages were not adversely affected based upon a review of plant data records, discussions with the vendor, and the performance of a calculation that supported the data observed. Specifically, the licensee concluded that the RCP seal outlet temperature remained below the alarm setpoint of 184 degrees Fahrenheit (°F) during and following the loss of seal cooling event. During the reactor cooldown, the RCP seal outlet temperatures lowered as expected. The licensee performed a calculation to determine the time it would take for the RCP internally cooled seal water to deplete assuming a worst case 2.5 gallon per minute (gpm) seal leakoff rate. The 2.5 gpm leakoff rate was used because this value was the highest RCP seal leakoff rate prior to the event. The licensee's calculation determined that it would take about 13 minutes for this cooled water volume to deplete. This timeframe is important because if this condition is reached, hot RCS water will begin entering each RCP seal package area. As the temperature increases, the seals will eventually soften and fail.

The inspectors reviewed the details of the licensee's reviews and determined that the RCP seals had not been significantly damaged due to the loss of RCP seal cooling. The computer points for the RCP seal outlet temperatures were stable and ranged between 150°F and 160°F. During and after the trip, computer data was not available due to the computer servers losing power. However, control room annunciator 2-7-D3 was set to alarm at 184°F. The significant events recorder did not register this alarm. In addition, when the computer data was available, the temperatures were lower than the indicated pre-event operating temperatures of 150°F-160°F and were decreasing as expected for a plant cooldown. No issues were identified.

Operability Determination Procedure Usage

Unresolved Item: Operability Determination Procedure Implementation Concerns

Introduction: The inspectors identified an URI related to the implementation of operability determination procedure OP-AA-108-115, "Operability Determinations (CM-1)," Revision 11. Specifically, the inspectors questioned whether OP-AA-108-115 was properly implemented since an operability determination was not performed upon discovery of the design vulnerability that was the subject of this inspection.

Description: Following a review of the January 30, 2012 event and the undervoltage protection system, the licensee concluded that because the undervoltage protection system functioned as designed, and because the NRC had reviewed and approved the design, the requirements of TS 3.3.5 were met and the identified design vulnerability did not impact operability.

The inspectors were concerned with this conclusion since it appeared that the current design would not adequately mitigate a loss of "A" or "C" phase event in the absence of operator action, which appeared to not satisfy the intent of the undervoltage and degraded voltage protection systems to ensure that ESF Bus 241 and Bus 242 were powered from either offsite power or onsite power using the DGs.

Subsequently, the licensee performed an operability determination using OP-AA-108-115, “Operability Determinations (CM-1),” Revision 11. During a review of the operability determination, the inspector’s identified issues with OP-AA-108-115.

Specifically, Inspection Manual Chapter (IMC) Part 9900, “Operability Determinations and Functionality Assessments for Resolution of Degraded or Nonconforming Conditions Adverse to Quality or Safety,” stated the following:

- *Circumstance Warranting Operability Determinations.*

Licensees should enter the operability determination process on discovering any of the following circumstance when the operability of any systems, structures, and components described in the TS is called into question:

a. *Degraded conditions;*
b. *Nonconforming conditions; and*
c. *Discovery of an unanalyzed condition.*

However, the licensee stated that OP-AA-108-115 did not require that an operability determination be performed upon the discovery of an unanalyzed condition, and since the non-conforming condition was not within the scope of structures, systems, and components (SSCs) considered in the operability determination process, an operability determination was not required. This decision was based largely on the licensee’s position that the event was outside of their CLB.

At the end of this inspection, a detailed NRC review of the CLB was in progress. This URI will remain open pending the completion of this review and a more detailed review of the licensee’s processes and discussions with NRC experts to determine whether OP-AA-108-115, “Operability Determinations (CM-1),” Revision 11 was appropriately implemented. **(URI 05000454/2012008-02, 05000455/2012008-02, Operability Determination Procedure Implementation Concerns)**

In addition, the inspectors identified that the operability determination process did not establish a time limit for revising an approved operability determination after pertinent information within the evaluation had changed or new information became available that could adversely affect the outcome. The licensee entered this issue into their corrective action program as Issue Report (IR) 1325902, “Gaps in Guidance of Op [Operability] Determination Procedure.”

<u>Operating Experience Review</u>

<u>Unresolved Item: Potential Missed Opportunities to Identify a Latent Undervoltage Design Issue</u>

<u>Introduction</u>: The inspectors identified an URI related to potential missed opportunities to identify the ESF undervoltage protection design vulnerability through the use of operating experience. This issue was considered an URI because at the end of the inspection the scope of operating experience available to the station was unclear.

<u>Description</u>: During the inspection, the inspectors identified that Licensee Event Report (LER) 05000334/07-002, “Undetected Loss of 138kV “A” Phase to System Station Service Transformer Leads to Condition Prohibited by Plant Technical Specifications,”

discussed an event at Beaver Valley Nuclear Power Plant that was similar to the Byron event when on November 27, 2007, a site construction supervisor discovered that the "A" phase conductor on a Beaver Valley Power Station three-phase 138kV power line had broken off in the switchyard. This break occurred between the offsite feeder breaker and the "A" train system service transformer at the line side high voltage terminal to the "A" phase revenue metering device. Upon discovery, the Beaver Valley licensee declared the "A" train offsite power circuit inoperable and entered the applicable TS action statement. Since nominal electrical power to the safety-related buses was supplied from the main generator, an actual undervoltage condition or demand for undervoltage protection did not occur.

The inspectors discussed this operating experience with licensee staff and management. The inspectors determined that the licensee had previously evaluated this operating experience and had concluded at that time that no actions or additional review was needed. The inspectors concluded that it was reasonable for this review to have considered the effects of losing the "A" (or "B", or "C") phase supplying the Unit SATs from their high voltage ring bus.

In addition, numerous insulator failures had occurred in both the nuclear and non-nuclear industry. In particular, Technical Bulletin 05-018, "HK Porter MK40A Disconnect Insulators," discussed the identification of a series of cracked Ohio Brass insulators on 345kV disconnects. This type of insulator was used in the Byron switchyard.

At the end of this inspection, additional operating experience was being reviewed to determine the complete scope of prior opportunities to identify the design vulnerability. This URI will remain open pending the completion of that review and a determination of whether the failure to identify operating experience for the identified design vulnerability was indicative of recent performance. **(URI 05000454/2012008-03, 05000455/2012008-03, Missed Opportunities to Identify a Latent Undervoltage Protection Design Issue)**

4OA6 Management Meetings

Exit Meeting Summary

On February 13, 2012, the inspectors presented the inspection results to Mr. T. Tulon, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that proprietary information reviewed as part of this inspection was returned to the licensee.

ATTACHMENTS:
1. SUPPLEMENTAL INFORMATION
2. SPECIAL INSPECTION CHARTER
3. EVENT TIMELINE

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

T. Tulon, Site Vice President
B. Youman, Plant Manager
D. Coltman, Operations Manager
J. Feimster, Design Engineering Manager
D. Damptz, Acting Maintenance Director
S. Swanson, Nuclear Oversight Manager
R. Gayheart, Training Director
D. Gudger, Regulatory Assurance Manager
R. Cameron, Licensed Operator Requalification Lead

Nuclear Regulatory Commission

S. West, Director, Division of Reactor Projects, Region III
E. Duncan, Chief, Reactor Projects Branch 3, Region III

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000454/2012008-01; 05000455/2012008-01	URI	Inadequate Undervoltage Protection
05000454/2012008-02; 05000455/2012008-02	URI	Operability Determination Procedure Implementation Concerns
05000454/2012008-03; 05000455/2012008-03	URI	Missed Opportunities to Identify a Latent Undervoltage Protection Design Issue

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspector reviewed the documents in their entirety, but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

- IR 1319612; B2F26 Frequency Oscillation Observed on 2B DG; January 29, 2012
- IR 1319652; B2F26 2B DG Output Power Swings 500 KW; January 30, 2012
- IR 1319655; B2F26 Investigate Oil Drainage from 3L Cylinder Inspection Cover; January 30, 2012
- IR 1319894; B2F26 2TO07P High Pressure Seal Oil B/U PP Wouldn't Start; January 30, 2012
- IR 1319908; B2F26 U2 Reactor Trip Due to Electrical Fault and Unusual Event; January 30, 2012
- IR 1319916; Minor Leak on Compression Fitting 2MS237D; January 30, 2012
- IR 1319932; Minor Leak on 2MS95AB Sample Cooler Canister; January 30, 2012
- IR 1319937; B2F26 2VP03CV Did Not Start; January 30, 2012
- IR 1319968; B2F26 2PR-011 Containment Atmosphere PRM Tripped – Needs Restart; January 30, 2012
- IR 1319989; B2F26 2PR21J; January 30, 2012
- IR 1310006; B2F26 U2 Trip SAT C-Phase Found Open; January 30, 2012
- IR 1320073; B2F26 2A GS Cond Fan Leakage; January 30, 2012
- IR 1320079; B2F26 Leakage at 2B GS Fan Casing; January 30, 2012
- IR 1320095; Emergent Security Support Request; January 30, 2012
- IR 1320102; Slight Packing Leak at 2HD046B; January 30, 2012
- IR 1320111; B2F26 2B FW PP Emergent Oil PP Appears to Have Failed; January 30, 2012
- IR 1320119; 2MS004F Has Minor Packing Leak; January 30, 2012
- IR 1320123; Contingency WO for Condenser in-Leakage Testing; January 30, 2012
- IR 1320140; B2F26 CC Low Flow to 2A and 2D RCP Thermal Barrier HXs; January 30, 2012
- IR 1320144; B2F26 2MS004LL Does Not Appear to be Responding Properly; January 30, 2012
- IR 1320145; B2F26 2PR 01J Cannot be Started Following the Loss of Units SATs; January 30, 20112
- IR 1320154; B2F26 Div 22 HVAC Tripped and Will Not Restart; January 30, 2012
- IR 1320157; B2F26 Div 21 HVAC Tripped and Will Not Restart; January 30, 2012
- IR 1320158; B2F26 2LC-ES094 Controller Cover is Open and Press Gage Lens Off; January 30, 2012
- IR 1320160; B2F26 U2 Main Turbine Turning Gear Motor Won't Start; January 30, 2012
- IR 1320161; B2F26 2PR030J Cannot be Started After Loss of Unit 2 SATs; January 30, 2012
- IR 1320179; B2F26 U2 RX Trip Caused RCS Contaminated Water Leaks; January 30, 2012
- IR 1230192; B2F26 Water Intrusion Leaking Through Area 7 on to 2RH01PA; January 30, 2012
- IR 1320198; B2F26 2VT05CB Tripped; January 30, 2012
- IR 1320203; B2F26 Unit 2 Turbine Turning Gear Motor Will Not Start; January 30, 2012
- IR 1320204; Oil Filter on 2B TDFW PP Needs Replacing; January 30, 2012
- IR 1320205; B2F26 U2 kV Output Breaker GCB 10-11 Failed to Close; January 30, 2012
- IR 1320206; B2F26 2A Air Side Seal Oil Filter 2TO04S-FA High DP; January 30, 2012
- IR 1320221; B2F26 2CB025 Air Leak; January 30, 2012
- IR 1320225; B2F26 U2 Hotwell Loss of Integrity; January 30, 2012
- IR 1320227; B2F256 Emergent Dose Request for U2 Walk Down; January 30, 2012

- IR 1320241; B2F26 U2 MG Output Disconnect Linkage Requires Adjustment; January 30, 2012
- IR 1320244; Emergent Dose – B2F26; January 30, 2012
- IR 1320252; B2F26 U1 NDCT Overflow; January 30, 2012
- IR 1320266; B2F26 2WF04PB Failed to Start on Sump Level; January 30, 2012
- IR 1320267; B2F26 Suspect Severe Bearing Damage to PP & Turbine Bearings; January 30, 2012
- IR 1320324; B2F26 2CV225 Dry Packing Leak – B2F26; January 30, 2012
- IR 1320326; B2F26 2CV225 Dry Pipe Cap Leak – B2F26; January 30, 2012
- IR 1320327; B2F26 Water Drips Now, Air In-leakage at Power; January 30, 2012
- IR 1320328; B2F26 2RC8042C Dry Packing Leak - B2F26; January 30, 2012
- IR 1320330; B2F26 2RC8042D Dry Packing Leak - B2F26; January 30, 2012
- IR 1320352; B2F26 SAT 242-1 Oil Sample Results - Increased Combustible Gases; January 31, 2012
- IR 1320353; B2F26 SAT 242-2 Oil Sample Results - Increased Combustible Gases; January 31, 2012
- IR 1320354; B2F26 Need Oil Samples from 2C and 2B FW PPs; January 31, 2012
- IR 1320355; B2F26 Emergent Dose Approval Required for 2WF04PB; January 31, 2012
- IR 1320359; B2F26 2B Fuel Oil Pump Inlet Pressure is High Out of Spec; January 31, 2012
- IR 1320361; B2F26 2B AF PP Gearbox Oil PP Trips Thermal Overloads; January 31, 2012
- IR 1320373; B2F26 LL – MPA Overfeed Following B2F26 Shutdown; January 30, 2012
- IR 1320382; B2F26 Thermal Overloads for 2A AF PP Aux Lube Oil PP Tripped; January 31, 2012
- IR 1320392; B2F26 2A Seal Injection Filter - 2CV01FA; January 30, 2012
- IR 1320394; B2F26 2CV01FB-2B Seal Injection Filter; January 30, 2012
- IR 1320395; B2F26 U-2 RC Filter 2CV03F; January 30, 2012
- IR 1320406; B2F26 ¾"Service Air Drain Valve Leaking By Post U2 Trip; January 30, 2012
- IR 1320419; B2F26 RF Leak Causing Water Intrusion to Area 7 & 2A RH Pump Room; January 30, 2012
- IR 1320511; B2F26 Review of U2 RCP Seal Operating Conditions Needed; January 30, 2012
- IR 1320516; 2EIR-DC035 Bus 212 Ground Recorder has Flashing Message Box; January 31, 2012
- IR 1320525; B2F26 Ops and MM Support of BOP FW-15; January 31, 2012
- IR 1320526; B2F26 SAT 242-1 Mod Open Light Socket Broke in MCR; January 31, 2012
- IR 1320536; U1 Condensate Tritium; January 30, 2012
- IIR 1320571; B2F26 Byron Fire Department Response to UE; January 30, 2012
- IR 1320581; 2A MSIV Low Pressure Alarm in Prior to Reaching Setpoint; January 31, 2012
- IR 1320605; B2F26 DG Lube Oil Purifier Trouble Alarm; Event Date March 16, 1987 – Discovery Date January 26, 2012
- IR 1320610; B2F26 2A Seal Injection Filter Has HI DP; January 31, 2012
- IR 1320625; B2F26 Additional Unit 2 Trip Issues Requiring Investigation; January 30, 2012
- IR 1320662; B2F26 Contingency Needs Created for U2 RD Current Balancing; January 31, 2012
- IR 1320683; B2F26 U1 OLR Eval Not Performed Prior to Making Equipment Unavailable; January 31, 2012
- IR 1320687; B2F26 U1/U2 OLR Eval Not Performed Following Failure of BT 10-11; January 30, 2012
- IR 1320769; B2F26 Diaphragm Leak on 2CV8421; January 30, 2012
- IR 1320899; B2F26 EOC Walkdown – 2RE9157 Solenoid Valve Wet; January 31, 2012
- IR 1320901; B2F26 EOC Walkdown – 2RE9157 Open Limit Switch is Wet; January 31, 2012
- IR 1320903; B2F26 EOC Walkdown – 2RE9157 Closed Limit Switch is Wet; January 31, 2012

- IR 1320906; B2F26 EOC Walkdown – 2RE9159B Solenoid Valve is Wet; January 31, 2012
- IR 1320907; B2F26 EOC Walkdown – 2RE9159B Open Limit Switch is Wet; January 31, 2012
- IR 1320908; B2F26 EOC Walkdown – 2RE9159B Closed Limit Switch is Wet; January 31, 2012
- IR 1320910; B2F26 EOC Walkdown – 2RE9159B 2nd Solenoid Valve is Wet; January 31, 2012
- IR 1320911; B2F26 EOC Walkdown – 2RE9160B Solenoid Valve is Wet; January 31, 2012
- IR 1320913; B2F26 EOC Walkdown – 2RE9160B Open Limit Switch is Wet; January 31, 2012
- IR 1320915; B2F26 EOC Walkdown – 2RE9160B Closed Limit Switch is Wet; January 31, 2012
- IR 1320916; B2F26 EOC Walkdown – 2RY8028 Solenoid Valve is Wet; January 31, 2012
- IR 1320920; B2F26 EOC Walkdown – 2RY8029 Open Limit Switch is Wet; January 31, 2012
- IR 1320921; B2F26 EOC Walkdown – 2RY8028 Closed Limit Switch is Wet; January 31, 2012
- IR 1320925; B2F26 EOC Walkdown – 2SI8963 Closed Limit Switch (NSR) is Wet; January 31, 2012
- IR 1320927; B2F26 EOC Walkdown – 2SI8964 Solenoid Valve is Wet; January 31, 2012
- IR 1320929; B2F26 EOC Walkdown – 2SI8964 Open Limit Switch is Wet; January 31, 2012
- IR 1320929; B2F26 EOC Walkdown – 2SI8964 Closed Limit Switch is Wet; January 31, 2012
- IR 1320930; BwF26 EOC Walkdown – 2SI8964 Closed Limit Switch (NSR) is Wet; January 31, 2012
- IR 1320932; B2F26 EOC Walkdown – Junction Box 2JB509A is Wet; January 31, 2012
- IR 1320933; B2F26 EOC Walkdown – Junction Box 2JB307A is Wet; January 31, 2012
- IR 1320934; B2F26 EOC Walkdown – Junction Box (Pull Box) 2JB1784A is Wet; January 31, 2012
- IR 1320938; B2F26 MCC 234V Rattling Noise; January 31, 2012
- IR 1320939; B2F26 LL – IST Cold Shutdown Testing; January 31, 2012
- IR 1320941; B2F26 U2 Loss of Offsite Power Annunciator Lit After Power Restart; January 31, 2012
- IR 1321014; B2F26 Replace Ceramic Insulators on U1 345KV Line from MPTS; January 31, 20121
- IR 1321015; B2F26 Replace Ceramic Insulators on 345KV Line from U1 MPTS; January 31, 2012
- IR 1321016; B2F26 Replace Ceramic Insulators on 345KV Line to U2 SATs; January 31, 2012
- IR 1321018; B2F26 Replace Ceramic Insulators on 345KV Line to U1 SATs; January 31, 2012
- IR 1321033; B2F26 Inspect Transmission Lines From SAT 142 to Switch Yard Disconnect; January 31, 2012
- IR 1321035; B2F26 Inspect U1 MPT Transmission Line Up to Switch Year Disconnect; January 31, 2012
- IR 1321037; B2F26 Inspect SAT 242 Transmission Line Up to Switchyard Disconnect; January 31, 2012
- IR 1321039; B2F26 Inspect U2 MPT Transmission Line Up to Switchyard Disconnect; January 31, 2012
- IR 1321055; Blowdown Valve Failed Closed; February 1, 2012
- IR 1321113; 2PR06J Valve Leaking Actively; February 2, 2012
- IR 1321114; TR Pond Sump Pumps 1 & 2 Will Not Run; February 1, 2012
- IR 1321129; LL-B2F26 Verification of Ground Removal Good Practice; January 31, 2012
- IR 1321228; MMD Resources Unable to Support 0A Chiller Window; January 31, 2012
- IR 1321246; Missing Blades on Cooling Motor; February 1, 2012
- IR 1321264; RP Training Deferred Due to B2F26; January 30, 2012
- IR 1321268; Water Leaking from Bottom of Condenser; February 1, 2012
- IR 1321301; U2 RX Trip IR to Include in Operator Training; January 30, 2012
- IR 1321360; 2CV8117 Letdown Orific Outlet HDR RLF VLV Lifted," February 1, 2012

- IR 1322212; Potential Design Vulnerability in SY Single Open Phase; February 3, 2012
- IR 1325902; Gaps in Guidance of OP Determination Procedure
- B2F26 Loss of C Phase Inspection 2012 Status Report; February 3, 2012
- B2F26 OCC Turnover 1730; January 30, 2012
- B2F26 Execution Scope Log
- MD 8.3; Unit 2 Deterministic Criteria Evaluation; January 30, 2012
- PWR B Spar Model for Byron Units 1 & 2; IE-LOOPSC
- Byron U2 Abnormal Gaseous Release; January 30, 2012 – January 31, 2012
- Shift Manager Daily Events; January 12, 2012
- Gaseous Release Permit Report; Permit #2012047; 15 Abnormal Batch Release Unit 2; Permit Start January 2013 and Permit End January 2, 2013; January 31, 2012
- Byron MRC Agenda; Updated on November 29, 2011
- 2BCA-0.1; Loss of All AC Power Recovery Without SI Required - Unit 2; Revision 200 WOG 2
- PORC Checklist; Post Transient Review; February 7, 2012
- LS-AA-108-108; Unit Restart, Start Up PORC for B2F26, Attachments 109, Department Checklists; Revision 12; February 2, 2012
- LS-AA-1150; NRC Form 351 Event Notification Worksheet; February 6, 2012
- OP-AA-102-104; Evaluation of the Effect of a Single Open-Phase Condition on 480V ESF Equipment – Log #12-007; February 6, 2012
- OP-AA-108-108; Unit Restart Review; Revision 12
- OP-AA-108-114; Post Transient Review; 2C Steam Generator Experienced a P-14 HI-2 SG Level; February 6, 2012
- MA-AA-716-004; Unit 2 MCCs Troubleshooting Log; Revision 10
- NOS Byron Site Status Report; January 10, 2012
- PNO; Byron U2 Restarts After Loss of Offsite Power and Declaring a Notice of Unusual Event; February 7, 2012
- LER 05000454/1996-007-00; Loss of Offsite Power Due to a Failure of an Insulator on Phase B of the Unit 1 Station Auxiliary Transformer from Water Intrusion; May 23, 1996
- LER 05000333/2005-006-00 and 05000220/2005-006-00; Inoperable 115 kV Line in Excess of TS Allowed OOS Time; December 19, 2005
- LER 05000220/2005-004-00; Operation Prohibited by TS Due to Unrevealed Inoperability of One Offsite Power Source; December 19, 2005
- LER 05000334/2007-002-00; Undetected Loss of 138 kV ‘A’ Phase to System Station Service Transformer Leads to Condition Prohibited by Plant TS; November 27, 2007
- LER 05000455/2008-001-00; Unit 2 EDG and Auxiliary Feedwater Pump Automatic Start Resulting from a Loss of Offsite Power Due to a Failed Insulator Causing a Differential Phase Overcurrent; March 25, 2008
- Dwg 6E-1-4017C; Relaying & Metering 6900V Swgr Bus 258
- Dwg 6E-1-4030AP21; 6.9kV Swgr Bus 158 Undervoltage and Underfrequency Relays
- Dwg 6E-2-4008A; 480V Auxiliary Building ESF MCC 231X1 (2AP21E) Part 1
- Dwg 6E-2-4008B; 480V Auxiliary Building ESF MCC 231X1 (2AP21E-A) Part 2
- Dwg 6E-2-4008E; 480V Auxiliary Building ESF MCC 231X2 (2AP25E & 231X2A (2AP25E-A)
- Dwg 6E-2-4008G; 480V Auxiliary Building ESF MCC 231X2B (2AP25E-B)
- Dwg 6E-2-4008Q; 480V Auxiliary Building ESF MCC 231X3 (2AP22E)
- Dwg 6E-2-4008U; 480V Auxiliary Building ESF MCC 231X5 (2AP30E)
- Dwg 6E-2-4008AG; ESW Cooling Water ESF MCC 231Z1 (2AP93E)
- Dwg 6E-2-4008BC; 480V Auxiliary Building ESF MCC 233X4 (2AP44E)
- Dwg 6E-2-4008BE; 480V Auxiliary Building ESF MCC 233V2 (2AP46E)
- Dwg 6E-2-4008BY; 480V Turbine Building ESF MCC 231Y1 (2AP51E)
- Dwg 6E-2-4008CA; 480V Turbine Building ESF MCC 231V3 (2AP53E)
- Dwg 6E-2-4008CC; 480V Turbine Building ESF MCC 233V4 (2AP55E)

- Dwg 6E-2-4008CU; 480V Turbine Building ESF MCC 231V5 (2AP57E)
- Dwg 6E-2-4008CW; 480V Turbine Building ESF MCC 231Z2 (2AP59F)
- Dwg 6E-2-4008DQ; 480V Auxiliary Building ESF MCC 233X3(2AP42E)
- Dwg 6E-2-4008AU; 480V Auxiliary Building ESF MCC 233X1 (2AP38E)
- Dwg 6E-2-4008BA; 480V Auxiliary Building ESF MCC 233X3 (2AP42E)
- Dwg 6E-2-4008BJ; 480V Auxiliary Building ESF MCC 234V1 (2AP39E)
- Dwg 6E-2-4008BL; 480V Auxiliary Building ESF MCC 234V2 (2AP41E)
- Dwg 6E-2-4008BN; 480V Auxiliary Building ESF MCC 233V3 (2AP43E)
- Dwg 6E-2-4008BQ; 480V Auxiliary Building ESF MCC 234V4 (2AP45E)
- Dwg 6E-2-4008BS; 480V Auxiliary Building ESF MCC 234X5 (2AP47E)
- Dwg 6E-2-4008CL; 480V Turbine Building ESF MCC 234Y2 (2AP54E)
- Dwg 6E-2-4008CN; 480V Turbine Building ESF MCC 234Y3 (2AP56E)
- Dwg 6E-2-4008DG; 480V Turbine Building ESF MCC 234V6 (2AP58E)
- Dwg 6E-2-4008DJ; 480V Turbine Building ESF MCC 234Z2 (2AP60E)
- Dwg 6E-2-4008J; 480V Auxiliary Building ESF MCC 232X1 (2AP23E)
- Dwg 6E-2-4008L; 480V Auxiliary Building ESF MCC 232X2 (2AP27E & A)
- Dwg 6E-2-4008Y; 480V Auxiliary Building ESF MCC 232X3 (2AP24E)
- Dwg 6E-2-4008AA; 480V Auxiliary Building ESF MCC 232X4 (2AP28E) & MCC 232X4A (2AP28EA)
- Dwg 6E-2-4008AC; 480V Auxiliary Building ESF MCC 232X5 (2AP32E)
- Dwg 6E-2-4008AN; 480V ESW Cooling Tower ESF MCC 232Z1 (2AP92E)
- Dwg 6E-2-4008AQ; 480V ESW Cooling Tower ESF MCC 232Z1A (2AP88E)
- Dwg 6E-2-4008CY; 480V CW Pump House MCC 233U1 (2AP97E)
- Dwg 6E-2-4008DL; 480V CW Pump House MCC 234U1 (2AP96E)
- Dwg 6E-2-4030SX02; Essential Service Water Pump 2B 2SX01PB
- Dwg 6E-2-4030AP35; Bus Tie Breaker ACB #2421 (4.16kV ESF Swgr, Bus 242 to 4.16kV Bus 244)
- Dwg 6E-2-4030AP21; 6.9kV Swgr Bus 258 Undervoltage and Underfrequency Relays
- Dwg 6E-2-4030AP17; 6.9kV Swgr Bus 256 Undervoltage and Underfrequency Relays
- Dwg 6E-2-4030AP13; 6.9kV Swgr Bus 256 Undervoltage and Underfrequency Relays
- Dwg 6E-2-4019A; Relaying & Metering Diagram 480V ESF Swgr Bus 231X & 231Z; Revision K
- Dwg 6E-2-4019B; Relaying & Metering Diagram 480V ESF Swgr Bus 232X & 232Z; Revision K
- Dwg 6E-2-4019C; Relaying & Metering Diagram 480V ESF Swgr Bus 233X & 233Y; Revision K
- Dwg 6E-2-4019D; Relaying & Metering Diagram 480V ESF Swgr Bus 234X & 234Y; Revision K
- Op Eval 12-001, Potential Design Vulnerability in Switchyard Single Open Phase Detection
- BYRSER-08, 8.2.4 Adequacy of Station Electric Distribution System Voltages
- OP-AA-108-115, Operability Determinations (CM-1), Revision 11
- NUREG 0800, Branch Technical Positions (PSB-1, 2, 4, 8,11,15, 17, 18, 21)
- NUREG 0800, Section 8.1 Electric Power
- NUREG 0800, Section 8.2 Offsite Power System
- NUREG 0800, Section 8.3.1 A-C Power Systems (Onsite)
- NUREG 0800, Section 8.3.2 D-C Power Systems (Onsite)
- RCP Seal Package Training Document, RCP-1, Revision 25
- NRC Information Notice 2005-04: Single Failure and Fire Vulnerability of Redundant Electrical Safety Buses
- OP-AA-108-108, Unit Restart Review, Revision 12
- AR 01322414, Fleet Review of Potential Design Vulnerability in Switchyard

- BOP AP-55, Isolating/Restoring the Unit 2 System Auxiliary Transformers 242-1 and 242-2 with the Unit 2 Auxiliary Transformers De-Energized, Revision 11
- Shift Logs from 1/30/2012 – 1/31/2012
- Byron Station Read and Sign for Byron U-2 Trip response
- CC-AA-5001, Attachment 1, SSCS Inspected and Degraded Conditions Identified During Post Transient Walkdown
- Unit 2 SAT Fluid Analysis Report from January 30, 2012
- OP-AA-102-104, Unit 1/2 Standing Order, 12-006, February 3, 2012
- BAR 2-21-C7, Bus 241 Overload or Volt Low, Revision 8
- 2BEP-0, Reactor Trip or Safety Injection, Revision 202 WOG 2
- 2BEP ES-0.1, Reactor Trip Response Unit 2, Revision 203 WOG 2
- 2BEP ES-0.2, Natural Circulation Cooldown Unit 2, Revision 200 WOG 2
- EC Eval #0000387571, B2F26 Review of U2 RCP Seal Loss of Seal Cooling Event, Revision 0
- TS 3.3.5, Loss of Power Diesel Generator Start Instrumentation
- Exelon Energy Delivery Technical Bulletin TB 05-018, dated April 25, 2005

LIST OF ACRONYMS USED

AC	Alternating Current
ADAMS	Agencywide Document Access Management System
AF	Auxiliary Feedwater
AOP	Abnormal Operating Procedure
CC	Component Cooling Water
CD/CB	Condensate/Condensate Booster
CLB	Current Licensing Basis
CV	Centrifugal Charging
CFR	Code of Federal Regulations
DC	Direct Current
DG	Emergency Diesel Generator
DRP	Division of Reactor Projects
DRS	Division of Reactor Safety
EDG	Emergency Diesel Generator
EN	Event Notification
EOP	Emergency Operating Procedure
ESF	Engineered Safety Features
°F	Degrees Fahrenheit
gpm	Gallons per Minute
HVAC	Heating, Ventilation, and Air Conditioning
hz	Hertz
IEMA	Illinois Emergency Management Agency
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
IR	Issue Report
kV	Kilovolt
LER	Licensee Event Report
LOP	Loss of Power
MCC	Motor Control Center
mrem	miilirem
MSIV	Main Steam Isolation Valve
NARS	Nuclear Accident Reporting System
NOUE	Notice of Unusual Event
NRC	U.S. Nuclear Regulatory Commission
NSR	Nonsafety-Related
OpEval	Operability Evaluation
PA	Protected Area
PARS	Publicly Available Records System
PORV	Power-Operated Relief Valve
pCi/L	Picocuries Per Liter
RCP	Reactor Coolant Pump
RHR	Residual Heat Removal
RPS	Reactor Protection System
SAT	Station Auxiliary Transformer
S/G	Steam Generator
SR	Safety-Related
SSC	Structure, System and Component
SX	Essential Service Water

TS	Technical Specification
TSSR	Technical Specification Surveillance Requirement
UAT	Unit Auxiliary Transformer
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
Vac	Volts Alternating Current
WO	Work Order
WOG	Westinghouse Owners Group

BYRON SPECIAL INSPECTION CHARTER

This Special Inspection Team is chartered to assess the facts and circumstances surrounding the Byron Unit 2 reactor trip and subsequent equipment issues on January 30, 2012.
The Special Inspection will be conducted in accordance with Inspection Procedure 93812, "Special Inspection," and will include, but not be limited to, the items listed below.

1. Establish a historical sequence of events related to the January 30, 2012, Byron Unit 2 reactor trip. Include relevant plant conditions, system line-ups, and operator actions.

2. Review the licensee's post-trip data to determine the root cause of the Unit 2 reactor trip. Independently review plant data and records to confirm the adequacy of the licensee's assessment and planned corrective actions.

3. Assess operator response to the January 30, 2012, event.

4. Review the licensee's root cause evaluation plan and schedule. Evaluate whether the root cause evaluation plan is of sufficient breadth and depth. Confirm that the time allowed to perform the root cause evaluation is commensurate with the safety significance of the issue. Communicate with the licensee that the NRC will inspect the completed root cause evaluation and the associated corrective actions as part of routine inspection activities.

5. Review the circumstances surrounding equipment problems associated with the January 30, 2012, event. Include in this review an assessment of the licensee's performance in addressing these issues. Consider cause determinations; planned corrective actions; prior similar events; the adequacy of past corrective actions, if applicable; the adequacy of the licensee's extent of condition review; and the adequacy of past operability reviews, if applicable. The review should include, but not be limited to the following issues:

   - Unit 2 RCP undervoltage relay actuation;
   - Switchyard C-Phase Disconnect Switch (Bus 13) failure;
   - Unit 2 System Auxiliary Transformers (SATs) damage assessment and operability determination;
   - Unit 2 secondary side water hammer impact to equipment functionality and availability;
   - Starting of safety-related equipment when the SATs were de-energized from an undervoltage condition;
   - 2B Essential Service Water (SX) pump failure to start prior to de-energizing the SATs;
   - Reactor coolant filter leakage and the impact on safety-related equipment, including the 2A Residual Heat Removal pump motor; and
   - The amount and impact of tritium released to the environment as a result of the event.

Additional Inspection Requirements

Determine if there are any lessons learned from this Special Inspection.

Charter Approval

/RA/
Eric Duncan, Chief
Branch 3
Division of Reactor Projects

/RA by Gary L. Shear for/
Steven West, Director
Division of Reactor Projects

Event Timeline
January 30, 2012, Byron Unit 2 Reactor Trip

The timeline developed was created independently by the special inspection team, with estimates based on the best information available at the time of the inspection. Approximated times are preceded with "~" prior to the listed time. During the development of this timeline, all times were referenced to the main control room control room clock, which was considered the official time. The times listed below are based on a 24-hour central standard time (CST) clock (i.e., 1001:33 is 10:01 and 33 seconds a.m., CST).

<u>January 30, 2012</u>

<u>Initial Conditions</u>: Unit 1 and Unit 2 operating at 100 percent power.

~1001:54	An insulator stack supporting the "C" phase conductor for 345kV Bus 13 that supplies power to the Unit 2 SATs breaks, resulting in an open "C" phase conductor.
1001:55	6.9kV NSR RCP Bus 258 and Bus 259 supplied by the Unit 2 SATs are affected by the open "C" phase. Unit 2 RPS senses the RCP bus undervoltage and initiates an automatic reactor trip.
1001:55	Unit 2 ESF Bus 241 and Bus 242 supplied by the Unit 2 SATs are affected by the open "C" phase. However, due to the design of the undervoltage protection logic, a bus undervoltage protection signal is not processed and Bus 241 and Bus 242 remain energized with the A-B phase at nominal 4000 Vac, the A-C phase at about 2400 Vac, and the B-C phase at about 2400 Vac.
1001:56	2A SX pump low discharge pressure annunciator alarm is received due to an overcurrent trip of the running 2A SX pump.
1001:56	2A (motor-driven) AF pump and 2B (diesel-driven) AF pump receive auto-start signals as designed due to the RCP bus undervoltage condition. The 2B AF pump starts and operates as designed. The 2A AF pump is unable to start and run due to the undervoltage condition.
1001:59	Overcurrent trip of the running 2A CC pump. The 2B CC pump is unable to start and run due to the undervoltage condition. A loss of cooling to all four RCP thermal barrier heat exchangers occurs.
~ 1002	Unit 2 operators enter procedure 2BEP-0, "Reactor Trip or Safety Injection."
1002:00	Overcurrent trip of the running 2B CV pump.
1002:01-02	RCP seal injection flow annunciator alarms received for the 2A, 2B, 2C, and 2D RCPs indicating a loss of RCP seal injection to all four RCPs.
1002:02-03	Overcurrent trip of the running 2A, 2B, and 2D CD/CB pumps.
1002:05	Overcurrent trip of the running auxiliary building supply fan.

1002:13	Overcurrent trip of the running auxiliary building exhaust fan.
1002:32	Main generator reverse power trip occurs and generator output breakers 10-11 and 11-12 trip open.
1002:33	Nonsafety-related Bus 243 and Bus 244 supplied by the Unit 2 UATs trip upon the main generator reverse power trip. Nonsafety-related loads including circulating water pumps, feedwater pumps, a reactor cavity fan, station air compressors, control rod drive mechanism booster and exhaust fans, and heater drain pumps de-energize. 6.9kV Bus 256 and Bus 257 automatically transfer from the Unit 2 UATs to the (degraded) SATs as designed. With phase "C" open, the current flow on the "A" and "B" phases increases.
1002:35	Overcurrent trip of RCP 2C and RCP 2D.
1002:43	ESF Bus 241 low voltage alarm is received in the main control room for about 2 seconds then clears.
1003:13	Overcurrent trip of RCP 2A and RCP 2B.
~1004	Operators attempt to start the 2B SX pump, but the pump fails to start.
1004:54	Operators start the 1A SX pump and open the Unit 1 to Unit 2 cross-connect valves to supply SX from Unit 1 to Unit 2.
~1009-1010	Based upon a field report of smoke from the Unit 2 242-1 and 242-2 SATs, and a suspected electrical issue, operators open the SAT 242-1 and SAT 242-2 feeder breakers to ESF Bus 241 and Bus 242, and NSR Bus 243 and Bus 244.
1009:48	ESF Bus 241 is electrically isolated following the manual operator action. Undervoltage logic is satisfied and an undervoltage signal is processed. The 2A DG starts and restores power to ESF Bus 241 in about 6-8 seconds. Safe shutdown loads begin to automatically sequence onto ESF Bus 241 being powered from the 2A DG.
1010:07	ESF Bus 242 is electrically isolated following the manual operator action. Undervoltage logic is satisfied and an undervoltage signal is processed. The 2B DG starts and restores power to ESF Bus 242 in about 6-8 seconds. Safe shutdowns loads begin to automatically sequence onto ESF Bus 242 being powered from the 2B DG.
1009:56	2A CV pump automatically starts and runs.
1010:15	2B CV pump automatically starts and runs.
1010:16	2A CC pump automatically starts and runs. Seal cooling is restored to the RCP seals.
1018	Byron Station declares a Unit 2 NOUE due to the loss of offsite power to ESF Bus 241 and Bus 242 for greater than 15 minutes.

1023 The licensee requests offsite assistance from the Byron Fire Department based upon the report of smoke from the Unit 2 SATs.

1048 The Byron Fire Department arrives and is available as a resource. No actual fire occurred. The smoke from the Unit 2 SATs was caused by a sudden heat up of the SAT windings due to an electrical current inrush following the insulator failure.

1026 Nonsafety-related Bus 243 is energized from ESF Bus 241, and NSR Bus 244 is energized from ESF Bus 242. Operators begin restoring NSR loads in accordance with licensee procedures.

1039 The licensee notifies the NRC Headquarters Operations Center of the Unit 2 reactor trip, loss of offsite power, and NOUE emergency declaration.

1041 The Unit 2 SAT high side windings are de-energized by the opening of switchyard breakers 7-13 and 12-13 and associated motor-operated disconnects.

1048 The Unit 2 main steam isolation valves (MSIVs) are closed in accordance with licensee procedure due to the loss of main condenser circulating water flow and the Unit 2 shutdown condition.

1100 Operators enter procedure 2BEP ES0.2, “Natural Circulation Cooldown.”

1320 The Operations Field Supervisor completes an investigation of water reportedly spraying onto the 2A RHR pump. The assessment concludes that the water spray does not impact the ability of the pump to start and operate.

2201 Unit 2 enters Mode 4.

<u>January 31, 2012</u>

1233 Operators place Unit 2 in shutdown cooling using the 2B RHR pump.

1428 Unit 2 enters Mode 5

2000 The Byron NOUE is terminated following the completion of a Unit 2 SAT functionality assessment and physical restoration of the Unit 2 SATs supplying ESF Bus 241 and Bus 242.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records System (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Steven West, Director
Division of Reactor Projects

Docket No. 05000455
License No. NPF-66

Enclosure: Inspection Report 05000455/2012008
w/Attachments:
1. Supplemental Information
2. Special Inspection Team Charter
3. Timeline of Events

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Letter to M. Pacilio from S. West dated March 27, 2012

SUBJECT: BYRON UNIT 2 - NRC SPECIAL INSPECTION TEAM (SIT) REPORT 05000455/2012008

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