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

April 25, 2016

Mr. Bryan C. Hanson
Senior VP, Exelon Generation Company, LLC
President and CNO, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BYRON STATION, UNITS 1 AND 2 NRC INTEGRATED INSPECTION REPORT 05000454/2016001; 05000455/2016001

Dear Mr. Hanson:

On March 31, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Byron Station, Units 1 and 2. The enclosed report documents the results of this inspection, which were discussed on April 12, 2016, with Mr. Mark Kanavos, and other members of your staff.

Based on the results of this inspection, the NRC has identified one issue that was evaluated under the risk significance determination process as having very low safety significance (Green). The NRC has also determined that a violation was associated with this issue. This violation is being treated as a Non-Cited Violation (NCV), consistent with Section 2.3.2 of the Enforcement Policy. The NCV is described in the subject inspection report.

If you contest the violation or significance of the NCV, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555–0001, with copies to: (1) the Regional Administrator, Region III; (2) the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; and (3) the NRC Resident Inspector at the Byron Station.

In addition, if you disagree with the cross-cutting aspect assigned to the finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region III, and the NRC Resident Inspector at the Byron Station.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390, “Public Inspections, Exemptions, Requests for Withholding,” 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’s Public Document Room or from the Publicly Available Records System component of the NRC's Agencywide Documents Access and Management 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/

Eric R. Duncan, Chief
Branch 3
Division of Reactor Projects

Docket Nos. 50–454; 50–455
License Nos. NPF–37; NPF–66

Enclosure:
IR 05000454/2016001; 05000455/2016001

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	05000454; 05000455
License Nos:	NPF–37; NPF–66
Report No:	05000454/2016001; 05000455/2016001
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	Byron, IL
Dates:	January 1 through March 31, 2016
Inspectors:	J. McGhee, Senior Resident Inspector J. Draper, Resident Inspector J. Cassidy, Senior Health Physicist I. Khan, Reactor Inspector C. Thompson, Resident Inspector, Illinois Emergency Management Agency
Approved by:	E. Duncan, Chief Branch 3 Division of Reactor Projects

Enclosure

TABLE OF CONTENTS

SUMMARY

Inspection Report 05000454/2016001, 05000455/2016001; 01/01/2016–03/31/2016; Byron Station, Units 1 and 2; Other Activities.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. One Green finding was identified by the inspectors. The finding was considered a Non-Cited Violation (NCV) of U.S. Nuclear Regulatory Commission (NRC) regulations. The significance of inspection findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," dated April 29, 2015. Cross-cutting aspects are determined using IMC 0310, "Aspects Within the Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated February 4, 2015. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG–1649, "Reactor Oversight Process," dated February 2014.

Cornerstone: Initiating Events

- Green. A finding of very low safety significance and associated non-cited violation (NCV) of Technical Specification (TS) Limiting Condition for Operation (LCO) 3.0.4 was self-revealed when the licensee transitioned Unit 1 to Mode 3 with the turbine trip function of the Solid State Protection System (SSPS) disabled although the turbine trip function was required by TS LCO 3.3.2 to be operable in Mode 3. Upon identification, the licensee immediately manually tripped the turbine and restored the automatic turbine trip function. The licensee entered the issue into the corrective action program (CAP) and initiated actions to revise the mode change checklist and affected surveillance procedures.

  The inspectors determined that the finding was of more than minor safety significance because it was associated with the Configuration Control aspect of the Initiating Events Cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions. The finding was Green because the manual turbine trip and main steam isolation functions were not affected by the finding. The inspectors determined that the finding had a cross-cutting aspect of Work Management in the area of Human Performance (H.5) because the licensee failed to plan, control, and execute work activities such that nuclear safety was the overriding priority. [Section 4OA3.1]

REPORT DETAILS

Summary of Plant Status

During this inspection period, both Unit 1 and 2 at Byron Station were periodically scheduled to vary electrical output by the grid operator, PJM, to ramp down a few hundred megawatts for short periods to help ease congestion on the transmission system or to support the economic dispatch agreement between Exelon and PJM.

Unit 1

Unit 1 began the period operating at full power and continued to operate at power levels directed by PJM with no significant equipment issues until March 17, 2016, when a damaged insulator was identified in the 345 KV switchyard during an inspection after high winds required the station to enter abnormal operating procedures. After coordinating with PJM and Commonwealth Edison, the decision was made to immediately repair the insulator and Unit 1 power was reduced to 62 percent. Insulators on switchyard Bus 10 were repaired and power was restored to 100 percent on March 18, 2016.

Unit 2

Unit 2 began the period at full power and operated at scheduled power levels for the entire inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

.1 Readiness of Offsite and Alternate AC Power Systems

a. Inspection Scope

The inspectors verified that plant features and procedures for operation and continued availability of offsite and alternate alternating current (AC) power systems during adverse weather were appropriate. The inspectors reviewed the licensee's procedures affecting these areas and the communications protocols between the transmission system operator (TSO) and the plant to verify that the appropriate information was being exchanged when issues arose that could impact the offsite power system. Examples of aspects considered in the inspectors' review included:

- coordination between the TSO and the plant during an off-normal or emergency event;
- explanation for the event;
- an estimate of when the offsite power system would be returned to a normal state; and
- notification from the TSO to the plant when the offsite power system was returned to normal.

The inspectors also verified that plant procedures addressed measures to monitor and maintain the availability and reliability of both the offsite AC power system and the onsite

alternate AC power system prior to or during adverse weather conditions. Specifically, the inspectors verified that the procedures addressed the following:

- actions to be taken when notified by the TSO that the post-trip voltage of the offsite power system at the plant would not be acceptable to assure the continued operation of the safety-related loads without transferring to the onsite power supply;
- compensatory actions identified to be performed if it would not be possible to predict the post-trip voltage at the plant for the current grid conditions;
- re-assessment of plant risk based on maintenance activities which could affect grid reliability, or the ability of the transmission system to provide offsite power; and
- required communications between the plant and the TSO when changes at the plant could impact the transmission system, or when the capability of the transmission system to provide adequate offsite power was challenged.

The inspectors also reviewed CAP items to verify that the licensee was identifying adverse weather issues at an appropriate threshold and entering them into their CAP in accordance with station corrective action procedures.

This inspection constituted one readiness of offsite and alternate AC power systems sample as defined in Inspection Procedure (IP) 71111.01–05.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- 2A containment spray (CS) while 2B CS was out of service for planned maintenance;
- Essential service water (SX) alignment to Unit 1 and 2 component cooling water heat exchangers following system realignment; and
- 2B diesel generator (DG) during 2A DG work window.

The inspectors selected these systems based on their risk significance relative to the Reactor Safety Cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, the Updated Final Safety Analysis Report (UFSAR), Technical Specification (TS) requirements, outstanding work orders (WOs), issue reports (IRs), and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and

operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP with the appropriate significance characterization.

These activities constituted three partial system walkdown samples as defined in IP 71111.04–05.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05)

.1 Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on the availability, accessibility, and condition of firefighting equipment in the following risk-significant plant areas:

- Unit 1 turbine building 426 elevation;
- Unit 2 turbine building 426 elevation;
- Unit 1 and 2 turbine building 451 elevation;
- Unit 1 Division 11 miscellaneous electrical equipment room;
- Unit 1 Division 12 miscellaneous electrical equipment room; and
- Unit 2 Division 22 auxiliary building 426 elevation electrical penetration area.

The inspectors reviewed these areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant; effectively maintained fire detection and suppression capability; maintained passive fire protection features in good material condition; and implemented adequate compensatory measures for out-of-service, degraded or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. The inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP.

These activities constituted six quarterly fire protection inspection samples as defined in IP 71111.05–05.

b. Findings

No findings were identified.

1R06 Flooding (71111.06)

.1 Internal Flooding

a. Inspection Scope

The inspectors reviewed selected risk-important plant design features and licensee procedures intended to protect the plant and its safety-related equipment from internal flooding events. The inspectors reviewed flood analyses and design documents, including the UFSAR, engineering calculations, and abnormal operating procedures to identify licensee commitments. In addition, the inspectors reviewed licensee drawings to identify areas and equipment that may be affected by internal flooding caused by the failure or misalignment of nearby sources of water, such as the fire suppression or the circulating water systems. The inspectors also reviewed the licensee's corrective action documents with respect to past flood-related items identified in the CAP to verify the adequacy of the corrective actions. The inspectors performed a walkdown of the following plant areas to assess the adequacy of flood barriers, verify drains and sumps were clear of debris and were operable, and that the licensee complied with its commitments:

- Unit 1 residual heat removal pump and containment spray pump rooms; and
- Unit 2 residual heat removal pump and containment spray pump rooms.

This inspection constituted one internal flooding sample as defined in IP 71111.06–05.

b. Findings

No findings were identified.

1R07 Annual Heat Sink Performance (71111.07)

.1 Heat Sink Performance

a. Inspection Scope

The inspectors reviewed the licensee's testing of the 1A safety injection pump cubicle cooler heat exchanger to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors compared the licensee's observations with the acceptance criteria, the correlation of scheduled testing and the frequency of testing, and the impact of instrument inaccuracies on testing results. The inspectors also verified that test acceptance criteria considered differences between test design conditions and testing conditions.

This annual heat sink performance inspection constituted one sample as defined in IP 71111.07–05.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11)

.1 Resident Inspector Quarterly Review of Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

On March 1, 2016, the inspectors observed a crew of licensed operators in the plant's simulator during licensed operator requalification training. The inspectors verified that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and that training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- clarity and formality of communications;
- the crew's ability to take timely actions in the conservative direction;
- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of abnormal and emergency procedures;
- control board manipulations;
- oversight and direction from supervisors; and
- the crew's ability to identify and implement appropriate TS and Emergency Plan actions/notifications.

The crew's performance in these areas was compared to pre-established operator action expectations and successful critical task completion requirements.

This inspection constituted one quarterly licensed operator requalification program simulator sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observations During Periods of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On March 17, 2016, the inspectors observed operators and maintenance technicians in the control room performing a circuit card replacement for the feedwater pump net positive suction head control circuit. The inspectors also observed the operating crew lowering reactor power from full power to 63 percent of rated electrical output in response to emergent switchyard repair activities. These were activities that required heightened awareness and were related to increased risk. The inspectors evaluated the following areas:

- licensed operator performance;
- clarity and formality of communications;
- the crew's ability to take timely actions in the conservative direction;

- prioritization, interpretation, and verification of annunciator alarms;
- correct use and implementation of procedures;
- control board and equipment manipulations; and
- oversight and direction from supervisors.

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and task completion requirements.

This inspection constituted one quarterly licensed operator heightened activity/risk sample as defined in IP 71111.11–05.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12)

.1 Routine Quarterly Evaluations

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk-significant maintenance rule functions:

- DC–02 function–trains 112C and 212B (safety-related direct current (DC) power) reliability approaching threshold;
- PR–02 function–process radiation monitoring system failures for emergency core cooling system (ECCS) cubicle monitors;
- CB–02 function–condensate and condensate booster systems return to (a)(2) status after completion of (a)(1) action plan and monitoring; and
- AF–07 function–auxiliary feedwater (AF) flow control.

The inspectors reviewed events including those in which ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- implementing appropriate work practices;
- identifying and addressing common cause failures;
- scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule;
- characterizing system reliability issues for performance;
- charging unavailability for performance;
- trending key parameters for condition monitoring;
- ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification; and
- verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2), or appropriate and adequate goals and corrective actions for systems classified as (a)(1).

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance

effectiveness issues were entered into the CAP with the appropriate significance characterization.

This inspection constituted four quarterly maintenance effectiveness samples as defined in IP 71111.12–05.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13)

.1 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed:

- 1A essential service water pump out-of-service for planned maintenance, 1A auxiliary feedwater pump maintenance, and 2A DG tripped during a non-emergency start during the week of January 11, 2016;
- 1B essential service water pump out-of-service for maintenance, 1B residual heat removal pump out of service for planned maintenance, 2B containment spray pump out-of-service for cooler maintenance and surveillance, required schedule changes due to grid operator declaration of cold weather alert on January 19, 2B auxiliary feedwater out-of-service during surveillance activities, and 2B containment spray out-of-service during the week of January 18, 2016;
- inadequate test methodology identified for the auxiliary feedwater pump suction pressure transfer loops resulting in a missed TS surveillance; 2A DG out-of-service for greater than 72 hours for 2-year preventative maintenance activities during the week of February 8, 2016;
- 2B DG out-of-service for greater than 72 hours for 2-year preventative maintenance activities during the week of February 22, 2016;
- 1B and 2B auxiliary feedwater emergent modifications and associated schedule changes during the week of March 7, 2016; and
- 1B auxiliary feedwater heat exchanger inspection and surveillances, 1B solid state protection system test, emergency troubleshooting on 1B containment spray, 2B DG testing, and 1A auxiliary feedwater flow control valve calibration during the week of March 28, 2016.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. The inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or on-shift senior reactor operators, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems to verify risk analysis assumptions were valid and credited risk management actions were in place.

These maintenance risk assessments and emergent work control activities constituted seven samples as defined in IP 71111.13–05.

b. Findings

No findings were identified.

1R15 Operability Determinations and Functional Assessments (71111.15)

.1 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following issues:

- operability of the AF system when flow control valves were failed open with instrument air isolated;
- 2A DG trip during monthly surveillance testing;
- main control room ventilation chiller condenser inspection identified degraded metal surfaces;
- degraded coating identified in lining of 2A diesel oil storage tank;
- evaluation of unprotected auxiliary/secondary structural steel attached to protected structural steel;
- fire protection (American Society of Mechanical Engineers Class 3) piping through-wall leak in auxiliary building at 346' elevation line/column L19; and
- 1B containment spray pump trip light not lit in main control room.

The inspectors selected these potential operability issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and UFSAR to the licensee's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sample of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

This operability inspection constituted seven samples as defined in IP 71111.15–05.

b. Findings

(1) (Open) Unresolved Item: Failure to Enter Technical Specification Limiting Condition for Operation Action Requirement with Auxiliary Feedwater Flow Control Valves Failed Open

Introduction: The inspectors identified an Unresolved Item (URI) associated with the concern that the licensee failed to enter a TS LCO action requirement when all air was

isolated to the actuators to the auxiliary feedwater flow control valves, failing them open and unable to be throttled or closed from the control room.

Description: On January 3, 2016, the licensee generated Issue Report (IR) 2607148 which requested clarifying guidance from engineering for assessing operability of the 1/2AF005A–H auxiliary feedwater flow control valves to the steam generators, when air is isolated from the valve actuators. The IR stated that when procedure BISR 3.4.2–200, “Surveillance Calibration of Aux Feedwater to Steam Generators A, B, C and D Flow Control Loops,” was performed, all air was isolated from the auxiliary feedwater flow control valves to fail them open during the calibration. This was intended to maintain operability of the auxiliary feedwater system during the calibration.

At each Byron unit, each of the two auxiliary feedwater pumps had a separate flow path to each of the steam generators, and each flow path had an air-operated flow control valve, a motor-operated containment isolation valve, and a check valve in the flow path. The flow control valves used instrument air as the motive force to throttle and close the valves. Upon a loss of air to the actuator, the flow control valves were designed to fully open via spring pressure, allowing auxiliary feedwater flow to the steam generators. In 2012, the licensee installed safety-related accumulators on each auxiliary feedwater train to supply air to the auxiliary feedwater flow control valve actuators upon a loss of instrument air. This air supply was designed so that if one of the steam generators experienced a steam generator tube rupture and the containment isolation valve in the flow path to that steam generator failed to close, the control room operators could close the flow control valve to limit or isolate auxiliary feedwater flow to the failed steam generator until an equipment operator could locally secure the flow control valve in its closed position. This modification was performed to support the licensee’s license amendment request for a measurement uncertainty recapture uprate so that operator actions could be credited to prevent the steam generator with a ruptured tube from overfilling and challenging the containment function.

Upon completion of the modifications, the licensee updated Table 15.0–7, “Plant Systems and Equipment Credited for Transients and Accident Conditions,” in the Accident Analysis section of the licensee’s UFSAR to include the AF Accumulator Tanks as engineered safeguard feature (ESF) equipment credited for steam generator tube rupture incidents. The safety evaluation in Chapter 10 of the UFSAR was also updated for the Auxiliary Feedwater System to state that in the event of a steam generator tube rupture, operator action was required to isolate auxiliary feedwater flow to the ruptured steam generator within certain time requirements, and that in the event that the containment isolation valve failed to close, the flow path could still be isolated by closing the AF005 valves, with air accumulators sized to ensure sufficient time for local operator action to secure the AF005 valves in the closed position.

In response to IR 2607148, the licensee’s regulatory assurance department documented that the safety function of TS LCO 3.7.5, “Auxiliary Feedwater System,” was intended to be limited to supply water to the steam generators for heat removal and that this should not be changed in favor of any UFSAR design analysis. The IR concluded that Operability per the TS was not applicable, and operations did not need to place the unit in any TS condition statement with the AF005 valves failed open with no instrument air supply during the associated instrument calibrations. From the time the licensee received the measurement uncertainty recapture license amendment on February 7, 2014, through March 22, 2016, the licensee had failed open all four AF005

valves in each train of auxiliary feedwater using BISR 3.4.2–200 at least five times per train, and has not entered a TS LCO during most of these time periods.

The regulations stated in 10 CFR 50.26(c)(2)(ii)(C) that a TS LCO of a nuclear reactor must be established for each SSC that is part of the primary success path and which functions or actuates to mitigate a design basis accident or transient that assumes the failure of/or presents a challenge to the integrity of a fission product barrier.

The inspectors were concerned that when all air is isolated to the auxiliary feedwater flow control valve actuators, operators may not be able to throttle or isolate flow to a ruptured steam generator quickly enough to prevent overfill of the steam generator, assuming the motor-operated containment isolation valve fails to close, which could challenge the integrity of containment. As such, the inspectors were concerned that the licensee failed to enter a TS LCO action requirement when the air to the actuator was isolated. To determine whether a performance deficiency or violation exists, the inspectors need to determine if a TS LCO should have been established for the ability of the AF005 valves to close to mitigate a steam generator tube rupture event, and if the licensee's modifications and license amendment requests properly addressed the establishment of an LCO for this function of the SSC. **(URI 05000454/2016001–01, 05000455/2016001–01; Failure to Enter Technical Specification Limiting Condition for Operation Action Requirement with Auxiliary Feedwater Flow Control Valves Failed Open)**

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following modification:

- Temporary Configuration Change Package (TCCP) 404997; Remove Auxiliary Feedwater Diesel Air Intake Elbow and Blank Off Turbine Building Air Intake.

This temporary modification was implemented as a result of an unanalyzed condition identified at another Exelon station and determined to be applicable to Byron Station. The condition was reported to the NRC in Event Notification 51772.

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screening for the temporary modification against the design basis, UFSAR, and TS, to verify that the modification did not affect the operability or availability of the affected systems. The inspectors observed ongoing and completed work activities to ensure that the modification was installed as directed and consistent with the design control documents, the modification operated as expected, post-modification testing adequately demonstrated continued system operability, and that operation of the modification did not impact the operability of any interfacing systems. The inspectors verified that relevant procedure, design, and licensing documents were properly updated. Lastly, the inspectors discussed the plant modification with operations, engineering, and training personnel to ensure that the individuals were aware of how the operation with the plant modification in place could impact overall plant performance.

Additional questions regarding impact of a fire in the auxiliary building on the auxiliary feedwater diesel driven pumps were discussed at the end of the inspection period which required the inspection to continue into the second quarter of 2016. Additional information regarding this inspection sample will be documented in Inspection Report 05000454/2016002, 05000455/2016002. This partial inspection did not constitute a completed sample as defined in IP 71111.18–05.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19)

.1 Post-Maintenance Testing

a. Inspection Scope

The inspectors reviewed the following post-maintenance (PM) testing activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- replace 480 VAC breaker bucket for feedwater isolation valve 1FW009C;
- replace 2A DG non-emergency trip air check valve 2DG5241A;
- repair of 2A DG leaking fuel line and broken lifter, and adjust governor for surging during cooldown;
- 2-year preventative maintenance overhaul for 2B DG and emergent voltage adjust circuit card replacement;
- repair of hydraulic actuator for feedwater isolation valve 1FW009C; and
- 1B auxiliary feedwater pump lube oil cooler inspection.

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following: the effect of testing on the plant had been adequately addressed, testing was adequate for the maintenance performed; acceptance criteria were clear and demonstrated operational readiness, test instrumentation was appropriate, tests were performed as written in accordance with properly reviewed and approved procedures, equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion), and test documentation was properly evaluated. The inspectors evaluated the activities against TS, UFSAR, 10 CFR Part 50 requirements, and licensee procedures to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with post-maintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety.

This inspection constituted six post-maintenance testing samples as defined in IP 71111.19–05.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22)

.1 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

- 1BOSR 0.5–2.AF.3–1/2; Unit One Auxiliary Feedwater Valves Train A/B Indication Test (routine);
- 1BOSR 0.5–3.AF.1–2; Unit One ASME Surveillance Requirements for the B Train Auxiliary Feedwater SX Supply Valves (IST);
- 1/2BISR 3.2.2–001/2; Channel Operation Test of Train A/B Auxiliary Feedwater Pump Suction Pressure Loop (routine); and
- 1BOSR 3.2.8–644A; Unit One Engineered Safety Feature Actuation System (ESFAS) Instrument Slave Relay Surveillance (Train A Automatic Containment Spray–K644) (routine).

The inspectors observed in-plant activities and reviewed procedures and associated records to determine the following:

- did preconditioning occur;
- were the effects of the testing adequately addressed by control room personnel or engineers prior to the commencement of the testing;
- were acceptance criteria clearly stated, sufficient to demonstrate operational readiness, and consistent with the system design basis;
- was plant equipment calibration correct, accurate, and properly documented;
- were as-left setpoints within required ranges; and was the calibration frequency in accordance with TSs, the UFSAR, plant procedures, and applicable commitments;
- was measuring and test equipment calibration current;
- was the test equipment used within the required range and accuracy, and were applicable prerequisites described in the test procedures satisfied;
- did test frequencies meet TS requirements to demonstrate operability and reliability;
- were tests performed in accordance with the test procedures and other applicable procedures;
- were jumpers and lifted leads controlled and restored where used;
- were test data and results accurate, complete, within limits, and valid;
- was test equipment removed following testing;
- where applicable for In-Service Test (IST) activities, was testing performed in accordance with the applicable version of Section XI of the ASME Code and were reference values consistent with the system design basis;
- was the unavailability of the tested equipment appropriately considered in the performance indicator (PI) data;

- where applicable, were test results not meeting acceptance criteria addressed with an adequate operability evaluation or was the system or component declared inoperable;
- where applicable for safety-related instrument control surveillance tests, was the reference setting data accurately incorporated into the test procedure;
- was equipment returned to a position or status required to support the performance of its safety functions following testing;
- were problems identified during the testing appropriately documented and dispositioned in the licensee's CAP;
- were annunciators and other alarms demonstrated to be functional and were setpoints consistent with design requirements; and
- were alarm response procedure entry points and actions consistent with the plant design and licensing documents.

This inspection constituted three routine surveillance testing samples and one in-service test sample as defined in IP 71111.22, Sections–02 and–05.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on March 3, 2016, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the Main Control Room simulator and the Technical Support Center (TSC) to determine whether the event classifications, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the CAP. As part of the inspection, the inspectors reviewed the drill package.

This emergency preparedness drill inspection constituted one sample as defined in IP 71114.06–06.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Security

4OA1 Performance Indicator Verification (71151)

.1 Unplanned Scrams Per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams Per 7000 Critical Hours PI for Byron Station, Units 1 and 2, for the period from the first quarter 2015 through the fourth quarter 2015. To determine the accuracy of the PI data reported during those periods, guidance contained in Nuclear Energy Institute (NEI) 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, dated August 31, 2013, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports and NRC Integrated Inspection Reports for the period of January 2015 through December 2015 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator.

This inspection constituted two unplanned scrams per 7000 critical hours samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.2 Unplanned Scrams with Complications

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Scrams with Complications PI for Byron Station, Units 1 and 2, for the period from the first quarter 2015 through the fourth quarter 2015. To determine the accuracy of the PI data reported during those periods, guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, event reports and NRC Integrated Inspection Reports for the period of January 2015 through December 2015 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator.

This inspection constituted two unplanned scrams with complications samples as defined in IP 71151–05.

b. Findings

No findings were identified.

.3 Unplanned Transients Per 7000 Critical Hours

a. Inspection Scope

The inspectors sampled licensee submittals for the Unplanned Transients Per 7000 Critical Hours PI for Byron Station, Units 1 and 2, for the period from the first quarter 2015 through the forth quarter 2015. To determine the accuracy of the PI data reported during those periods, guidance contained in NEI 99–02, "Regulatory Assessment Performance Indicator Guideline," Revision 7, was used. The inspectors reviewed the licensee's operator narrative logs, issue reports, maintenance rule records, event reports and NRC Integrated Inspection Reports for the period of January 2015 through December 2015 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator.

This inspection constituted two unplanned transients per 7000 critical hours samples as defined in IP 71151–05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Routine Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: identification of the problem was complete and accurate; timeliness was commensurate with the safety significance; evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, functionality and operability issues, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to correct the issue.

These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter and documented in Section 1 of this report.

b. Findings

No findings were identified.

.2 Daily Corrective Action Program Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings were identified.

.3 Annual Follow-up of Selected Issues: Degraded Batteries on FLEX Diesel Generators Due to Incorrectly Wired Heat Trace Thermostat

a. Inspection Scope

During a review of items entered in the licensee's CAP, the inspectors recognized a corrective action item documenting a loss of power to the control panel of the 'C' FLEX diesel generator (IR 2582798). The IR identified that during a routine surveillance test of the FLEX diesel generators, the licensee found that the control panel for the 'C' generator didn't have power. Upon further investigation, the licensee identified that the batteries for the diesel generator had been damaged due to excessive operation of heat trace wiring for the batteries. The heat traces were controlled by a thermostat which was designed to prevent the batteries from becoming degraded if the ambient temperature became cold. The licensee identified that the heat traces had been in operation even though the ambient temperature inside the building where the FLEX diesels were stored remained above the thermostat setpoint. After additional troubleshooting, the licensee identified that the thermostat was wired incorrectly such that the heat trace remained energized when it was supposed to be de-energized, and that this condition existed on all four FLEX diesel generators. The licensee also identified that another site within the licensee's fleet had previously identified degraded batteries due to heat trace damage prior to the issue being identified at Byron.

The inspectors reviewed the licensee's CAP documents related to the issue, including the Work Group Evaluation performed by Engineering, as well as supply management procedures for the acceptance of augmented quality equipment. The inspectors also reviewed communications between the licensee and the other sites within the fleet as well as with the vendor for the FLEX diesel generators. The inspectors performed this review to identify any weaknesses in the licensee's CAP process, including:

- complete, accurate, and timely documentation of the identified problem;
- evaluation and timely disposition of functionality and reportability issues;
- consideration of extent of condition and cause, generic implications, common cause, and previous occurrences;
- identification of the causes of the problem;

- implementation of corrective actions that are appropriately focused to correct the problem; and
- operating experience is adequately evaluated for applicability, and applicable lessons learned are communicated to appropriate organizations and implemented.

During the review, the inspectors identified that the licensee entered the issue into the CAP upon identification of the issue, and that although a more thorough review and inspection of the generators when they were initially received onsite could have identified the wiring issue, the requirements associated with the battery heaters did not require such an inspection. The inspectors also identified that the licensee evaluated the issue promptly to determine whether the diesels could perform their intended function, and assessed maintenance rule functional failures as required by their program. The licensee also considered the extent of condition both at Byron and across the industry, including submitting operating experience communications to both the fleet and the industry. The inspectors identified that the licensee promptly communicated with the vendor of the generators to identify the cause of the damaged batteries and to initiate immediate corrective actions to shut off the heat traces and replace the batteries with similar batteries to restore functionality, as well as long-term corrective actions of procuring replacement batteries of the original design in a time frame commensurate with safety.

The inspectors noted that while another site within the licensee's fleet identified damaged batteries several months before Byron identified the issue, the other site was not able to identify the wiring issue as the cause, so the other site did not communicate the issue. Therefore, the operating experience from the other site was not readily available to Byron.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152–05.

b. Findings

No findings were identified.

.4 Annual Follow-up of Selected Issues: Review of Enforcement Discretion Non-Cited Violations Identified During the 2014 Cyber-Security Inspection 2013408 and Associated Corrective Action Documents

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents, specifically IR 01522300, "Cyber Security Reevaluation of EPT [Emergency Preparedness–TSC] network boundary devices;" IR 01522309, "Cyber Security: Scoping of physical security digital assets;" and IR 01507225, "Cyber Security: BRW LL MS 4 [Braidwood Lessons Learned Milestone 4] issues with virus scanning kiosk." The inspectors interviewed personnel, performed walkdowns, verified the completion of and assessed the adequacy of the corrective actions taken in response to the two NRC–identified NCVs and a licensee-identified NCV that was granted enforcement discretion.

The inspectors review and evaluation was focused on the two NRC and one licensee–identified cyber-security NCVs to ensure corrective actions: were complete, accurate, and timely; considered extent of condition; provided appropriate classification and prioritization; provided identification of root and contributing causes; were appropriately focused; resulted in the correction of the identified problem; identified negative trends; adequately evaluated operating experience for applicability; and communicated applicable lessons learned to appropriate organizations.

This review constituted one in-depth problem identification and resolution sample as defined in IP 71152–05.

b. Background

In accordance with Title 10, *Code of Federal Regulations* (CFR), Part 73, Section 54, "Protection of Digital Computer and Communication Systems and Networks (i.e., the Cyber-Security Rule), each nuclear power plant (NPP) licensee was required to submit to the NRC for review and approval a cyber-security plan (CSP) and an associated implementation schedule by November 23, 2009. Temporary Instruction (TI) 2201/004, "Inspection of Implementation of Interim Cyber Security Milestones 1–7," was developed to evaluate and verify each NPP licensee's ability to meet the interim milestone requirements of the Cyber-Security Rule. On July 8, 2013, the NRC completed an inspection at the Byron Station, Units 1 and 2, which evaluated the interim Cyber-Security Milestones 1–7. During performance of the TI, NCVs were identified and incorporated into the licensee's CAP. These NCVs were subsequently granted enforcement discretion following the Security Issues Forum (SIF) Meeting conducted on June 19, 2013. During the week of February 22, 2016, the inspectors reviewed the Cyber-Security Milestones 1–7 Inspection NCVs as a Problem Identification and Resolution) (PI&R) sample. The inspectors evaluated the CAP documents to determine the effectiveness of the licensee's corrective actions.

c. Observations

No observations were identified.

d. Findings

No findings were identified.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153)

.1 (Closed) Licensee Event Report 05000454/2015–006–00: Mode 3 Entered with Turbine Trip Safety Function Disabled Due to Safety–Related Relay Leads Lifted

a. Inspection Scope

On October 1, 2015, while Unit 1 was in Mode 3 finishing a refueling outage, the licensee identified that Unit 1 was in a condition that could have prevented fulfillment of the turbine trip safety function. Specifically, on September 30, 2015, while in Mode 5, the licensee had lifted leads to disable both trains of the turbine trip function of the SSPS. The leads were lifted to support the performance of surveillances, which was allowed in Modes 6, 5, and 4; however, the licensee failed to reinstall the leads to enable the turbine trip function prior to entering Mode 3 as required by TS. With both trains of

the turbine trip function disabled, the automatic turbine trip function of SSPS could not be fulfilled, though the ability of operators to manually trip the turbine was not affected. The licensee determined that the failure to enable the turbine trip function before entering Mode 3 was caused by a lack of rigor in station procedure 1BGP 100-1T3, “Mode 4 to 3 Checklist.” The licensee’s corrective actions included tripping the turbine and re-enabling the turbine trip function and revising the mode change checklist procedures and the surveillance procedures that involved disabling the turbine trip function of SSPS.

On November 30, 2015, the licensee submitted LER 05000454/2015–006–00. In addition to reporting the condition that could have prevented fulfillment of the turbine trip safety function in accordance with 10 CFR 50.73(a)(2)(v)(D), the licensee also documented in the Licensee Event Report (LER) that the event was reportable as an operation or condition which was prohibited by the plant’s TS in accordance with 10 CFR 50.73(a)(2)(i)(B). However, after further review of the event timeline, the inspectors identified that the licensee did not violate any required action completion time. Therefore, while the event was still reportable as a condition that could have prevented the fulfillment of a safety function, the event did not meet the reporting criteria for an operation or condition prohibited by TS. This LER is closed.

This event follow-up review constituted one sample as defined in IP 71153–05.

b. Findings

Introduction: A Green finding and NCV of TS LCO 3.0.4 for the licensee’s transition of Unit 1 into a mode of applicability with the requirements of LCO 3.3.2 not met was self-revealed on October 1, 2015. Specifically, with the turbine trip function of the SSPS disabled to support surveillance testing, operators transitioned Unit 1 from Mode 4, where the turbine trip function is not required, to Mode 3, where it was required by LCO 3.3.2.

Description: On September 30, 2015, Byron Station, Unit 1, was in Mode 5, making progress toward transitioning to Modes 4 and 3. While in Mode 5, the licensee performed calibrations and surveillance tests on valves associated with the main turbine. The licensee’s calibration and testing procedures allowed the licensee to disable the turbine trip function of the SSPS while the unit was in Modes 4, 5, or 6, as this function was only required in Modes 1, 2, and 3, per TS LCO 3.3.2, “ESFAS Instrumentation.” While the procedures included this allowance, they contained no reference to TS LCO 3.3.2. Additionally, while each of the testing procedures contained steps to restore the turbine trip function after testing was completed, the procedures also allowed the licensee to maintain the trip function disabled if a procedure that required the same leads to be lifted was to be performed directly after the completion of the procedure.

In accordance with the testing procedures, the licensee lifted leads associated with the protection relay and commenced testing. The status of the leads was documented in 1BGP 100–1T3, “Mode 4 to 3 Checklist,” and equipment status tags were hung on the control boards to indicate, “K640 relay leads are lifted.” When the licensee performed the calibrations and surveillances required for entry into Mode 3, Operations failed to identify that the lifted leads impacted TS LCO 3.3.2, so at 0059 on October 1, 2015, the operators transitioned Unit 1 to Mode 3 with the turbine trip function disabled.

The impact of the lifted leads on TS LCO 3.3.2 was not identified by the night shift operations crew nor during the dayshift operations crew's turnover. At 0906 on October 1, 2015, a reactor operator noted the equipment status tags and questioned the licensee's compliance with TS LCO 3.3.2 in Mode 3. As a result of this questioning, the licensee declared the turbine trip function inoperable. Because TS LCO 3.3.2 did not contain a required action for both trains of the turbine trip function being inoperable, the licensee entered TS LCO 3.0.3, which required the licensee to be in Mode 4 within 13 hours. The licensee manually tripped the turbine, landed the leads to enable the turbine trip function, and exited TS LCO 3.0.3 at 0946.

Analysis: The inspectors determined that the licensee's transitioning of Unit 1 to Mode 3 with the turbine trip function of the ESFAS Instrumentation inoperable was a performance deficiency. Using the guidance in IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, the inspectors determined that the performance deficiency was more than minor because it was associated with the Configuration Control attribute of the Reactor Safety–Initiating Events Cornerstone and adversely affected the cornerstone objective of limiting the likelihood of events that upset plant stability and challenge critical safety functions. Specifically, the performance deficiency affected the ESFAS's ability to automatically trip the turbine to prevent water carryover into the turbine, which could result in events such as high energy line break or flooding as a result of turbine damage. The inspectors also determined that this finding was self-revealed as the mode change checklist and the equipment status tags on the control boards made the condition readily detectable to any licensed operator in the control room, yet the impact of the condition was not recognized during the transition to Mode 3 nor during shift turnover activities.

To characterize the finding, the inspectors used IMC 0609, "Significance Determination Process," Attachment 4, "Initial Characterization of Findings." The inspectors determined that the finding affected the Initiating Events Cornerstone as it was a potential transient initiator contributor and external events initiator. Based on answering "No" to all of the questions in Table 3 of Attachment 4, the inspectors used IMC 0609, Appendix A, "The Significance Determination Process (SDP) for Findings At-Power," to determine the significance of the finding. The inspectors used the screening questions in Exhibit 1 to Appendix A to determine that a detailed risk evaluation was needed because the finding impacted the frequency of an internal flooding initiating event.

A Senior Reactor Analyst (SRA) performed a bounding risk evaluation for the delta core damage frequency (ΔCDF) for the failure of the automatic turbine trip function. A core damage event was very conservatively assumed to occur if the main turbine was not isolated following an event that required a turbine trip. The following inputs and assumptions were used:

- To determine the failure probability of not manually tripping the turbine following an event that required a turbine trip, the following was performed:
  - The Human Error Probability (HEP) that the operators would fail to manually trip the turbine was determined using the Byron Standardized Plant Analysis Risk (SPAR)-H human reliability analysis method (per NUREG/CR–6883). Using SPAR-H, only the Action portion of the task was evaluated to be applicable since the action to verify a turbine trip is performed expeditiously

following a reactor trip, and this action is frequently rehearsed by the operators during training evolutions. The Performance Shaping Factor (PSF) for “Stress” was determined to be “High,” with the other PSFs at a nominal value. This resulted in an HEP to manually trip the turbine of 2E–3.

- The failure-to-close probability of a main turbine stop valve is 1.5E–3 (per NUREG/CR–6928 Table A.2.22–6 for Hydraulic-Operated Valves). Since there are four main turbine stop valves that need to close to isolate the main turbine, the failure probability due to valve failure is 6.0E–3.

- The total failure probability of not manually tripping the turbine following an event that required a turbine trip is the sum of the HEP (2E–3) and the valve failure probability (6.0E–3) or 8.0E–3.

- To determine the failure probability of not manually closing the Main Steam Isolation Valves (MSIVs) following an event that required a turbine trip and in which the main turbine stop valves failed-to-close, the following was performed:

- The HEP that the operators would not manually close the MSIVs if the main turbine stop valves failed-to-close was determined using the SPAR-H human reliability analysis method (per NUREG/CR–6883). Using SPAR-H, only the Action portion of the task was evaluated to be applicable since the action to verify a turbine trip is performed expeditiously following a reactor trip, and this action is frequently rehearsed by the operators during training evolutions. The failure of the turbine stop valves to close would be readily identified and the requirement to then close the MSIVs would also then be readily identified. The PSF for “Stress” was determined to be “High,” with the other PSFs at a nominal value. This resulted in an HEP to manually close the MSIVs of 2E–3.

- The failure-to-close probability of an MSIV is 1.20E–3 (from the SPAR model version 8.27). Since there are four MSIVs that need to close to isolate the main turbine, the failure probability due to valve failure is 4.8E–3.

- The total failure probability of not manually closing the MSIVs following an event that required a turbine trip and in which the main turbine stop valves failed-to-close is the sum of the HEP (2E–3) and the valve failure probability (4.8E–3) or 6.8E–3.

The Exposure Time for the finding for when the automatic turbine trip function was disabled was approximately eight hours.

The frequency of a plant transient (e.g., a reactor trip) is 0.69/year per the Byron SPAR model. A frequency of 1.0/year was conservatively assumed for the requirement of a turbine trip following a plant event.

Using the above inputs and assumptions, a bounding ΔCDF was calculated for the failure to isolate the main turbine following an event that required a turbine trip:

$\Delta CDF = [1.0/year] \times [8\ hours/8760\ hours] \times [8.0E{-}3] \times [6.8E{-}3]$

$= 5.0E{-}8/year$

Based on the Detailed Risk Evaluation, the SRA determined that the finding was of very low safety significance (Green).

The inspectors determined that the finding had a cross-cutting aspect of Work Management in the area of Human Performance (H.5) in that the licensee failed to implement a process of planning, controlling, and executing work activities such that nuclear safety is the overriding priority, including the identification and management of risk commensurate to the work and the need for coordination with different groups. Specifically, the licensee's surveillance procedures that controlled the work activities did not include information to assist the operators in understanding the impact of disabling the turbine trip on TSs. Similarly, the information documented on the Mode Change checklist and equipment status tags did not describe the impact of the lifted leads on the TS functions of the system such that it was adequately communicated to subsequent shifts. Also, work activities were modified from the original work schedule such that procedures that had Mode-dependent actions were in progress during the Mode change.

Enforcement: Byron Unit 1 TS LCO 3.0.4 requires, in part, that when an LCO is not met, entry into a Mode in the Applicability shall only be made when the associated actions to be entered permit continued operation in the Mode for an unlimited period of time, after performance of a risk assessment addressing inoperable systems and components, or when an allowance is stated.

Contrary to the above, on October 1, 2015, the licensee transitioned Unit 1 into Mode 3 with LCO 3.3.2 not met due to the turbine trip function of the SSPS disabled. The associated actions did not allow continued operation for an unlimited period of time, the licensee did not perform a risk assessment, and an allowance was not stated for this LCO. During the time that Unit 1 was in Mode 3 with the turbine trip disabled, no automatic turbine trip was required, so there was no actual safety consequence.

Upon identification of the issue, the licensee immediately tripped the turbine and restored the automatic turbine trip function. This violation is being treated as an NCV, consistent with Section 2.3.2 of the Enforcement Policy. The violation was entered into the CAP as IR 2563847. **(NCV 05000454/2016001–02, Entry into Mode 3 with Turbine Trip Function of SSPS Disabled)**

4OA5 Other Activities

.1 (Closed) Reduced Decay Time URI 05000454/2013004–04; 05000455/2013004–04)

On August 28, 2013, the inspectors identified that changes were made to the Technical Requirements Manual that reduced the required in-core decay time from greater than 100 hours to less than 48 hours. The inspectors could not immediately assess whether an anticipated accident, such as a dropped fuel bundle, that occurred within this shortened decay time might result in a significant new radiological hazard for onsite workers or members of the public. Consequently, the inspectors opened a URI in IR 05000454/2013004; 05000455/2013004 on November 14, 2013.

Subsequently, the inspectors reviewed the parameters of an accident such as a dropped fuel bundle. Chapter 15, "Accident Analysis," of the UFSAR details the analysis parameters in section 15.7.4, "Fuel Handling Accidents". The inspectors noted that the USFAR previously indicated that the radiation monitors in the fuel handling building in the vicinity of a postulated fuel handling accident would be off-scale high, but still functional, with 100 hours of in-core decay time. However, the USFAR was silent whether the radiation monitor would remain functional with only 48 hours of in-core decay time and the licensee did not have current calculations to establish expected dose rates in the area of the radiation monitors. The licensee subsequently performed a calculation of dose rates due to a fuel handling accident to address the inspectors' questions. Additionally, the inspectors consulted with staff members from the Radiation Protection and Consequences Branch in the Office of Nuclear Reactor Regulation to ensure the scope of this review appropriately applied the alternative radiological source terms for evaluating design basis accidents at nuclear power reactors.

The inspectors determined that the reduction of in-core decay time did not result in a more than minimal increase in the consequences of this accident for members of the public or to operators than previously evaluated in the final safety analysis report. Additionally, the equipment qualification for the radiation monitors was not adversely impacted by the dose rates expected to be experienced during a postulated fuel handling accident with 48 hours of in-core decay time. This issue is closed.

4OA6 Management Meetings

.1 Exit Meeting Summary

On April 12, 2016, the inspectors presented the inspection results to Mr. M. Kanavos and other members of the licensee staff. The licensee acknowledged the issues presented. The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

.2 Interim Exit Meetings

Interim exits were conducted for:

- The inspection results for URI 2013004–04, "Reduced Decay Time," with Mr. D. Spitzer, Regulatory Assurance Manager, on January 29, 2016.

The inspectors confirmed that none of the potential report input discussed was considered proprietary. Proprietary material received during the inspection was returned to the licensee.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

M. Kanavos, Site Vice President
T. Chalmers, Plant Manager
D. Spitzer, Regulatory Assurance
J. Armstrong, Security
P. Boyle, Work Management/Outage
B. Jacobs, Project Management
E. Richards, Maintenance
B. Currier, Design Engineering
E. Hernandez, Operations
C. Keller, Engineering
K. McGuire, Chemistry Manager
A. Corrigan, Regulatory Assurance
L. Zurawski, Regulatory Assurance
B. Barton, Radiation Protection Manager

Nuclear Regulatory Commission

E. Duncan, Chief, Reactor Projects Branch 3

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000454/2016001–01 05000455/2016001–01	URI	Failure to Enter Technical Specification Limiting Condition for Operation Action Requirement with Auxiliary Feedwater Flow Control Valves Failed Open
05000454/2016001–02	NCV	Entry into Mode 3 with Turbine Trip Function of SSPS Disabled

Closed

05000454/2013004–04 05000455/2013004–04	URI	Reduced Decay Time
05000454/2015–006–00	LER	Mode 3 Entered with Turbine Trip Safety Function Disabled Due to Safety–Related Relay Leads Lifted
05000454/2016001–02	NCV	Entry into Mode 3 with Turbine Trip Function of SSPS Disabled

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.

Section 1R01

- OP–AA–108–107, Revision 004; Switchyard Control
- OP–AA–108–107–1001, Revision 006; Station Response to Grid Capacity Conditions
- OP–AA–108–107–1002, Revision 009; Interface Procedure Between COMED/PECO and Exelon Generation Nuclear/Power for Transmission Operations
- Unit 1/2 Standing Order 16–012 Revision 1; Advanced Nuclear Dispatch

Section 1R04

- BOP CS–M1, Revision 13; Containment Spray Valve Lineup
- BOP CS–M1A, Revision 3; Containment Spray Train A Valve Lineup
- BOP SX–M1, Essential Service Water System Valve Lineup
- M–42; Diagram of Essential Service Water
- IR 1665798; 2VD03CB 2B DG Room Exhaust Fan Does Not Run
- IR 2416984; Failed PMT: 2B DG Room Exhaust Fan
- IR 2444013; 2B DG Room Exhaust Fan Motor Needs Repair or Replacement
- M–54, Sheet 4B, Revision G; Diagram of Service Air (Diesel Generator Starting Air)
- M–152, Sheet 15, Revision S; Manufacturer's Supplement Diagram of Diesel Generator Control Diagram Shutdown System
- M–152, Sheet 10, Revision AD; Manufacturer's Supplemental Diagram of Diesel Generator Fuel Oil Schematic
- M–152, Sheet 14, Revision Z; Manufacturer's Supplemental Diagram of Diesel Generator Jacket Water Schematic
- M–152, Sheet 16, Revision I; Diagram of Diesel Generator Control Diagram Pressure Gauge Lines and Alarms
- M–152, Sheet 9, Revision AA; Manufacturer's Supplemental Diagram of Diesel Generator Lube Oil Schematic
- M–98, Revision P; Diagram of Diesel Generator Room 2A & 2B Ventilation System

Section 1R05

- Pre-Fire Plan FZ 8.5–2 Southwest, Revision 1; Turbine Bldg. 426"–0" Elevation Unit 2 General Area–SW
- Pre-Fire Plan FZ 8.5–2 Southeast, Revision 1; Turbine Bldg. 426"–0" Elevation Unit 2 General Area–SE
- Pre-Fire Plan FZ 8.5–2 Northwest, Revision 1; Turbine Bldg. 426"–0" Elevation Unit 2 General Area–NW
- Pre-Fire Plan FZ 8.5–2 Northeast, Revision 1; Turbine Bldg. 426"–0" Elevation Unit 2 General Area–NE
- Pre-Fire Plan FZ 8.5–1 Southwest, Revision 1; Turbine Bldg. 426"–0" Elevation Unit 1 General Area–SW
- Pre-Fire Plan FZ 8.5–1 Southeast, Revision 1; Turbine Bldg. 426"–0" Elevation Unit 1 General Area–SE

- Pre-Fire Plan FZ 8.5–1 Northwest, Revision 1; Turbine Bldg. 426"–0" Elevation Unit 1 General Area–NW
- Pre-Fire Plan FZ 8.5–1 Northeast, Revision 1; Turbine Bldg. 426"–0" Elevation Unit 1 General Area–NE
- Pre-Fire Plan FZ 5.6–1, Auxiliary Bldg. 451'–0" Elevation Division 11 Miscellaneous Electrical Equipment and Battery Room
- Pre-Fire Plan FZ 5.4–1, Auxiliary Bldg. 451'–0" Elevation Division 12 Miscellaneous Electrical Equipment and Battery Room
- Pre-Fire Plan FZ 8.6–0 Southwest End, Revision 1; Turbine Bldg. 451"–0" Elevation Unit 1 General Area–SW End
- Pre-Fire Plan FZ 8.6–0 Southwest Center, Revision 1; Turbine Bldg. 451"–0" Elevation Unit 1 General Area–SW Center
- Pre-Fire Plan FZ 8.6-0 Southeast End, Revision 1; Turbine Bldg. 451"–0" Elevation Unit 1 General Area–SW End
- Pre-Fire Plan FZ 8.6–0 Southeast Center, Revision 3; Turbine Bldg. 451"–0" Elevation Unit 1 General Area–SE Center
- Pre-Fire Plan FZ 8.6–0 Northwest End, Revision 2; Turbine Bldg. 451"–0" Elevation Unit 2 General Area–NW End
- Pre-Fire Plan FZ 8.6–0 Northwest Center, Revision 1; Turbine Bldg. 451"–0" Elevation Unit 2 General Area–NW Center
- Pre-Fire Plan FZ 8.6–0 Northeast End, Revision 1; Turbine Bldg. 451"–0" Elevation Unit 2 General Area–NE End
- Pre-Fire Plan FZ 8.6–0 Northeast Center, Revision 2; Turbine Bldg. 451"–0" Elevation Unit 2 General Area–NE Center
- Pre-Fire Plan FZ 11.6–2, Revision 2; Auxiliary Bldg. 426'0" Elevation Division 22 Electrical Penetration Area

Section 1R06

- UFSAR Section 9.3.3.2, "Auxiliary Building Safety-related Components Area Flood Analysis
- Information Notice 05–30, "Safe Shutdown Potentially Challenged by Unanalyzed Internal Flooding Events and Inadequate Design"
- NUREG–0800, Standard Review Plan 3.6.1, Plan Design for Protection Against Postulated Piping Failures in Fluid Systems Outside Containment

Section 1R07

- WO 1711702; 1VA04SA–HX Inspection per Generic Letter 89–13
- IR 1163845; UT Thickness Results of 2" Piping off 1A SI Pp Cube Cooler
- IR 1164479; 1VA04SA Leaked During Leak Test
- IR 1164943; Tube Plugging Required for 1A SI Pump Cubicle Cooler
- IR 2525637; GL 89–13 Work Not Performed as Scheduled (1VA04SA)
- BVP 800–30, Revision 16; Essential Service Water Fouling Monitoring Program (GL 89–13 Program Basis Document)
- ER–AA–340–1002, Revision 6; Service Water Heat Exchanger Inspection Guide

Section 1R11

- Evaluation scenario for Crew B1 on March 1, 2016
- IR 02627877; "Feedwater NPSH Low" Spurious Alarm
- WO 01904090; "Feedwater NPSH Low" Spurious Alarm
- IR 02636175; HDT [Heater Drain Tank] Level Control Issues

- IR 02641860; Auto Start of Standby CD/CB Pump During Maintenance
- 1BGP 100–4, Revision 54; Power Descension

Section 1R12

- Maintenance Rule Performance Criteria Selection Template for function DC–02
- Performance Summary Evaluations for Function DC–02 (Unit 1 and Unit 2)
- IR 01419867; R2 Loss of Bus 142 Control Power
- IR 01688608; Unexpected Alarm DC Bus 112
- IR 02391804; Lost DC Bus to Crosstie Breaker Tripping Open
- IR 01470860; Unexpected Alarm While Shutting Down DC Bus 211 Battery Charger
- Maintenance Rule Performance Criteria Selection Template for Function PR–02
- Performance Summary Evaluations for Function PR–02 (Unit 1 and Unit 2)
- IR 01635846; 2PR14J Won't Restart
- IR 02431791; 2PR14J Skid Pump Broke
- IR 02559665; Check Source Failed
- IR 02567468; 2PR14J Failed Checksource
- IR 02584129; 2PR14J Checksource Failure
- IR 01652860; 2B CD/CB Pump Tripped
- IR 01653704; Dripping From Pipe Downstream From 2CD041D
- IR 01655158; 2B CD/CB Pump Trip Organizational Learnings
- IR 01660110; U2 CD/CB M-Rule A(1) Determination 1652860 Event
- IR 01667828; Extent of Condition for Unit 2 CD Pipe Leak
- Maintenance Rule System Basis Document for Function AF–07
- ER–AA–310–1002, Revision 3; Maintenance Rule Functions–Safety Significance Classification
- Maintenance Rule System Basis Document for Function PC–02
- 1BEP–3, Revision 209; Steam Generator Tube Rupture, Unit 1
- ER–AA–310–1001, Revision 4; Maintenance Rule–Scoping
- Maintenance Rule System Basis Document for Function AF–01

Section 1R13

- Online Risk Assessment for Week of 01/11/16–E–4
- Online Risk Assessment for Week of 01/11/16–E–4 Rev 1
- Online Risk Assessment for Week of 01/11/16–E–4 Rev 2
- Online Risk Assessment for Week of 01/18/16–E–4
- Online Risk Assessment for Week of 01/18/16–E–4 Rev 1
- Online Risk Assessment for Week of 03/28/16–E–4 Rev 2
- BY–SURV–009, Revision 0; Risk Assessment Deficient Surveillance–AF Suction Swap Over
- IR 02615434; Inadequate Test Methodology For AF Pump Suction Pressure Loops
- EC 386524; Design Change to AF Suction Pressure Logic Unit 1
- WO 1629838; ST–OAP Test MA–773–039 U–1 EC 386524 Major Under Task 85
- EC 386525; Design Change to AF Suction Pressure Logic Unit 2
- Online Risk Assessment for Week of 02/22/16–E–4 Rev 3
- BOP DO–9, Revision 16; Filling a Unit 2 Diesel Generator Storage Tank
- BOP DO–11, Revision 11; Draining a Unit 2 Diesel Generator Fuel Oil Storage Tank
- BOP DO–16, Revision 18; Filling the Unit 2 Diesel Auxiliary Feedwater Pump Day Tank
- 2BOL 8.1, Revision 20; LCOAR AC Sources–Operating Tech Specification LCO # 3.8.1
- IR 02636112; Question on AFW Diesel Air Intake
- IR 02637248; Monitoring AF Diesel Release Path Improvements

- EC 404997, Revision 000; Remove AF Diesel Air Intake Elbow and Blank Off TB Air Intake
- WO 01904882; Install TCCP 404997 on U1 AF Diesel Air Intake
- WO 01904883; Install TCCP 404997 on U2 AF Diesel Air Intake
- Online Risk Assessment for Week of 03/07/16–E–4 Rev 2
- Online Risk Assessment for Week of 03/07/16–E–4 Rev 3
- Online Risk Assessment for Week of 03/07/16–E–4 Rev 4

Section 1R15

- IR 02620162; Results of GL 89–13 As-Found (0WO01CA)
- EC 346998, Revision 0; Evaluate Min Wall Criteria and Gasket Mating Surface Requirements for MCR Chillers
- EC 351138, Revision 0; Design Considerations Summary (for MCR Chillers/Chiller condensers)
- IR 02623828; Lining Degradation Identified in 2A DOST
- EC 334126, Revision1; Evaluation of Degraded Coating on 2B Diesel Oil Storage Tank EPN No. 2DO01TB
- IR 02631377; FP [Fire Protection] 6 Inch Small through Wall Leak AB [Auxiliary Building] 346 L19
- EC Evaluation 404949, Rev 000; Functionality Eval for Through Wall Leak on OFP3A-6” per N–513–3
- IR 02634348; NDE–Examine 0FPC5A–6” to Support N–513 Required Inspections
- IR 02634352; NDE–Examine 0FPC2BC–6” to Support N–513 Required Inspections
- IR 02634355; NDE–Examine 0FPD8A–6” to Support N–513 Required Inspections
- IR 02634359; NDE–Examine 0FPE4A–6” to Support N–513 Required Inspections
- IR 02632362; NDE–Examine 0FPC2BA–6” to Support N–513 Required Inspections
- EC 380016, Revision 004; U–1 Steam Generator Margin to Overfill (SG MTO) Air Accumulator for 1AF005A thru H
- WO 1719737; Calibrate Electronic Portion of AF Loop
- BISR 3.4.2–200, Revision 13; Surveillance Calibration of Aux Feedwater to Steam Generators A, B, C and D Flow Control Loops
- IR 02607148; Procedure Discrepancy on Failing IA to AF005 Valves
- IR 02608461; Ops Focus AF005 Design Change
- IR 02528826; Ops Focus-OLR Component Impact Not Addressed by Surveillance
- M-37, Revision BE; Diagram of Auxiliary Feedwater
- OP–BY–102–106, Revision 8; Operator Response Time Program at Byron Station
- 1BEP–0, Revision 207; Reactor Trip or Safety Injection Unit 1
- 1BEP–0, Revision 203; Reactor Trip or Safety Injection Unit 1
- 1BEP–3, Revision 209; Steam Generator Tube Rupture Unit 1
- 1BEP–3, Revision 207; Steam Generator Tube Rupture Unit 1
- IR 01416822; MTO Mod Test–Flow Control Valves Did Not Reach Full Closed
- IR 00522363; CDBI FASA–SGTR Analysis Non-Bounding Assumption
- Braidwood/Byron Stations MUR LAR Response to RAI; February 20, 2012
- EC 379685, Revision 0; SGTR Design Analyses and Licensing Basis Changes
- BYR10–127, Revision 004; Byron/Braidwood Steam Generator Tube Rupture Margin to Overfill Single Failure Assessment
- IR 2647059; 1B CS Pp MCB C/S No Light Indication
- 6E–1–4030CS02, Revision W; Schematic Diagram Containment Spray Pump 1B
- 6E–1–4054K, Revision AB; Internal/External Wiring Diagram MCB Eng Safety Features Section A1–Part 10
- 6E–1–4613H, Revision P; Internal/External Wiring Diagram 4160V ESF SWGR Bus 142 Cub.8

- 6E–1–4054A, Revision AH; Internal/External Wiring Diagram MCB Eng Safety Features Section A1–Part 1
- WO 1911828; 1B CS Pp MCB C/S No Light Indication
- BOP AP–32, Revision 3; Synchronizing a SAT to a Bus Being Fed by a DG
- M–152, Sheet 15, Revision S; Mfr's Supplement Diagram of Diesel Generator Control Diagram Shutdown System
- 6E–1–4030DG31, Revision AO; Schematic Diagram Diesel Generator 1A Starting Sequence Control 1DG01KA, Part–1
- IR 2612025; 2A DG Trip: E.O./NSO Insights and Concerns
- IR 2612060; Ops Focus–Review Extent of Condition DG Non-Emergency Trip
- IR 2611695; 2A D/G Trip When Performing 2BOSR 8.1.2–1
- IR 2570788; 2A DG Trip During Test Mode Start

<u>Section 1R18</u>

- IR 02636112; Question on AFW Diesel Air Intake
- IR 02637248; Monitoring AF Diesel Release Path Improvements
- EC 404997, Revision 000; Remove AF Diesel Air Intake Elbow and Blank Off TB Air Intake
- WO 01904882; Install TCCP 404997 on U1 AF Diesel Air Intake
- WO 01904883; Install TCCP 404997 on U2 AF Diesel Air Intake
- TCCP 404997, Revision 0; 50.59 Screening (6E–16–027) and 50.59 Evaluation (6G–16–001)

<u>Section 1R19</u>

- IR 02613455; 1FW009C Lowering Hydraulic Pressure
- IR 02613634; Fuse Replaced on 1FW009C
- IR 02613510; Ops Focus: 4.0 Critique of 1FW009C Event
- WO 01869647; 1FW009C Pump Light Cycling For 1FW009C Every 19 Seconds
- WO 1756339; Replace Pneumatic/Control Valves
- WO 1886566; LR–2A Diesel Generator Operability Surveillance
- 2BOSR 8.1.2–1, Revision 33; Unit Two 2A Diesel Generator Operability Surveillance
- BOP DG–11T1, Revision 3; Diesel Generator Start/Stop Log
- BOP DG–11T2, Revision 17; Diesel Generator Operating Log
- M–54, Sheet 4B, Revision G; Diagram of Service Air (Diesel Generator Starting Air)
- M–152, Sheet 15, Revision S; Manufacturer's Supplement Diagram of Diesel Generator Control Diagram Shutdown System
- M–152, Sheet 20, Revision H; Control Diagram Starting System and Alarms
- MA–AA–716–012, Revision 20; Post Maintenance Testing
- BOP DG–13, Revision 2; Trouble-Shooting Diesel Generators
- BOP DG–13T1, Revision 6; Diesel Generator Troubleshooting Checklist, Checklist A
- IR 02611695; 2A DG Trip When Performing 2BOSR 8.1.2–1
- IR 02625454; 2A DG Maintenance Run Manual Trip
- IR 02625778; Diesel Surging in Cool Down Cycle
- IR 02626757; FM [Foreign Material] Identified During Work
- IR 02627044; Critique of the 2A DG and DOST Window 2–8–16 Execution Week
- IR 02627474; Possible Stuck Lifter on 8L Cylinder of 2A DG
- IR 02628165; Aggregate Review of 2A DG Window for Maintenance
- IR 02629299; Fuel Line Support Bracket Loose-Fitting
- WO 1899167; Leak From Compression Fitting on the Suction of the Fuel Oil Pump
- ECR 422455; New Support Bracket for 2A DG Fuel Line
- IR 02629950; 2A DG Found Damaged Lifter, Snap Ring on 8L Exhaust

- WO 1900504; Possible Stuck Lifter on 8L Cylinder of 2A DG
- IR 02625778; Diesel Surging in Cool Down Cycle
- WO 01869647; 1FW009C Pump Light Cycling for 1FW009C Every 19 Seconds
- WO 1874944; LR–1AF01AB–Hx Inspection per Generic Letter 89–13
- WO 1903586; 1B AF Pump Surveillance
- 1BOSR 7.5.4–2, Revision 21; Unit One Diesel Driven Auxiliary Feedwater Pump Monthly Surveillance

Section 1R22

- WO 1814072; U1 Train A AF Valves Indication Test
- WO 1719532; U1 Train B AF Valves Indication Test
- WO 1875885; STT for 1AF017B and 1AF006B (Week H)
- 1BOSR 0.5–2.AF.3–1, Revision 11; Unit One Auxiliary Feedwater Valves Train A Indication Test
- 1BOSR 0.5–2.AF.3–2, Revision 13; Unit One Auxiliary Feedwater Valves Train B Indication Test
- 1BOSR 0.5–3.AF.1–2, Revision 13; Unit One ASME Surveillance Requirements for the B Train Auxiliary Feedwater SX Supply Valves
- 1BOSR 0.5–3.AF.1–2.BY01, Revision 1; Acceptance Criteria Data Sheet
- M–37, Revision BE; Diagram of Auxiliary Feedwater
- IR 2618096; Place Keeping Error Identified on Procedure Review
- IR 2615434; Inadequate Test Methodology for AF Pp Suction Press Loops
- IR 2617496; DSA 2AF–055 COT Not Performed
- IR 2617530; Work Instructions Improvement for Functional Test
- 1BOL 3.2, Revision 10; LCOAR Engineered Safety Feature Actuation System (ESFAS) Instrumentation Tech Spec LCO # 3.3.2
- WO 1889376; Functional Test of Aux Feedwater Pump Suction Pressure
- WO 1888056; Functional Test of Aux Feedwater Pump Suction Pressure
- WO 1891921; Functional Test of Aux Feedwater Pump Suction Pressure
- WO 1890755; Functional Test of Aux Feedwater Pump Suction Pressure
- 1BSIR 3.2.2–001, Revision 12; Channel Operation Test of Train A Auxiliary Feedwater Pump Suction Pressure Loop
- 1BISR 3.2.2–002, Revision 11; Channel Operation Test of Train B Auxiliary Feedwater Pump Suction Pressure Loop
- 2BISR 3.2.2–001, Revision 12; Channel Operation Test of Train A Auxiliary Feedwater Pump Suction Pressure Loop
- 2BISR 3.2.2–002, Revision 11; Channel Operation Test of Train B Auxiliary Feedwater Pump Suction Pressure Loop
- 6E–1–4031AF13, Revision E; Loop Schematic Diagram Auxiliary Feedwater Pump Suction Pressure Cab. 1PA33J
- WO 01886550; Slave Relay Train A CS–K644/CS
- 1BOSR 3.2.8–644A, Revision 3; Unit One ESFAS Instrument Slave Relay Surveillance (Train A Automatic Containment Spray–K644)

Section 1EP6

- Byron 2016 1Q Drill Scenario

Section 4OA1

- IR 02481584; Need to Submit FAQ for December 2014 Downpower

Section 4OA2

- Emails between Exelon and Cummins NPower; Subject: Battery Box Heater in Service document.docx; September 3, 2015, through September 4, 2015
- SM–AA–102, Revision 21; Warehouse Operations
- PI–AA–115–1004, Revision 2; Processing of NERs, ICES OEs, and Root Cause Report Transmittals
- PI–AA–115, Revision 0; Operating Experience Program
- IR 02596123; FLEX Batt Heater Thermostat Inspection Results
- IR 02547347; FLEX EDG, Found Battery Damaged from Heat
- IR 02586476; All Flex Diesel Generators Need Battery Replacement
- IR 02582798; 0FX01KC Is Dead Control Panel Dark
- IR 02583342; 0FX01KA Batteries Degraded But Functional
- IR 02583346; 0FX01KB Batteries Degraded But Functional
- IR 02583377; Overheated Heat Trace on Flex Emergency Diesel Generator
- IR 02587992; Heat Trace on 0FX01KA Battery Compartment Found Wired Incorrectly
- Letter from P. Hoogervorst, Cummins NPower, to S. Mokkapati, Exelon; Subject: Battery Heaters–FLEX Diesel Generators; November 19, 2015
- Memo from P. Hoogervorst, Cummins NPower; Subject: Operational Dependence Statement regarding Battery Box Heaters; September 4, 2015
- IR 02587994; Heat Trace on 0FX01KB Battery Compartment Found Wired Incorrectly
- IR 02587996; Heat Trace on 0FX01KC Battery Compartment Found Wired Incorrectly
- IR 02586497; 0BOL FX1 Needs Clarification
- IR 02630402; Cyber Security Network Switch Model Correction
- IR 02632162; Cyber Security NRC Observation Topic “BADUSB” Potential Vulnerability
- IR 02632379; Cyber Security NRC Observation Topic MD5 Hash Code Use
- IR 02632384; Cyber Security NRC Observation Topic Insufficient Documentation
- IR 02633315; Cyber Security NRC Observation Topic Kiosk Protection; February 29, 2016
- IR 01507225; Cyber Security Braidwood LL; MS 4 Issues With Virus Scanning Kiosk
- IR 01522300; Cyber Security Reevaluation Of EPT Network Boundary Devices
- IR 01522309; Cyber Security; Scoping of Physical Security Digital Assets
- IR 01585211; Cyber Security; NRC Green NCV–Components in TSC
- IR 01585215; Cyber Security; NRC Green NCV–Deterministic Protective Devices
- IR 02588100; Licensee Identified NCV: Failed to Enforce Mobile Device Security and Int
- IR 02588102; Tracking Resolution of NCVS
- IR 01579169; Kiosk Compliance–Hardening and System Security
- IR 01579162; Kiosk Compliance–Hardening Requirements
- IR 01549909; Ensure Kiosks Comply to NRC Good Faith Letter Dated 7/1/2013
- PI–AA–120, Revision 3; Issue Identification and Screening Process
- PI–AA–125, Revision 2; Corrective Action Program (CAP) Procedure
- MA–AA–716–235, Revision 4; Control of CDA Portable Media and Portable Devices
- IT–AA–235–1003–F–01, Revision 2; OPSWAT Kiosk Configuration and Hardening Checklist
- IT–AA–235–1003–F–02, Revision 2; OPSWAT Kiosk Anti-Virus (AV) Software Install Checklist
- IT–AA–235–1003–F–04, Revision 2; OPSWAT Kiosk Anti-Virus (AV) Definitions Update and Logs Review Checklist
- CC–AA–601, Revision 5; Cyber Security Asset Identification and Assessment Per Requirements of 10 CFR 73.54
- CC–AA–603, Revision 2; Nuclear Cyber Security Defensive Architecture Per Requirements of 10 CFR 73.54
- IT–AA–235–1003, Revision 2; Kiosk Management and Configuration Control

Section 4OA3

- IR 2623652; NRC Identified Issue with Procedure Rev
- BISR 3.1.10–212, Revision 15; Calibration of Digital Electro-Hydraulic (DEH) Servo Controls and Main Turbine Throttle Valves
- BISR 3.1.10–212, Revision 16; Calibration of Digital Electro-Hydraulic (DEH) Servo Controls and Main Turbine Throttle Valves
- ACE 2563847; Mode 3 Entered with K640 Relay Leads Lifted
- WO 1724423; Unit 1 Testing of the Overspeed Trip Network #1
- 6E–1–4030TG04, Revision T; Schematic Diagram Turbine Generator Trip Part 2
- WO 1726331; EF Valve Stroke Time Response Test (Turb Throttle Vls)
- AD–AA–101–1002, Revision 17; Writer's Guide for Procedures and T&RM
- WO 1724422; Unit 1 Testing of the Overspeed Trip Network #2
- WO 1724425; Unit 1 Test of the Overspeed Trip Network #3
- WO 1723795; DEH Throttle Vlvs 1MS5005A, 1MS5005B, 1MS5005C, 1MS5005D
- WO 1726613; DEH Governor Vlvs 1MS5006A, 1MS5006B, 1MS5006C, 1MS5006D
- BIP 2500–143, Revision 17; Calibration of Digital Electro-Hydraulic (DEH) Servo Controls and Main Turbine Governor Valves
- 1BOSR 3.2.8–640A, Revision 4; Unit One ESFAS Instrumentation Relay Surveillance (Train A Turbine Trip–K640)
- HU–AA–104–101, Revision 5; Procedure Use and Adherence
- BAP 1310–10, Revision 17; HU–AA–104–101, Procedure Use and Adherence, Byron Addendum
- 1BGP 100–1T3, Revision 19; Mode 4 to 3 Checklist
- EST 146623; K640 Relay Leads Are Lifted; September 30, 2015
- IR 2563606; B1R20 Critical Path Delay of 3 Hours Due to Work Execution
- BISR 3.1.10–212, Revision 10; Calibration of Digital Electro-Hydraulic (DEH) Servo Controls and Main Turbine Throttle Valves
- IR 2563847; Mode 3 Entered with K640 Relay Leads Lifted
- BY–MODE–011, Revision 7; TS 3.0.4.b Evaluation–Entry to Modes 4, 3, 2, and 1 with 1PR11J, 1MS018C, 1AF01PB, Turbine Overspeed Protection Inoperable

Section 4OA5

- TID–14844; Calculation of Distance Factors for Power and Test Reactor Sites; March 23, 1962
- Branch Technical Position ASB–9–2, Residual Decay Energy for Light-Water Reactors for Long-Term Cooling; Revision 2
- Technical Requirements Manual (TRM) Change 10–008, 1/2 BOSR9.a.1–1, 1/2BVSR 9.a.1–2, 1/2BOL 9.a; TRM Change 10–008, RM Section 3.9a, Decay Change; March 8, 2011
- AR 1561006; The Higher Burnups Due to MUR Requires 1BOSR 9.a to be Revised Back to Original 100 Hours between Shutdown and Start of Refueling; September 19, 2013
- DRP 11–075; Update UFSAR to Reflect the Implementation of Alternate Source Term (AST) and Approved Technical Specification Amendment No. 147 and 140 for Byron and Braidwood Respectively, January 7, 2007
- Byron Station Units 1 and 2, Braidwood Station, Units 1 and 2–Issuance of Amendments RE: Alternate Source Term (TAC Nos. MC6221, MC622, MC223, and MC6224); September 6, 2008
- Regulatory Guide 1.187; Guidance for Implementation of 10 CFR50.59, Changes, Tests, and Experiments; November 2000
- NEI 96–07, Guidelines for 10 CFR 50.59 Evaluations; Revision 1

- Regulatory Guide 1.25; Assumptions Used for Evaluating the Potential Radiological Consequences of a Fuel Handling Accident in the Fuel Handling Building and Storage Facility for Boiling Water and Pressurized Water Reactors; March 1972
- Regulatory Guide 1.183; Alternative Radiological Source Terms for Evaluating Design Basis Accidents at Nuclear Power Reactors; July 2000
- Design Analysis No. BB–FH–18; Dose Rates Due to Fuel Handling Accident; September 15, 2015

LIST OF ACRONYMS USED

∆CDF	Delta Core Damage Frequency
ADAMS	Agencywide Documents Access Management System
AC	Alternating Current
AF	Auxiliary Feedwater System
ASME	American Society of Mechanical Engineers
AST	Alternate Source Term
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CS	Containment Spray
CSP	Cyber Security Plan
DC	Direct Current
DG	Diesel Generator
DOST	Diesel Oil Storage Tank
DRP	Division of Reactor Projects
ECCS	Emergency Core Cooling System
ESF	Engineered Safeguards Feature
ESFAS	Engineered Safety Feature Actuation System
HEP	Human Error Probability
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	Inspection Report
IR	Issue Report
IST	Inservice Testing
LER	Licensee Event Report
LCO	Limiting Condition for Operation
MS	Milestone
MSIV	Main Steam Isolation Valve
NCV	Non-Cited Violation
NEI	Nuclear Energy Institute
NPP	Nuclear Power Plant
NRC	U.S. Nuclear Regulatory Commission
PI	Performance Indicator
PI&R	Problem Identification and Resolution
PM	Post Maintenance
PSF	Performance Shaping Factor
SIF	Security Issues Forum
SPAR	Standardize Plant Analysis Risk
SRA	Senior Reactor Analyst
SSC	Structure System or Component
SSPS	Solid State Protection System
SX	Service Water
TCCP	Temporary Configuration Change Package
TI	Temporary Instruction
TRM	Technical Requirements Manual
TS	Technical Specification
TSO	Transmission System Operator
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WO	Work Order

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Sincerely,

/RA/

Eric R. Duncan, Chief
Branch 3
Division of Reactor Projects

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