UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION III
2443 WARRENVILLE RD. SUITE 210
LISLE, IL 60532-4352

September 18, 2015

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 PROBLEM IDENTIFICATION AND RESOLUTION INSPECTION REPORT 05000454/2015007; 05000455/20150007 AND NOTICE OF VIOLATION

Dear Mr. Hanson:

On August 7, 2015, the U.S. Nuclear Regulatory Commission (NRC) completed a Problem Identification and Resolution (PI&R) inspection at your Byron Station, Units 1 and 2. The enclosed report documents the inspection results, which were discussed on August 11, 2015, with Mr. T. Chalmers and other members of your staff. The inspection team documented the results of this inspection in the enclosed inspection report.

The inspection examined activities conducted under your licensee as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

On the basis of the samples selected for review, the team concluded that, overall, the Corrective Action Program (CAP) at Byron Station was adequate in identifying, evaluating, and correcting issues with varying degrees of effectiveness. The licensee had a low threshold for identifying issues and entering them into the CAP. Issues entered into the CAP were prioritized and evaluated based on plant risk and uncertainty. Corrective actions were generally implemented in a timely manner, commensurate with their safety significance. Operating Experience (OE) was entered into the CAP and appropriately evaluated. The use of OE was integrated into daily activities and found to be effective in preventing similar issues at the plant. In addition, self-assessments, audits, and effectiveness reviews were found to be conducted at appropriate frequencies with sufficient depth for all departments. The assessments reviewed were thorough and effective in identifying site performance deficiencies, programmatic concerns, and improvement opportunities. On the basis of the interviews conducted, the inspectors did not identify any impediment to the establishment of a healthy Safety-Conscious Work Environment at Byron Station. Licensee staff were aware of and generally familiar with the CAP and other station processes, including the Employee Concerns Program, through which concerns could be raised.

Although implementation of the CAP was determined to be adequate, overall, based on the samples reviewed, three findings of very low safety significance (Green) were identified during the inspection. Additionally, one Unresolved Item was identified and is discussed in Section 4OA5 of this report. These findings were determined to involve violations of NRC requirements. Since two of the findings were of very low safety significance and were entered into the CAP, the NRC is treating these violations as non-cited violations (NCVs) in accordance with Section 2.3.2 of the NRC Enforcement Policy. The remaining violation, however, is cited in the enclosed Notice of Violation (Notice) and the circumstances surrounding this violation are described in detail in the enclosed report. Although determined to be of very low safety significance (Green), in accordance with Section 2.3.2 of the NRC Enforcement Policy, this violation is being cited because you have failed to restore compliance within a reasonable time after the violation was identified in NRC Inspection Report 05000454/2008009; 05000455/2008009 and again in NRC Inspection Report 05000454/2011008; 05000255/2008011. The NRC Enforcement Policy is included on the NRC's Web site at (http:www.nrc.gov/about-nrc/regulatory/enforcement/enforce-pol-html).

You are required to respond to this letter and should follow the instructions specified in the enclosed Notice when preparing your response. If you have additional information that you believe the NRC should consider, you may provide it in your response to the Notice. The NRC will use your response, in part, to determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

If you contest the violations or significance of these NCVs, 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 a copy to the Regional Administrator, U.S. Nuclear Regulatory Commission–Region III, 2443 Warrenville Road, Suite 210, Lisle, IL 60532–4352; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; and the Resident Inspector Office at the Byron Station. In addition, if you disagree with the cross-cutting aspect assigned to any 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 enclosures, 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 (PARS) 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 Duncan, Chief
Branch 3
Division of Reactor Projects

Docket Nos. 50-454, 50-455
License Nos. NPF-37, NPF-66

Enclosure:
1. Notice of Violation
2. Inspection Report 05000454/2015007;
   05000455/2015007
   w/Attachment:
   Supplemental Information

cc w/encl: Distribution via ListServ®

NOTICE OF VIOLATION

Exelon Generation Company, LLC | Docket Nos. 50-454, 50-455
Byron Station | License Nos. NPF-37, NPF-77

During an NRC inspection conducted on July 20 through August 7, 2015, a violation of NRC requirements was identified. In accordance with the NRC Enforcement Policy, the violation is listed below:

> Title 10 CFR Part 50, Appendix B, Criterion III, "Design Control," requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis for structures, systems, and components, are correctly translated into specifications, drawings, procedures, and instructions, and that design control measures shall provide for verifying or checking the adequacy of the design.
>
> Contrary to the above, from initial plant construction until August 11, 2015, the licensee failed to verify the adequacy of the design of the Byron Unit 1 and Unit 2 recycle holdup tanks, which are safety-related components subject to the requirements of Title 10 CFR Part 50, Appendix B, Criterion III. Specifically, the licensee failed to evaluate the effect of dynamic loads on inlet piping from the Unit 1 and Unit 2 residual heat removal systems' suction relief valves that discharge to the recycle holdup tanks; and, as a result, failed to verify the adequacy of the recycle holdup tank design to withstand design loads that would result from a discharge of residual heat removal system relief valves into the recycle holdup tanks.

This violation is associated with a Green Significance Determination Process finding.

Pursuant to the provisions of 10 CFR 2.201, Exelon Generation Company, LLC is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001 with a copy to the Regional Administrator, Region III, and a copy to the NRC Resident Inspector at the Byron Station, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a "Reply to a Notice of Violation; IR 05000454/2015007; 05000455/2015007" and should include for each violation: (1) the reason for the violation, or, if contested, the basis for disputing the violation, (2) the corrective steps that have been taken and the results achieved, (3) the corrective steps that will be taken, and (4) the date when full compliance will be achieved. Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an Order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington DC 20555-0001.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). In accordance with 10 CFR 19.11, you may be required to post this Notice within 2 working days of receipt.

Dated this 18th day of September 2015

U. S. NUCLEAR REGULATORY COMMISSION

REGION III

Docket Nos:	50-454; 50-455
License Nos:	NPF-37; NPF-66
Report No:	05000454/2015007; 05000455/2015007
Licensee:	Exelon Generation Company, LLC
Facility:	Byron Station, Units 1 and 2
Location:	Byron, IL
Dates:	July 20 through August 7, 2015
Inspectors:	J. Benjamin, Team Leader B. Palagi, Senior Operations Engineer J. Draper, Resident Inspector - Byron V. Meghani, Reactor Inspector C. Thompson, Resident Inspector, Illinois Emergency Management Agency
Approved by:	E. Duncan, Chief Branch 3 Division of Reactor Projects

SUMMARY OF FINDINGS

Inspection Report 05000454/2015007 and 05000455/2015007; 07/202015 - 08/07/2015; Byron Station, Units 1 & 2; Identification and Resolution of Problems.

This team inspection was performed by two regional inspectors, the Byron Resident Inspector, and the Braidwood Senior Resident Inspector. Three findings of very low safety significance were identified by the inspectors. Two of the findings were considered non-cited violations (NCVs) of U.S. Nuclear Regulatory Commission (NRC) regulations. One of the findings was considered a cited violation (VIO) of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 5, dated February 2014.

Problem Identification and Resolution

On the basis of the samples selected for review, the inspection team concluded that the CAP at Byron Station was generally being implemented in an effective manner. Licensee personnel had a low threshold for identifying problems and entering them into the CAP. Issues entered into the CAP were consistently found to be screened and prioritized in a timely manner commensurate with the safety significance of the issues and in accordance with program guidance and requirements. The team identified that the staff's review of operating experience (OE) for applicability to station design and activities was generally effective. Audits and self-assessments were generally thorough and intrusive and performed at an appropriate level to identify deficiencies. Based on the interviews conducted during the inspection, the inspectors did not identify any impediment to the establishment of a healthy Safety-Conscious Work Environment at Byron Station. Specifically, employees at the site expressed a willingness to raise concerns related to nuclear safety without the fear of retaliation. Additionally, workers were aware of and generally familiar with the CAP process and other processes, including the Employee Concerns Program (ECP), which could be used as a means to raise safety concerns.

Cornerstone: Mitigating Systems

- Green. A finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was self-revealed when the licensee failed to adequately consider the potential impact that a modification would have on the safety-related emergency diesel generator (DG) fuel oil supply credited for design basis events. Specifically, the DG fuel oil system was modified in a manner that reduced the DG fuel oil system train separation from two isolation valves to one isolation valve. The adverse impact of a leaking single isolation valve following the implementation of a diverse and flexible coping capability (FLEX) modification resulted in the 1B DG fuel oil transfer pump(s) pumping fuel oil not only into its associated 1B DG fuel oil day tank but also into the 1A DG diesel oil storage tank (DOST). The safety-related 1B DG fuel oil system was categorized as a low margin system, and the inspectors identified that the licensee did not adequately follow the considerations provided in the design change process for a low margin system. In addition to entering this issue into their CAP, immediate corrective actions included restoring the fuel oil configuration to the previous dual isolation configuration until long-term corrective actions could be developed.

The inspectors determined that the performance deficiency was more than minor because it was associated with the Mitigating Systems cornerstone attribute of Design Control and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding was of very low safety significance (Green) because the issue did not prevent the 1B DG from being able to operate for its mission time. The finding had a cross-cutting aspect in the Avoid Complacency component of the Human Performance cross-cutting area because the licensee failed to recognize that the configuration change resulted in the licensee operating the DG fuel oil system in a configuration that it had not routinely operated in, exposing previously unidentified deficiencies (H.12). (Section 4OA2.1)

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings", when the licensee failed to adequately evaluate an issue entered into the CAP for operability and associated reportability. Specifically, the licensee failed to evaluate operability and reportability after DG fuel oil was identified to be unexpectedly overflowing into an "A train" DOST when a "B train" DG fuel oil transfer pump was operating. The licensee did not readily recognize that this issue impacted the mission time of the 1B DG system due to fuel oil leaving the associated fuel oil train. In addition to entering this issue into their CAP, corrective actions included a review of past operability and submitting a Licensee Event Report (LER).

  The inspectors determined that the performance deficiency was more than minor, because it was associated with the Mitigating Systems cornerstone attribute of Design Control and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The finding was of very low safety significance (Green) because the issue did not impact the operability of the DG for more than its Technical Specification (TS) allowed outage time (AOT). The finding had a cross-cutting aspect in the Teamwork component of the Human Performance cross-cutting area because individuals within the Operations department, as well as other workgroups within the licensee's organization, failed to communicate to ensure the safety impact of the leaking valve was adequately understood (H.4). (Section 4OA2.1)

- Green. The inspectors identified a finding of very low safety significance (Green) and an associated VIO of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to evaluate the effect of dynamic loads on inlet piping from Unit 1 and Unit 2 residual heat removal (RHR) suction relief valves that discharged to the recycle holdup tank (RHUT). The NRC previously issued two NCVs regarding this issue and corrective actions to date have been incomplete. In addition to entering this issue into their CAP, planned corrective actions included the installation of approximately 20 pipe supports.

  The inspectors determined that the performance deficiency was more than minor, because it was associated with the Barrier Integrity Cornerstone attribute of Design Control and adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the licensee's existing design and piping configuration had not addressed water hammer effects when the Unit 1 and Unit 2 RHR suction relief valves were aligned to discharge to the RHUT. A ruptured RHUT and/or associated piping outside of containment could adversely affect on-site and offsite dose consequences. An NRC Senior

Reactor Analyst (SRA) performed a detailed risk evaluation and determined that the finding was of very low safety significance (i.e., Green). The finding had a cross-cutting aspect in the Resources component of the Human Performance cross-cutting area because leaders at the station did not ensure that personnel, equipment, procedures, and other necessary resources were available and adequate to correct the condition adverse to quality (H.1). (Section 4OA2.3)

REPORT DETAILS

4. OTHER ACTIVITIES

4OA2 Problem Identification and Resolution (71152B)

The activities documented in Sections .1 through .4 constituted one biennial sample of Problem Identification and Resolution (PI&R) as defined in Inspection Procedure 71152.

.1 Assessment of Corrective Action Program Effectiveness

a. Inspection Scope

The inspectors reviewed the licensee's Corrective Action Program (CAP) implementing procedures, interviewed licensee personnel, and attended selected CAP meetings to assess the implementation of the CAP by site personnel.

The inspectors reviewed risk-significant and safety-significant issues entered into the licensee's CAP since the last NRC biennial PI&R inspection in November 2013. The items selected ensured an adequate review of issues across the NRC cornerstones. The inspectors used issues identified through NRC generic communications, department self-assessments, licensee audits, OE reports, and NRC-documented findings as sources to select issues. Additionally, the inspectors reviewed CAP items generated as a result of facility personnel performance in daily plant activities. The inspectors also reviewed CAP items and a selection of completed investigations from the licensee's various investigation methods, including root cause evaluations, apparent cause evaluations (ACEs), and common cause evaluations.

The inspectors performed a more extensive review of the auxiliary feed water system and area and process radiation monitors. This review included a 5-year search of related issues identified in the CAP and discussions with licensee staff to assess the licensee's efforts in addressing identified concerns.

The inspectors attended meetings of the Station Oversight Committee (SOC) and Management Review Committee (MRC) to observe how issues were screened and evaluated, and to obtain insights into the licensee's oversight of the CAP. The inspectors also interviewed members of the licensee's staff.

During the reviews, the inspectors evaluated whether the licensee's actions were in compliance with the facility's CAP and 10 CFR Part 50, Appendix B requirements. Specifically, the inspectors evaluated if licensee personnel were identifying plant issues at the proper threshold, entering the plant issues into the station's CAP in a timely manner, and assigning the appropriate prioritization for resolution of the issues. The inspectors also assessed whether the licensee staff assigned the appropriate investigation method to ensure the proper determination of root, apparent, and contributing causes. The inspectors also reviewed the timeliness and effectiveness of corrective actions for selected issue reports (IRs); completed investigations; and NRC findings, including NCVs.

b. Assessment

(1) Effectiveness of Problem Identification

The inspectors concluded that issues were generally and consistently being identified at a low threshold, evaluated appropriately, and corrected through CAP action assignments. Workers interviewed were familiar with the CAP and were willing to enter issues into the CAP. This was evident by the large number of CAP items generated annually; which were reasonably distributed across the various departments. Additionally, the inspectors determined that OE applicable to the station was generally being entered and processed through the CAP.

The inspectors determined that the station was generally effective at trending low level issues to prevent larger issues from developing. A review of specific trend evaluations did not identify any concerns.

Findings

No findings were identified.

(2) Effectiveness of Prioritization and Evaluation of Issues

The inspectors determined that identified issues were generally prioritized and evaluated commensurate with their risk significance in accordance with procedural requirements. Higher level evaluations such as root cause and ACEs were generally technically accurate, of sufficient depth to effectively identify the cause(s) of the issues; and adequately considered extent of condition, extent of cause, generic implications, and previous occurrences.

The inspectors concluded that the SOC and MRC meetings were generally thorough and effective. Meeting participants were observed to be well prepared for the meetings and actively engaged. The inspectors observed numerous SOC and MRC meetings effectively screen and prioritize issues, assign department ownership, and utilize other quality programs such as the work control program to track assigned tasks for issue closure.

The inspectors concluded that overall, Byron Station generally effectively evaluated equipment operability or functionality after a non-conforming issue or equipment degradation was identified. The inspectors identified that NRC reportability requirements were generally met. The inspectors, however, did identify one example in which the licensee failed to adequately consider equipment operability and NRC reportability requirements after entering an issue into the CAP.

Findings and Observations

Observation: Unplanned Orange Risk Conditions Due to Severe Weather Occurring While an Emergency Diesel Generator was Out-of-Service for Maintenance

The on-line and shutdown risk program at Byron employs a color-coded system to reflect core damage probability based upon equipment availability and initiating event likelihood. Assigned risk colors increase from Green (lowest risk), to Yellow, then

Orange, and finally Red (highest risk). The licensee utilizes the on-line and shutdown risk program to assess plant risk both proactively, based on a planned schedule, as well as reactively, based upon emergent equipment issues and weather conditions. Entry into a planned Red risk condition is prohibited by station procedures. Entry into a planned Orange risk condition, although permitted, is generally avoided or minimized, and requires management approval and increased station oversight.

The inspectors performed a 5 year review of all unplanned Orange plant risk conditions to determine if the licensee had appropriately implemented the on-line and shutdown risk program to minimize Orange risk conditions.

The inspectors identified two instances of unplanned Orange risk that shared the common theme of occurring during severe weather with a DG out-of-service for planned maintenance. Specifically, on October 26, 2010, a severe thunderstorm warning was issued while the 1B DG was unavailable; and then, more recently, on May 20, 2014, a severe thunderstorm warning was issued while the 2B DG was unavailable. Although these unplanned Orange risk conditions were entered into the CAP, the licensee did not perform any level of causal evaluation, nor did the CAP assign any action to preclude or limit similar events in the future.

The inspectors reviewed internal OE and identified that Braidwood, which is very similar in design and located near Byron, had two similar unplanned Orange risk conditions within the past 5 years. Specifically, on March 6, 2012, a high wind warning was issued while the 2A DG was unavailable; and on May 8, 2015, a severe thunderstorm warning was issued while the 1A DG was unavailable. Similar to Byron, the inspectors determined that although these unplanned Orange risk conditions were entered into the CAP, Braidwood had not performed a causal evaluation or assign any action through the CAP to preclude or limit similar events in the future.

The inspectors reviewed station CAP procedures, OE procedures, and licensee risk assessments required by 10 CFR 50.65a(4) and determined that although no formal evaluation had been performed through the CAP, the licensee scheduled future DG on-line work when severe weather had not historically occurred. As a result, no findings were identified.

Although no findings were identified, the inspectors questioned the licensee's decision to not utilize the CAP to perform formal causal evaluations for the unplanned Orange risk conditions and determine if corrective actions could be implemented to improve nuclear safety during planned on-line DG work. The licensee entered this observation into their CAP is IR 2540347.

Failure to Evaluate the Impact of a FLEX-Related Configuration Change on Available Diesel Generator Fuel Oil Margin

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings", was identified when the licensee failed to adequately consider the potential impact that a modification associated with a FLEX strategy would have on the safety-related DG fuel oil supply credited for design basis events.

Description: On October 4, 2014, Engineering Change (EC) 398031 was approved to add the ability to refill the diesel-driven auxiliary feedwater day tank during a beyond design basis event. Included in this design modification was a change to the position of the recirculation isolation valves for the 1B and 2B DG fuel oil transfer pumps, 1DO055B and 2DO2055B respectively, from normally closed to normally open.

In the open position, these valves establish a flow path from the DOST fuel oil transfer pump discharge to the diesel-driven auxiliary feedwater pump day tank. However, this modification also reduced DG fuel oil train separation from dual to single valve isolation when the DGs were aligned for normal standby operation.

Prior to the design change, when 1DO055B and 2DO055B were closed, procedures only directed the valves to be opened when draining the DOSTs. Therefore, these valves were closed when their respective DG fuel oil transfer pumps were operating, such as during DG surveillance testing. Additionally, the DOST fill procedures were written such that the fill header was left drained when the tanks were not being filled. As a result, the only instances in which isolation valves associated with DOST piping were subject to the discharge pressure of the diesel oil transfer pumps were during draining of the DOSTs. One instance when this activity occurred was on May 5, 2003, when the licensee identified that while draining one train of DOSTs, the other train of DOSTs overflowed due to leak-by of a DOST isolation valve.

The 1B DG fuel oil sub-system, or train, was included in the licensee's margin management database because the margin between the level in the DOST required to support operability and the level at which the DOST overflowed was low. Licensee procedure CC–AA–107, "Configuration Change Acceptance Testing Criteria," described the process the licensee used to develop testing requirements and acceptance criteria for configuration change packages. Step 4.1.4 of CC–AA–107 required that the licensee, "consider low margin conditions and high consequence failure modes, and identify test conditions that demonstrate appropriate margin and protection." Although the licensee's margin management database included the 1B DG fuel oil train, EC 398031 did not discuss the impact the modification had on the 1B DG fuel oil train, and did not identify any test conditions to demonstrate a margin was maintained.

On October 8, 2014, EC 398031 was implemented and DG fuel oil valves 1DO055B and 2DO055B were opened. On October 22, 2014, the licensee operated the 1B DG for routine surveillance testing, which also operated the 1B DG fuel oil transfer pumps. Following this surveillance, operators noted a slight increase in the level of the 1C DOST, which was associated with the 1A DG train. This unexpected increase in 1C DOST level was not entered into the licensee's CAP and the surveillance was considered to have been successfully completed. On November 20, 2014, the licensee again operated the 1B DG for routine surveillance testing. During this surveillance, control room operators received alarms that indicated low levels on the DOSTs associated with the 1B DG train and subsequently identified that the 1C DOST was overflowing. Operators subsequently determined that the overfill condition was due to leak-by of the closed 1C DOST inlet valve, 1DO001C. The licensee cycled the valve, which successfully addressed the leak-by condition. The licensee entered this issue into their CAP as IR 2415245.

On December 10, 2014, following 1A DG surveillance testing, the licensee cycled 1DO001C to fill the 1C DOST and the leak-by returned, but was not identified until

December 22, 2014, when the licensee operated the 1B DG for routine surveillance testing. The licensee also closed 1DO055B to isolate the leak-by pending repairs to 1DO001C.

On May 28, 2015, the licensee completed an evaluation and concluded that, absent operator action, the leak-by of valve 1DO001C that occurred on November 20, 2014, and, then again, on December 22, 2014, would have prevented the 1B DG from operating for its 7-day design mission time. Therefore, the licensee determined that the 1B DG was inoperable during the time the 1DO055B valve was open and this leak-by was present from October 8, 2014, through November 20, 2014, and from December 10, 2014, through December 22, 2014. Since the first period of inoperability exceeded the 1B DG Limiting Condition for Operation Allowed Outage Time of 14 days, the licensee determined that the event was reportable to the NRC in accordance with 10 CFR 50.73(a)(2)(i)(B) and submitted the associated LER on July 27, 2015.

Analysis: The inspectors determined that the licensee's failure to evaluate the impact of a design modification on a low margin 1B DG fuel oil system in accordance with licensee procedures was a performance deficiency.

Using IMC 0612, Appendix B, "Issue Screening," issued September 7, 2012, the inspectors determined that the performance deficiency was more than minor because it was associated with the Mitigating Systems cornerstone attribute of Design Control and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage).

The inspectors utilized Exhibit 2, "Mitigating Systems Screening Questions," of IMC 0609, Appendix A, "Significance Determination Process for Findings At-Power," dated June 19, 2012, to evaluate the significance. Because the finding represented an actual loss of function of one train of the Emergency AC [Alternating Current] Power System for greater than its TS allowed outage time, a detailed risk evaluation was required.

The detailed risk evaluation was performed by a Region III SRA. The failure probability of a component to operate is directly related to its mission time. By convention, in a Level 1 internal events probabilistic risk assessment, mission time is usually specified as 24 hours. After 24 hours, multiple options for responding to an event are assumed to be available so that the residual risk results, beyond the 24-hour timeframe, would be negligibly small. In addition, the supporting requirements in the probabilistic risk assessment standard suggests a mission time of 24 hours and all of the NRC's standard plant analysis risk models assume a 24-hour mission time.

For this issue, the licensee demonstrated that, although inoperable, the 1B DG would be available for 24 hours with this condition present. Therefore, based on the 1B DG being available for 24 hours, the SRAs determined that the increase in core damage frequency (ΔCDF) for this issue was negligible and therefore the issue was of very low safety significance (i.e., Green).

The finding had a cross-cutting aspect in the Avoid Complacency component of the Human Performance cross-cutting area because the licensee failed to recognize and plan for the possibility of latent issues while expecting successful outcomes.

Specifically, the licensee failed to recognize that the modification resulted in the licensee operating the DG fuel oil system in a configuration that it had not routinely operated in, exposing previously unidentified deficiencies (H.12).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented instructions, procedures, and drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings.

Exelon procedure NO–AA–10, "Quality Assurance Topical Report," Chapter 5, required, in part, that modifications to equipment be performed in accordance with written procedures.

Step 4.1.4 of licensee procedure CC–AA–107, "Configuration Change Acceptance Testing Criteria," which was a quality procedure subject to the requirement of NO–AA–10 and 10 CFR 50, Appendix B, Criterion V, required the licensee to "consider low margin conditions and high consequence failure modes, and identify test conditions that demonstrate appropriate margin and protection," when making modifications to equipment.

Byron TS 3.8.3, "Diesel Fuel Oil," required, in part, that the stored diesel fuel oil shall be within the limits for each required DG when the associated DG is required to be operable. Action D.1 of TS 3.8.3 required the licensee to immediately declare the associated DG inoperable for one or more DGs with diesel fuel oil not within limits for reasons other than those specified in Conditions A, B, and C.

Byron TS 3.8.1, "AC Sources—Operating," required, in part, that two DGs be capable of supplying the onsite Class 1E AC electrical power distribution system in Mode 1. Action B.5 of TS 3.8.1 required the licensee to restore the DG to an operable status within 14 days if one DG is inoperable, and Action G.2 of TS 3.8.1 required, in part, that the licensee be in Mode 5 within 36 hours if Action B.5 was not met within its associated completion time.

Contrary to the above, on October 4, 2014, the licensee approved and subsequently implemented EC 398031, "Change Normal Positions of 1DO057, 1DO055B, 2DO2055B, & 2DO2057," through which the licensee implemented a modification to safety-related portions of the DG fuel oil system which revised the normal positions of DG fuel oil transfer pump isolation valves from closed to open, but failed to consider the low margin of the 1B DG fuel oil train and demonstrate that an appropriate margin was maintained as required by Step 4.1.4 of CC–AA–107.

This resulted in leakage from the 1B DG fuel oil train rendering the 1B DG inoperable from October 8, 2014, through November 20, 2014, a total of 43 days, which was greater than the AOT specified in TS 3.8.3 and TS 3.8.1. Additionally, because the licensee was not aware of the DG inoperability during this timeframe, the required actions of TS 3.8.1.B.5 and 3.8.1.G.2 were not completed.

Because this violation was of very low safety significance and it was entered into the licensee's CAP as IRs 2415245, 2428856, and 2506852, it is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy
(NCV 05000454/2015007-01; 05000455/2015007-01, Failure to Evaluate the Impact of a FLEX-Related Configuration Change on Available DG Fuel Oil Margin.)

Failure to Evaluate Operability and Reportability in Accordance with the Issue Report Screening Procedure

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings", when the licensee failed to adequately evaluate an issue entered into the CAP for operability and reportability. Specifically, the licensee failed to evaluate operability and reportability after DG fuel oil was identified to be unexpectedly overflowing into an "A" train DOST when a "B" train DG fuel oil transfer pump was operating.

Description: On November 20, 2014, during a routine 1B DG surveillance test, control room operators received alarms indicating low DG fuel oil levels 1B DG DOSTs. The licensee dispatched operators to the DOSTs and identified that the 1C DOST for the 1A DG was overflowing. The licensee identified that the overflow was caused by leak-by on 1DO001C, the normally closed inlet valve to the 1C DOST. The licensee cycled the valve and successfully addressed the condition.

Following the event, the licensee entered this issue into their CAP as IR 2415245. In this IR, a concern that implementation of EC 398031 generated additional flow paths for the DG fuel oil transfer pumps and that, "leak-by is more plausible which could rob the required TS flow to the DG day tanks from the transfer pumps," was documented. The IR recommended that the licensee "verify that diesel oil transfer pumps are still supplying sufficient flow to diesel generators."

Licensee procedure PI–AA–120, "Issue Identification and Screening," directed Operations shift management to perform a review of the IR, including documenting whether the condition impacted a TS function, determining if the operability of any structure, system, or component (SSC) was affected by the condition described, and determining if the issue was reportable in accordance with the licensee's reportability manual. On November 21, 2014, Operations shift management documented that the IR did not involve equipment covered by TSs and that no reportability manual threshold was exceeded. This determination was reviewed by the SOC with no comments.

The inspectors questioned this operability determination because it failed to address the impact the leak-by had on the ability of the 1B DG to operate for its 7-day mission time. On December 1, 2014, the Shift Manager revised the operability determination to document that the DOST system was operable as the leak-by resulted in the 1C DOST filling to an overflow condition, which was greater than the level required by TSs. Although correct for the 1C DOST, this review did not address operability of the 1B DG and associated DOSTs.

On December 22, 2014, during the next routine 1B DG surveillance test, control room operators again received low level alarms from the DOSTs associated with the 1B EDG (i.e., the 1B and 1D DOSTs.) In response to these alarms, operators were dispatched to

close the 1B DG fuel oil transfer pump discharge valve, 1DO055B, which was opened through implementation of EC 398031. By closing this valve, the licensee isolated the leak-by. The licensee entered this issue into their CAP as IR 2428856 and in the IR included a recommendation to evaluate how long the 1B EDG could run at full load with fuel leaking past 1DO001.

Operations shift management reviewed this IR on December 23, 2014, and documented that the DG fuel oil system was operable as the leak-by resulted in the 1C DOST filling to an overflow condition, which was greater than the level required by TSs. Again, the inspectors questioned the licensee concerning the operability determination for IR 2428856 and IR 2415245, and, on December 23, 2014, the operability determination was revised to include a statement that the DG fuel oil system associated with the 1B EDG remained operable as DOST levels remained above the level required by TSs, but that the 1DO055B valve should not be reopened until either the 1DO001C valve was repaired or the licensee performed an evaluation regarding the impact the leakage had on the 1B DG mission time of 7 days.

The licensee chose not to repair 1DO001C, but instead requested that Engineering perform an evaluation on the impact of the leakage on the mission time of the 1B DG with a due date of April 30, 2015. The due date for this evaluation was extended six times due to higher priority assignments, and on May 28, 2015, the licensee completed the evaluation and documented in IR 2506852 that the rate of leakage from the 1B DG fuel oil train to the 1A DG fuel oil train was great enough such that the 1B DG would not be able to operate for its 7-day design mission time without operator intervention on both occasions of DG fuel oil leak-by.

On July 27, 2015, the licensee submitted LER 05000454/2015-003-00 for one train of the DG system being inoperable for greater than the AOT because the 1B DG would have been unable to meet its 7-day mission time for greater than the 14-day Limiting Condition for Operation in TS 3.8.1, Condition B.

Analysis: The inspectors determined that the failure to document whether the condition identified in IR 2415245 and IR 2428856 impacted a TS function and determine if the issue was reportable was a performance deficiency.

Using IMC 0612, Appendix B, "Issue Screening," issued September 7, 2012, the inspectors determined that the performance deficiency was more than minor, because it was associated with the Mitigating Systems cornerstone attribute of Design Control and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage).

The inspectors utilized Exhibit 2, "Mitigating Systems Screening Questions," of IMC 0609, Appendix A, "Significance Determination Process for Findings At-Power," dated June 19, 2012, to evaluate the significance. Because the finding was not a deficiency affecting the design or qualification of the SSC, did not represent a loss of system and/or function, did not represent an actual loss of function for greater than its TS AOT, and did not represent a loss of function of non-TS trains of equipment, the finding screened as having very low safety significance (i.e., Green).

The finding had a cross-cutting aspect in the Teamwork component of the Human Performance cross-cutting area, because licensee individuals and work groups failed to communicate and coordinate their activities within and across organizational boundaries to ensure nuclear safety was maintained. Specifically, nuclear safety and reactor operators failed to communicate within their organizations to ensure both groups understood the safety impact of the leaking valve. Additionally, other workgroups within the licensee's organization that reviewed the IRs, including the SOC, the MRC, and Engineering, had an opportunity to question or challenge the Operations shift management's inadequate operability basis (H.4).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality be prescribed by documented instructions, procedures, and drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, and drawings.

Exelon procedure NO–AA–10, "Quality Assurance Topical Report," Chapter 5, required, in part, that activities governed by Exelon's quality assurance program be performed as directed by documented procedures.

Step 4.4.6.2 and Step 4.4.6.5 of licensee procedure PI–AA–120, "Issue Identification and Screening;" a procedure governed by Exelon's quality assurance program, directed that Operations shift management "document whether the condition impacts a TS function," and, "determine if the issue is reportable…and document the basis of the determination and actions," respectively.

Contrary to the above, on November 21, 2015, and as documented in IR 2415245, when the 1B DG fuel oil transfer pump was running and DG fuel oil was identified to be unexpectedly overflowing the 1A DOST as a result of leak-by from the normally closed inlet valve to the 1C DOST, the licensee failed to document the TS function impacted and determine if the issue was reportable as required by Step 4.4.6.2 and Step 4.4.6.5 of licensee procedure PI–AA–120, "Issue Identification and Screening."

Because this violation was of very low safety significance and it was entered into the licensee's CAP as IR 2506852, it is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000454/2015007-02, Failure to Evaluate Operability and Reportability in Accordance with the Issue Report Screening Procedure)**.

(3) Effectiveness of Corrective Actions

The inspectors concluded that, overall, corrective actions reviewed were usually found to be appropriately focused to correct the identified problem and were implemented in a timely manner commensurate with the issue's safety significance. Issues identified through root or ACEs were resolved in accordance with the CAP procedure and NRC regulatory requirements. Corrective actions that were created to prevent the recurrence of significant issues were generally comprehensive, thorough, and timely.

The inspector's reviewed a sample of licensee's corrective actions to specifically address prior violations of NRC requirements. The inspectors determined that, generally, the licensee adequately corrected the violation in a timely manner. However,

the inspectors identified one finding in which the licensee failed to correct an issue in a timely manner.

Findings

Failure to Analyze Recycle Holdup Tank Inlet Piping Loads

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated VIO of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” when licensee personnel failed to evaluate the effect of dynamic loads on inlet piping from Unit 1 and Unit 2 RHR suction relief valves that discharge to the Recycle Holdup Tank (RHUT); and, as a result, failed to verify the adequacy of the RHUT design to withstand design loads that resulted from a discharge from RHR system suction relief valves into the RHUT.

Description: On June 20, 2007, the NRC identified a concern with the available quench volume in the RHUT, and the absence of an analysis for water hammer loads on RHUT inlet piping following an RHR suction relief valve actuation. The RHR suction and discharge relief valves were originally designed to discharge to the pressurizer relief tank to ensure adequate quenching of steam. During construction, the piping was re-routed so that the RHR system suction relief valves discharged into the RHUT, located outside of containment, instead of the pressurizer relief tank, which was located inside of containment. The licensee’s review of this issue identified that the RHUT inlet pipe supports were analyzed to include seismic loads, which provided margin to accommodate dynamic water hammer loads in the direction of the support restraint. However, the NRC identified that postulated dynamic water hammer loads could create piping forces in directions that were not restrained by the existing pipe supports. The licensee entered this issue into their CAP as IR 680626 and IR 622574.

On November 12, 2008, NRC inspectors completed a review of the previously identified issue and documented a finding of 10 CFR Part 50, Appendix B, Criterion III, “Design Control” with an associated NCV, based, in part, on the licensee’s failure to analyze the water hammer transient loads on RHUT inlet piping induced by postulated discharges from the RHR pump suction valves, (Reference: NCV 05000454/455/2008009-02, Failure to Analyze Inlet Piping Loads and Establish an Adequate HUT [Holdup Tank] Quench Volume). Specifically:

- *Contrary to the above (Ref: 10 CFR Part 50, Appendix B, Criterion III, “Design Control), from plant construction to September 28, 2008, the licensee failed to verify the adequacy of the HUT design. Specifically, the licensee failed: (1) to evaluate and maintain the required water volume necessary to quench the RHR system relief valve discharges into the HUT and incorporate appropriate minimum HUT level requirements into the HUT level control procedures; and (2) to evaluate the effect of dynamic "water hammer" loads on inlet from relief valve discharges to the HUT*

On September 11, 2011, the inspectors completed a review of the corrective actions associated with NCV 05000545/545 2008009-02, Failure to Analyze Inlet Piping Loads and Establish an Adequate HUT Quench Volume. The inspectors determined that the licensee had failed to evaluate the effect of dynamic water hammer loads on the inlet from relief valve discharges to the HUT. The inspectors identified and documented a second Green finding; an associated NCV based upon the licensee’s failure to promptly

identify and correct a condition adverse to quality as required by 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action”, (Reference: NCV 05000/454/4552011008-01; Untimely Corrective Actions for Previous Identified Non-Cited Violations). Specifically:

- *Contrary to the above, as of September 2, 2011, the licensee failed to promptly correct two conditions adverse to quality as previously described in NCV 05000454/455/2008009-02 and (NCV 05000454/455/2009004-02, unrelated to this VIO). Specifically, the design control deficiencies related to these issue had not been corrected since the NCVs were initially issued in November 2008. . .*

This finding was issued as a NCV because it was determined to be of very low safety significance (i.e. Green) and was entered into the licensee’s CAP for resolution.

During this PI&R inspection, the inspectors reviewed the corrective actions associated with the two prior NCVs discussed above and concluded that the licensee failed to adequately address the issue. Although this non-conformance had existed since original plant licensing, the condition had not been corrected after the first NCV was issued in 2008.

At the end of the inspection, the licensee was waiting for a vendor to complete several transient hydraulic loading calculations. Additionally, the licensee anticipated that approximately 20 piping supports will be added to the system. These actions were planned for completion by the end of 2015.

<u>Analysis</u>: The inspectors determined that the licensee’s failure to correct two prior NCVs associated with this finding was a performance deficiency.

The inspectors determined that the performance deficiency was more than minor in accordance with IMC 0612, “Power Reactor Inspection Reports,” Appendix B, “Issue Screening,” because the finding was associated with the Design Control attribute of the Barrier Integrity Cornerstone and adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the licensee’s existing RHR piping configuration had not adequately addressed the postulated dynamic water hammer loads that could occur following the actuation of the RHR suction relief valves. This performance deficiency had the potential to increase both on-site and off-site dose consequences based upon the failure to complete a design modification that met design requirements.

The SRAs performed a detailed risk evaluation and considered two specific cases.

Case 1: Unit Shutdown with the RHR System In-Service in the Shutdown Cooling Mode

- The RHR suction relief valves are designed to be isolated from the RCS by a motor-operated valve when the RHR system is not in-service (and interlocked to prevent opening if RCS pressure is greater than 360 pounds per square inch gauge (psig)). The finding would not affect the likelihood of core damage, but had potential implications for the integrity of the containment (i.e., Large Early Release Frequency (LERF)). The finding was determined to be a Type B finding as defined in IMC 0609, Appendix H, “Containment Integrity Significance Determination

Process.” Westinghouse previously completed an evaluation and determined that the RHUT would not exceed its design pressure or temperature under the condition of an RHR relief valve lifting. Also, the discharge from the RHR suction relief valve would only potentially adversely affect the downstream relief valve piping if the Reactor Coolant System (RCS) temperature was above 212°F. The SRAs reviewed IMC 0609, Appendix H, and IMC 0308, Attachment 3, Appendix H, “Technical Basis - Containment Integrity Significance Determination Process (IMC 0609, Appendix H) For Type A and Type B Findings—Full Power and Shutdown Operations,” to determine the impact of the finding on LERF. According to Table B.3 of IMC 0308, Attachment 3, Appendix H, the annualized CDF with the reactor head bolted on the reactor vessel flange (as is the case with the plant in Mode 4) for an in-depth shutdown mitigation capability that would exist for the plant in Mode 4 (an in-depth shutdown mitigation capability is defined in Table 6.8 of IMC 0609, Appendix H) was 1.0E-7/year. To provide an upper bound on the change in LERF, it was conservatively assumed that one-tenth of the core damage events were associated with an RHR suction relief valve failing to open. In addition, Braidwood Inspection Report 05000456/2008005; 05000457/2008005 documented that Braidwood Unit 1 had an RHR suction relief valve actuation that had not resulted in damage to downstream piping and pipe supports. This event was used to calculate a mean failure probability for the piping with a lift of an RHR suction relief valve (using a Bayesian update with a Jeffrey’s non-informative prior). The result was a mean failure probability of the downstream relief valve piping of 0.25. Using a LERF factor of 1.0 (i.e., all core damage events result in a large early release), an upper bound estimate for the ΔLERF associated with the performance deficiency for Case 1 was therefore calculated to be about 2.5E-9/year.

Case 2: Unit in Recirculation Mode or on Shutdown Cooling Following Loss of Coolant

- For Loss-of-Coolant-Accident (LOCA) or Steam Generator Tube Rupture (SGTR) events, the performance deficiency would not affect the likelihood of core damage, but had potential containment integrity implications (i.e., LERF). To provide an upper bound on LERF associated with a LOCA or SGTR, it was conservatively assumed that during each core damage event associated with a LOCA or SGTR the RHR suction relief valves in both RHR trains would lift once while the plant was either in the emergency core cooling system recirculation mode or while aligned for shutdown cooling. Using the Byron standard plant analysis risk model, version 8.21, and the associated risk analysis software (SAPHIRE version 8.0.8.0), the total CDF associated with a LOCA (large-, medium-, and small-break LOCAs) and SGTR events was determined to be 3.24E-6/year. Using Table 24 from NUREG/CR-7037, “Industry Performance of Relief Valves at U.S. Commercial Power Plants through 2007,” the probability of an RHR relief valve to fail to close once it is actuated is 1.05E-3. Per the discussion above, the mean probability failure for the failure of relief valve discharge piping with a lift of an RHR suction relief valve was 0.25. Using a LERF factor of 1.0 (i.e., all core damage events result in a large early release), an upper bound estimate for the ΔLERF associated with the performance deficiency for Case 2 was therefore calculated to be about 1.7E-9/year. An upper bound estimate for the LERF associated with the performance deficiency is estimated by adding the results from Case 1 and Case 2 above, which results in 4.2E-9/year.

As a result, the finding was determined to be of very low safety significance (i.e, Green).

This finding had a cross-cutting aspect in the Resources component of the Human Performance cross-cutting area because leaders at the station did not ensure that personnel, equipment, procedures, and other necessary resources were available and adequate to correct the condition adverse to quality over the past three years. Specifically, leaders did not ensure that personnel, equipment, procedures, and other necessary resources were available and adequate to correct the condition adverse to quality over the past three years (H.1).

Enforcement: Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” requires, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis for SSCs, are correctly translated into specifications, drawings, procedures, and instructions, and that design control measures shall provide for verifying or checking the adequacy of the design.

Contrary to the above, from initial plant construction until August 11, 2015, the licensee failed to verify the adequacy of the design of the Byron Unit 1 and Unit 2 RHUTs, which were safety-related components subject to the requirements of Title 10 CFR Part 50, Appendix B, Criterion III, “Design Control.”

Specifically, the licensee failed to evaluate the effect of dynamic loads on inlet piping from Unit 1 and Unit 2 RHR system suction relief valves that discharge to the RHUTs; and, as a result, failed to verify the adequacy of the RHUT design to withstand design loads that would result from the actuation of RHR system suction relief valves. In this case, the licensee had not restored compliance within a reasonable period of time (i.e. in a time frame commensurate with the significance of the violation) after the violation was identified (i.e., a NCV of Title 10 CFR 50, Appendix B, Criterion III, “Design Control,” previously issued in February 2009 and an additional NCV of Title 10 CFR, Appendix B, Criterion XVI, “Corrective Action,” previously issued in October 2010). As a result, the conditions for considering the violation as non-cited, as identified in Section 2.3.2(a)(2) of the Enforcement Policy, were not met. Therefore, the violation is being cited in the attached Notice of Violation. **(VIO 05000454/2015007-03; 05000455/2015007-03, Failure to Analyze RHUT Inlet Piping Loads)**

.2 Use of Operating Experience

a. Inspection Scope

The inspectors reviewed the licensee’s implementation of the facility’s OE program. Specifically, the inspectors reviewed OE program implementing procedures, attended routine CAP meetings to observe the screening of OE information, reviewed completed evaluations of OE issues and events at other facilities, and reviewed selected periodic assessments of the OE composite performance indicators. The inspectors performed this review to determine whether the licensee’s OE program was effectively integrating OE into the performance of daily activities, whether the evaluation of issues were proper and conducted by qualified personnel, whether the OE program was sufficient to prevent the future occurrence of previous industry events, and to determine whether issues identified by NRC or the industry were entered into the licensee’s OE database as prescribed by procedure and were properly evaluated for applicability and significance. Additionally, the inspectors assessed if corrective actions resulting from OE reviews were identified and implemented in an effective and timely manner.

b. Assessment

In general, OE was effectively utilized at the station. The inspectors observed that OE was discussed as part of the daily station and pre-job briefings. Industry OE was effectively disseminated across the various plant departments and no issues were identified during the inspectors' review of licensee OE evaluations. During interviews, several licensee personnel commented favorably on the use of OE in their daily activities.

The inspectors did not identify any instances where procedural OE review requirements were not met. Generally, OE that was applicable to the station was thoroughly evaluated and actions were taken to address any issues that resulted from the evaluations in a timely manner.

Findings and Observation

No findings were identified.

.3 Assessment of Self-Assessments and Audits

a. Inspection Scope

The inspectors reviewed selected self-assessments, including adverse trend assessments and quality assurance audits, to assess the licensee's ability to identify and enter issues into the CAP with the appropriate characterization, to prioritize and evaluate issues commensurate with their safety significance, and to implement effective corrective actions in a timely manner. The inspectors also evaluated whether self-assessments and audits were effectively managed and adequately encompassed the subject areas and verified that assessments were conducted in accordance with plant procedures.

b. Assessment

The inspectors concluded that self-assessments and audits were typically accurate, thorough, and effective at identifying issues and enhancement opportunities at an appropriate threshold. Nuclear Oversight (NOS) and department audits and self-assessments were completed by personnel knowledgeable in the subject area and were generally thorough and critical. The inspectors observed that CAP items had been initiated for issues identified through the NOS audits and self-assessments. The inspectors reviewed the self-assessment performed on the CAP and found no issues and generally agreed with the overall self-assessment results and conclusions.

Findings

No findings were identified.

.4 Assessment of Safety-Conscious Work Environment

a. Inspection Scope

The inspectors assessed the Safety-Conscious Work Environment aspect of the station's safety culture. This assessment was performed primarily by reviewing IRs, by talking with Byron station workers from various departments, and by reviewing open and closed issues documented in the ECP. This inspection effort was performed to determine if plant employees were willing to raise issues related to nuclear safety without a fear of retaliation.

b. Assessment

Based on the results of the inspection, the inspectors concluded that, in general, station employees across all departments felt free to raise safety concerns without a fear of retaliation, were capable in utilizing the CAP computer program to document issues, were aware of other methods such as the ECP through which concerns could be raised; and generally felt that issues could be discussed openly with their supervision and management.

Findings

No findings were identified.

4OA5 Other Activities

(Open) Unresolved Item (URI): Potentially Inadequate Evaluation/Corrective Actions: Diesel Oil Storage Tanks (DOST) Vent Line Seismic Supports and Tornado Missile Protection

The inspectors identified a concern that the licensee's evaluation and corrective actions may have been inadequate following identification that DOST vent lines may not be seismically supported and adequately protected against tornado missiles as described in the Updated Final Safety Analysis Report (UFSAR) and in an NRC Safety Evaluation Report (SER). The deficient condition was NRC-identified and documented as an NCV in NRC Inspection Report 05000454/2009004-02; 05000455/2009004-02, which was issued in 2009; and was entered into the licensee CAP as AR 877430 and AR 933712.

According to the description in UFSAR Section 9.5.4.2, although the DOSTs are safety-related tanks required to remain operable during a tornado event, the tank fill and vent lines are classified as nonsafety-related. In response to an NRC reviewer comment during the license application process that these lines should be designed safety-related and tornado missile protected, the licensee provided a formal response which included, in part, the following (Question 040.99, Commonwealth Edison letter from T. R. Tramm to Harold R. Denton, dated December 28, 1981):

- Additional supports will be added to maintain integrity of the lines during design basis seismic events;
- Fill and vent lines are not safety-related while the tanks are;
- Impact from a tornado missile will not result in loss of function as breakage will occur before crimping;
- In the event of damage, a capped off 4" Category I line could be opened for use as an emergency vent or fill line; and
- A 4" Category I tank overflow line could be used as a vent.

This position was accepted by the NRC based on the following as documented in the SER (NUREG 0876, February 1982, Section 9.5.4.2):

- Commitment to seismically support the fill and vent lines;
- In case of damage due to tornado missiles, availability of unused flanged connections that can be used as fill and vent openings; and the
- Lines are designed to American National Standards Institute (ANSI) B31.1

Following a review of available licensee documentation, the inspectors identified that the commitment for seismically supporting the vent lines may not have been met. The availability of the unused flanged connections was also uncertain as there were no administrative procedures in place for such actions. The licensee was also unable to justify the "break prior to leak" statement. Instead, the licensee was relying on the vent path through the overflow line as was discussed in the response to Question 040.99 above. Because of the loop seals in the overflow piping, additional evaluations and loop seal modifications were performed to demonstrate that the tanks were structurally adequate for the maximum vacuum associated with the loop seal configurations. The code of construction for the tanks was the American Society of Mechanical Engineers (ASME) Section III, Division 1, sub-section ND, 1974 edition. However, due to a partial vacuum resulting from the use of overflow piping as a vent path, the use of a

methodology that was different than that described in licensee calculation BYR13–096 was required.

Based on discussions with the licensee, the licensee's view is that since the alternate vent path is provided, the vent lines no longer require seismic supports. The inspectors' interpretation based on the SER, UFSAR, and the licensee response to the NRC question as described above is that the acceptance of the alternate vent path scenario was applicable to the tornado missile event only, and that the licensee was still required to seismically support the vent lines. Additionally, while the licensee response to Question 040.99 included a discussion of using overflow lines as alternate vent paths, the NRC acceptance was based on the use of unused flanged lines. Further review is needed to determine the correct interpretation of the SER description and the design basis for seismic support and tornado missile protection requirements for the DOST vent lines.
This issue will remain open pending further NRC review to ensure that the licensee is in compliance with their current licensing basis. **(URI 05000454/2015007-04; 05000455/2015007-04, Potentially Inadequate Evaluation/Corrective Actions: Diesel Oil Storage Tank (DOST) Vent Line Seismic Supports and Tornado Missile Protection)**

4OA6 Management Meetings

.1 Exit Meeting Summary

On August 11, 2015, the inspectors presented the inspection results to Mr. T. Chalmers, 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.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee

R. Kearney, Site Vice President
T. Chalmers, Plant Manager,
A. Corrigan, Regulatory Assurance
L. Zurawski, Regulatory Assurance
D. Johnson, Reactor Services Manager
B. Barton, Radiation Protection Manager
R. Gaston, Corporate Licensing Manager
C. Keller, Engineering Director
J. Reed, Radiation Protection
B. Currier, Engineering
B. Quigley, Engineering
K. Passmore, Engineering
D. Sargent, Engineering
M. Ryterski, Engineering
R. Lawlor, Operations
P. Woessner, Maintenance
P. Escatel, Maintenance
M. Page, Engineering
K. McGuire, Chemistry
G. Contrady, Reg Assurance

Nuclear Regulatory Commission

E. Duncan, Chief, Branch 3, Division of Reactor Projects

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

05000454/2015007-01; 05000455/2015007-01	NCV	Failure to Evaluate the Impact of a FLEX-Related Configuration Change on Available DG Fuel Oil Margin
05000454/2015007-02;	NCV	Failure to Evaluate Operability and Reportability in Accordance with the Issue Report Screening Procedure
05000454/2015007-03; 05000455/2015007-03	VIO	Failure to Analyze RHUT Inlet Piping Loads
05000454/2015007-04; 05000455/2015007-04	URI	Potentially Inadequate Evaluation/Corrective Actions: Diesel Oil Storage Tank (DOST) Vent Line Seismic Supports and Tornado Missile Protection

Closed

05000454/2015007-01; 05000455/2015007-01	NCV	Failure to Evaluate the Impact of a FLEX-Related Configuration Change on Available DG Fuel Oil Margin
05000454/2015007-02; 05000455/2015007-02	NCV	Failure to Evaluate Operability and Reportability in Accordance with Issue Report Screening Procedure

LIST OF DOCUMENTS REVIEWED

The following is a list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety, but rather, that selected sections of 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.

Procedures

0BDCSR 3.3.1.1; Wet Cask Pit/MPC Boron Concentration Verification; Revision 2
0BMSR SX-5; Inspection of River Screen House and Essential Service Water Cooling Tower Basins (CM–4); Revision 10
1BOA ENV–1; Adverse Weather Conditions; Revision 101
1BOSR 8.1.11–2; 1B Diesel Generator Sequencer Text 18 Month; Revision 25
BOP DO–7; Filling Unit 1 Diesel Generator Storage Tanks; Revision 19
CC–AA–107; Configuration Change Acceptance Testing Criteria; Revision 9
CC–AA–309–1001; Guidelines for Preparing and Processing of Design Analyses; Revision 7
EI–AA–101; Employee Concerns Program; Revision 10
ER–AA–200–1001; Equipment Classification; Revision 0
ER–AA–1200; Critical Component Failure Clock; Revision 12
LS–AA–104–1001; 1/2BOA ENV–1, Adverse Weather Conditions; Revision 100/101
LS–AA–115–1003; Processing of OPEX 3 Evaluations; Revision 3
MA–AA–716–230–1001; Oil Analysis Interpretation Guideline; Revision 13
MA–AA–716–230–1002; Vibration Analysis/Acceptance Guideline; Revision 3
MA–AA–716–230–1001; Oil Analysis Interpretation Guideline; Revision 17
MA–AA–716–230–1001; Oil Analysis Interpretation Guideline; Revision 16
MA–AA–716–230–1002; Vibration Analysis/Acceptance Guideline; Revision 4
MA–AA–716–230–1001; Oil Analysis Interpretation Guideline; Revision 15
MA–AA–716–230–1001; Oil Analysis Interpretation Guideline; Revision 14
PI–AA–120; Issue Identification and Screening Process; Revision 1
PI–AA–125; Corrective Action Program; Revision 2
PI–AA–125–1001; Root Cause Analysis Manual; Revision 1
PI–AA–125–1003; Apparent Cause Evaluation Manual; Revision 1
PI–AA–125–1003; Apparent Cause Evaluation Manual; Revision 2
PI–AA–125–1005; Coding and Analysis Manual; Revision 0
PI–AA–126; Self–Assessment and Benchmark Program, Revision 0
PI–AA–126–1001–F–01; Focused Area Self-Assessment; Revision 0
PI–AA–126–1005; Check-in Self Assessments; Revision 0
SA–AA–123; Injury & Illness Reporting & Recordkeeping; Revision 13
SM–AC–4005; Supplier Performance Measurement and Management; Revision 12
WC–AA–101; On-Line Work Control Process; Revision 25
WC–AA–106; Work Screening and Processing; Revision 15
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IR 649581; Potential Vulnerability with RH Suction Relief Disch to HUT; July 12, 2007
IR 649710; Potential Vulnerability with RH suction Relief Disch to HUT; July 13, 2007

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IR 679954; Recycle Hold Up Tank Level Administrative Controls; October 4, 2007
IR 680626; NRC Potential Green Finding and Associated NCV—HUT Level; October 5, 2007
IR 966696; High Rad Turnstile Left Unlocked; September 18, 2009
IR 1130683; Severe Thunderstorm Warning Elevated OLR to Orange on Unit 1; October 26, 2010
IR 1234842; Replacement of Obsolete Parts on Process Radiation Monitors; June 30, 2011
IR 1267355; Oil Analysis of Motor Driven Fire Pump Shows Elevated Iron; September 23, 2011
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IR 1296141; NER NC–11–045–Y Fleet Wide Actions; November, 30 2011
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IR 1399508; Actions for HUT Issues (Corrective Action No. 680626–01); July 13, 2012
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IR 153283; 1Q2013 NRC Green NCV Embedment Plate Design Deficiencies; May, 13 2013
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IR 1573471; Security Equipment—BRE 9 Door Difficult to Open and Close; October 17, 2013
IR 1573810; 1A Diesel Oil Storage Tank Overflow; May 6, 2003
IR 1575097; Malware Detected on End User Computer; October 14, 2013
IR 1576654; Security VVRO Suggested Enhancement; October 25, 2013
IR 1578289; EC 379850 Failed to Adequately Evaluate Boron Corrosion; 10/29/13
IR 1578544; Failed PTM WO 1025291–10 and 11; October 30, 2013
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IR 1584371; Antifreeze Leak on Security Diesel; November 12, 2013
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IR 1595834; Byron Station Duty Chemist Meeting Outcomes & Actions; December 11, 2013
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IR 15999671; Inservice Inspection, Inservice Testing, and Appendix J Audit Report NOSA–BYR–14–08; August, 27 2014
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IR 2525134; Reactivity Management Performance Indicator below Goal; July 8, 2015
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IR 2533143; NRC PI&R Identified Issue Report Was Not Properly Screened; July 27, 2015
IR 2533282; NRC PI&R—EACE Action Not Generated to Revise PCM Template; July 27, 2015
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IR 2535701; IR Not Routed for WGE as Intended by SOC; July 31, 2015
IR 2536009; CA Extension Not Approved By MRC; July 31, 2015
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IR 2539025; P&IR Identified—UFSAR Update Needed; August, 7 2015
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Drawings

M–50, Sheet 1A; Diagram of Diesel Fuel Oil; Revision AS
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DC–ST–03–BY/BR; Structural Project Design Criteria; Revision 24
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EC 3950102 000; OP Eval 13–008—Hydrodynamic Analysis of RH Suction Relief to the Boric Acid Relief Header; November 5, 2013, July 18, 2014
EC 3950102 001; OP Eval 13–008—Hydrodynamic Analysis of RH Suction Relief to the Boric Acid Relief Header; July 18, 2014
EC 398031; Change Normal Positions of 1DO057, 1DO055B, 2DO2055B, & 2DO2057; Revision 000
FASA 2436501; Pre-NRC Problem Identification and Resolution (PI&R) 71152 Inspection; June 1, 2015
Service Request 9768; 1B EDG DOST TS Minimum Fuel Storage Criteria Increased to >96% Level; October 30, 2007
WR 97299; Valve Leaks By and Over Flowed the Tank; May 6, 2003
WO 573989; Valve Leaks By and Over Flowed the Tank; January 22, 2005
WR 483631; Inadvertent Drain of 1D/1B DO Storage Tanks; December 24, 2014
WO 1796243; Valve Leaks By and Over Flowed the Tank; January 2, 2015

LIST OF ACRONYMS USED

AC	Alternating Current
ACE	Apparent Cause Evaluation
ADAMS	Agency-wide Documents Access Management System
ANSI	American National Standards Institute
AOT	Allowed Outage Time
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
DG	Emergency Diesel Generator
DOST	Diesel Oil Storage Tank
DRP	Division of Reactor Projects
EC	Engineering Change
ECP	Employee Concerns Program
FLEX	Diverse and Flexible Coping Capability
HUT	Holdup Tank
IMC	Inspection Manual Chapter
IR	Issue Report
LOCA	Loss-of-Coolant-Accident
LER	Licensee Event Report
LERF	Large Early Release Frequency
MRC	Management Review Committee
NCV	Non–Cited Violation
NOS	Nuclear Oversight
NRC	U.S. Nuclear Regulatory Commission
OE	Operating Experience
PARS	Publicly Available Records System
PI&R	Problem Identification and Resolution
RHUT	Recycle Holdup Tank
RHR	Residual Heat Removal
SDP	Significance Determination Process
SER	Safety Evaluation Report
SGTR	Steam Generator Tube Rupture
SOC	Station Oversight Committee
SRA	Senior Reactor Analyst
SSC	Structure, System, or Component
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VIO	Cited Violation

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 enclosures, 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 (PARS) 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 Duncan, Chief
Branch 3
Division of Reactor Projects

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

Enclosure:
1. Notice of Violation
2. Inspection Report 05000454/2015007;
   05000455/2015007
   w/Attachment:
   Supplemental Information

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