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

February 3, 2014

EA-11-051

Mr. Michael J. Pacilio
Senior Vice President, Exelon Generation Co., LLC
President and Chief Nuclear Officer, Exelon Nuclear
4300 Winfield Road
Warrenville, IL 60555

SUBJECT: BYRON STATION, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000454/2013005; 05000455/2013005

Dear Mr. Pacilio:

On December 31, 2013, 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 January 7, 2014, with Mr. B. Youman, and other members of your staff.

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

Based on the results of this inspection, seven findings of very low safety significance (Green) were identified. The findings were determined to involve violations of NRC requirements. However, because the findings were of very low safety significance and because the issues were entered into your Corrective Action Program (CAP), the NRC is treating these violations as Non-Cited Violations (NCVs) in accordance with Section 2.3.2 of the NRC's Enforcement Policy.

If you contest these violations or the 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 Byron Station.

If you disagree with the cross-cutting aspect assignment 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 Byron Station.

As a result of the Safety Culture Common Language Initiative, the terminology and coding of cross-cutting aspects were revised beginning in calendar year (CY) 2014. New cross-cutting aspects identified in CY 2014 will be coded under the latest revision to Inspection Manual Chapter (IMC) 0310. Cross-cutting aspects identified in the last six months of 2013 using the previous terminology will be converted to the latest revision in accordance with the cross-reference in IMC 0310. The revised cross-cutting aspects will be evaluated for cross-cutting themes and potential substantive cross-cutting issues in accordance with IMC 0305 starting with the CY 2014 mid-cycle assessment review.

In accordance with Title 10 of the Code of Federal Regulations 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 Public Document Room or from the Publicly Available Records System (PARS) component of 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:
Inspection Report 05000454/2013005; 05000455/2013005
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION III

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| Docket Nos: | 50-454; 50-455 |
| License Nos: | NPF-37; NPF-66 |
| Report No: | 05000454/2013005; 05000455/2013005 |
| Licensee: | Exelon Generation Company, LLC |
| Facility: | Byron Station, Units 1 and 2 |
| Location: | Byron, IL |
| Dates: | October 1 through December 31, 2013 |
| Inspectors: | J. McGhee, Senior Resident Inspector<br>B. Bartlett, Senior Resident Inspector<br>J. Robbins, Resident Inspector<br>R. Ng, Project Engineer<br>N. Féliz-Adorno, Reactor Engineer<br>M. Jones Jr., Reactor Inspector<br>S. Sheldon, Senior Reactor Engineer<br>J. Cassidy, Senior Health Physicist<br>M. Holmberg, Reactor Inspector<br>J. Laughlin, Emergency Preparedness Inspector<br>D. Jones, Reactor Inspector<br>B. Palagi, Senior Inspector<br>C. Thompson, Resident Inspector, Illinois Emergency Management Agency |
| Approved by: | E. Duncan, Chief<br>Branch 3<br>Division of Reactor Projects |

Enclosure

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## SUMMARY OF FINDINGS

Inspection Report (IR) 05000454/2013005 and 05000455/2013005; 10/01/13 - 12/31/13; Byron Station, Units 1 & 2; Heat Sink; Plant Modifications.

This report covers a 3-month period of inspection by resident inspectors and announced baseline inspections by regional inspectors. Seven Green findings were identified by the inspectors. The findings involved Non-Cited Violations (NCVs) of NRC requirements. 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 June 2, 2011. Cross-cutting aspects were determined using IMC 0310, "Components Within the Cross-Cutting Areas," dated October 28, 2011. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy dated January 28, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4.

### A. NRC-Identified and Self-Revealed Findings

**Cornerstone: Initiating Events**

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to maintain reactor vessel design specifications and analyses up-to-date for the 53 stud vessel head configuration applicable to Unit 2. Specifically, the reactor vessel Design Specification and Design Analysis did not reflect a modified and stuck stud number 11. The licensee entered this issue into their (CAP) as Issue Report (IR) 01578285, "Design Documentation is Not in Compliance with ASME [American Society of Mechanical Engineers].

  The inspectors determined that the performance deficiency was more than minor because it was associated with the Design Control attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions. The inspectors also answered 'Yes' to the more-than-minor screening question, "If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, the inspectors determined that this issue was more than minor because, if left uncorrected, the failure to maintain the Unit 2 reactor vessel design specification and analysis caused them to be inaccurate and if these documents were subsequently relied on for future design changes, the vessel design may not be adequate to maintain structural integrity during design basis events resulting in a loss-of-coolant-accident (LOCA). The inspectors performed a Phase 1 Significance Determination Process (SDP) screening and evaluated this issue by application of Questions 1 and 2. Questions 1 and 2 asked: "If after a reasonable assessment of degradation, could the finding result in exceeding the reactor coolant system leak rate for a small LOCA or could the finding have likely affected other systems used to mitigate a LOCA resulting in a total loss of their function (e.g., Interfacing System LOCA)?" In this case, the degradation prompting the reduction in the number of head studs and the licensee's failure to maintain the design analysis had not yet affected the ability of the reactor vessel to perform its design functions, so the inspectors answered these questions 'No' and this issue screened as having very low safety significance. The inspectors determined that this finding was not indicative of current performance, and therefore no cross-cutting aspect was assigned. (Section 1R18.1.b (2))

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XI, "Test Control," when licensee personnel failed to establish a program to monitor the corrosion effects on the reactor vessel flange integrity caused by the ingress of borated water below abandoned head stud number 11. The licensee entered this issue into their CAP as IR 01578289, "EC [Engineering Change] 379850 Failed to Adequately Evaluate Boron Corrosion."

  The inspectors determined that the performance deficiency was more than minor because it was associated with the Design Control attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions. The inspectors also answered 'Yes' to the more-than-minor screening question, "If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, the inspectors determined that this issue was more than minor because, if left uncorrected, the failure to adequately evaluate the long-term corrosion effects on reactor vessel flange integrity could result in a LOCA. The inspectors performed a Phase 1 SDP Screening and evaluated this issue by application of Questions 1 and 2. Questions 1 and 2 asked: "If after a reasonable assessment of degradation, could the finding result in exceeding the reactor coolant leak rate for a small LOCA or could the finding have likely affected other systems used to mitigate a LOCA resulting in a total loss of their function (e.g., Interfacing System LOCA)?" In this case, the degradation had not yet progressed to the point that would impact reactor vessel flange integrity, so the inspectors answered these questions 'No' and this issue screened as having very low safety significance. This finding had a cross-cutting aspect in the CAP component of the Problem Identification and Resolution cross-cutting area because the licensee did not take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity. Specifically, the licensee failed to develop a procedure for monitoring the boric acid corrosion induced wastage of the reactor vessel head flange as a corrective action resulting from a review of EC 379850 (P.1(d)). (Section 1R18.1.b (3))

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to perform an adequate thermal-mechanical analysis to support operation with a missing Unit 2 head stud. Specifically, the licensee did not perform a complete set of analyses under operating, faulted, and design conditions to confirm the associated stud and flange stresses would remain within the Code allowable limits. Consequently, the licensee did not recognize that the bearing stress under the head stud nuts at the vessel flange face exceeded the Code allowable stress. The licensee entered this issue into their CAP as IR 01578717, "Unit 2 RV [Reactor Vessel] Closure Stud Bearing Stress is Above ASME Allowed."

  The inspectors determined that the performance deficiency was more than minor because it was associated with the Design Control attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions. The inspectors also answered 'Yes' to the more-than-minor screening question, "If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, the inspectors determined that this issue was more than minor because, if left uncorrected, the failure to perform an adequate thermal-mechanical analysis could result in the inability of the reactor vessel to meet the design basis operating transient without a LOCA. The inspectors performed a Phase 1 SDP Screening and evaluated this issue by application of Questions 1 and 2. Questions 1 and 2 asked: "If after a reasonable assessment of degradation, could the finding result in exceeding the reactor coolant leak rate for a small LOCA or could the finding have likely affected other systems used to mitigate a LOCA resulting in a total loss of their function (e.g., Interfacing System LOCA)?" In this case, because of the available margins in the flange material strength, the inspectors answered these questions 'No' and this issue screened as having very low safety significance. This finding had a cross-cutting aspect in the Resources component of the Human Performance cross-cutting area because the licensee did not have complete, accurate, and up-to-date design documentation, procedures, and work packages. Specifically, the licensee failed to ensure the applicable ASME Code Section III design limit for bearing stress (design basis) was correctly translated into design document EC 379850 (H.2(c)). (Section 1R18.1.b (4))

**Cornerstone: Mitigating Systems**

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion XI, "Test Control," when licensee personnel failed to demonstrate the ability to isolate essential service water (SX) blowdown as credited in analyses described in the Updated Final Safety Analysis Report (UFSAR). Specifically, the licensee failed to periodically test the active function of the blowdown isolation valves. The licensee entered this issue into their CAP as IR 1579361, "Valves 0SX161A/B Closure Not Functionally Tested."

  The performance deficiency was determined to be more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone 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 screened as having very low safety significance because it did not result in the loss of operability or functionality. Specifically, the licensee reviewed recent history of the affected piping system and determined the subject blowdown isolation valves were opportunistically cycled without incident. The inspectors did not identify a cross-cutting aspect associated with this finding because it was confirmed not to reflect current performance due to the age of the performance deficiency. (Section 1R07.1.b (1))

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to develop appropriate intake structure silt level acceptance criteria. Specifically, the licensee used a non-conservative river water low level value as an input when developing silt level acceptance criteria. The licensee entered this issue into their CAP as IR 1582385, "Input Used in BYR 96-277 is Not Conservative," and planned to correct the acceptance criteria and revise the affected surveillance procedures.

  The performance deficiency was determined to be more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems to respond to initiating events to prevent undesirable consequences (i.e. core damage). The finding screened as having very low safety significance because it did not result in a loss of operability or functionality. Specifically, a historical review did not find an example where the as-found silt level resulted in an inoperable condition. The inspectors did not identify a cross-cutting aspect associated with this finding because it was confirmed not to reflect current performance due to the age of the performance deficiency. (Section 1R07.1.b (2))

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of Technical Specification (TS) 5.4.1, "Procedures," when licensee personnel failed to establish and implement a preventive maintenance schedule to replace hoses on the SX Makeup (MU) pump diesel engine. Specifically, the licensee failed to implement preventive maintenance procedures that required periodic replacement of hoses on pre-established schedules in accordance with vendor recommendations and the corporate Performance Centered Maintenance (PCM) template. The licensee entered this issue into their CAP as IR 01582656, "NRC ID [Identified] Vendor Manual Recommendation Not Being Implemented," and 01590368, "NRC ID – PCM Template/Vendor Manual Recommendation," and planned to evaluate the current maintenance strategy for maintaining flexible hoses on the SX MU pump diesel engines.

  The performance deficiency was determined to be more than minor because, if left uncorrected, the performance deficiency would have the potential to lead to a more significant safety concern since the failure of SX MU pump engine hoses could result in the inoperability of the SX MU pumps. The performance deficiency was also determined to be more than minor because the issue was associated with the Procedure Quality attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the reliability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage.) The finding screened as having very low safety significance because it did not result in a loss of operability or functionality. Specifically, the licensee reviewed the recent history of hose inspections and instances that required hose replacement and determined no failures had occurred that resulted in an inoperable condition. The inspectors did not identify a cross-cutting aspect associated with this finding because it was confirmed not to reflect current performance due to the age of the performance deficiency. (Section 1R07.1.b (3))

**Cornerstone: Barrier Integrity**

- Green. The inspectors identified a finding of very low safety significance and an associated NCV of TS 5.6.6, "Reactor Coolant System Pressure and Temperature Limits Report," when licensee personnel failed to maintain the analytical basis for deriving the Pressure Temperature Limit (PTL) curves consistent with the Unit 2 vessel head stud configuration. Specifically, the analytical model used in WCAP-16143, "Reactor Vessel Closure Head/Vessel Flange Requirements Evaluation for Byron/Braidwood Units 1 and 2," was based on the original closure head configuration and did not represent the modified closure head configuration (53 head studs) applicable to the Unit 2 reactor vessel. The licensee entered this issue into their CAP as IR 01578276, "Byron PTLR [Pressure Temperature Limits Report] Outside of NRC Approved Method."

  The performance deficiency was determined to be more than minor because it 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 (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accident or events. The inspectors also answered ‘Yes’ to the more-than-minor screening question, “If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?” Specifically, if left uncorrected, continued operation without a correct stress analysis to support the approved PTL curves could have allowed the reactor to operate at a pressure and temperature that increased the chance for a brittle fracture of the vessel under a pressurized thermal shock (PTS) event. The inspectors performed a Phase 1 SDP screening and selected the box under the Reactor Coolant System Boundary (e.g. PTS issues), which required a detailed risk evaluation. An NRC Region III senior reactor analyst performed a detailed risk evaluation of this finding. A potential increase in the probability for vessel failure would exist if the plant was operated in the unacceptable pressure-temperature regions and a PTS event occurred. Based on the licensee and supporting vendor assessments, which concluded that no substantial increase in vessel stresses will occur due to operation with 53 head studs, the driving force for crack propagation (e.g. $K_1$) remained essentially unchanged. However, to bound the risk evaluation, it was assumed that the initiating event frequency for a reactor vessel failure increased by 10 percent. From the Byron Standardized Plant Analysis Risk (SPAR) model, the initiating event frequency for reactor vessel failure from any cause was 1E-7/year. Core damage was expected to occur if reactor vessel failure occured. The exposure time for the finding was the maximum of 1 year. Thus, a bounding risk assessment yielded a delta risk of 1E-8/year. Therefore, based on the detailed risk evaluation, this finding was of very low safety significance (Green). This finding had a cross-cutting aspect in the Decision-Making component of the Human Performance cross-cutting area because the licensee did not use conservative assumptions in decision-making and adopt a requirement to demonstrate that a proposed action was safe in order to proceed. In this case, the licensee made a non-conservative assumption that the 10 CFR 50.59 process could be applied to authorize a change in the WCAP-16143 analysis, and therefore did not seek prior NRC approval (H.1(b)). (Section 1R18.1.b (1))

## B. Licensee-Identified Violations

None.

# REPORT DETAILS

## Summary of Plant Status

Unit 1 operated at or near full power during the entire inspection period except for planned maintenance activities.

Unit 2 operated at or near full power during the entire inspection period.

## 1. REACTOR SAFETY

**Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness**

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:

- Unit 1 Train ‘A’ Auxiliary Feedwater (AF) while Unit 1 Train ‘B’ AF was Out of Service for Planned Maintenance;
- Unit 2 Train ‘A’ Safety Injection During Planned Maintenance on Train ‘B’; and
- Unit 1 Train ‘B’ Containment Spray During Planned Maintenance on Train ‘A’.

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, 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 corrective action program (CAP) with the appropriate significance characterization. Documents reviewed are listed in the Attachment.

These activities constituted three partial system walkdown samples as defined in Inspection Procedures (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 availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- Fire Zone 11.4-0, Auxiliary Building General Area, Elevation 383;
- Fire Zone 11.5-0, Auxiliary Building General Area, Elevation 440; and
- Fire Zone 5.5-1, Unit 1 Auxiliary Equipment Room.

The inspectors reviewed these areas and determined whether 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. Using the documents listed in the Attachment, 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 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 three quarterly fire protection inspection samples as defined in IP 71111.05-05.

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07T)

.1 Triennial Review of Heat Sink Performance

a. Inspection Scope

The inspectors reviewed operability determinations, completed surveillances, vendor manual information, calculations, performance test results, and cooler inspection results associated with the Unit 0 Component Cooling Water (U-0 CCW) heat exchanger. This heat exchanger was chosen based on its risk significance in the licensee's probabilistic safety analysis, its important safety-related mitigating system support functions, its operating history, and its relatively low margin.

For the heat exchanger, the inspectors verified that testing, inspection, maintenance, and monitoring of biotic fouling and macrofouling programs were adequate to ensure proper heat transfer. This was accomplished by: (1) verifying that the test method used was consistent with accepted industry practices, or equivalent; (2) the test conditions were consistent with the selected methodology; (3) the test acceptance criteria was consistent with the design basis values; and (4) results of heat exchanger performance testing. The inspectors also verified that the test results appropriately considered differences between testing conditions and design conditions.

The inspectors verified the methods used to inspect and clean heat exchangers were consistent with as-found conditions identified and expected degradation trends and industry standards, the licensee's inspection and cleaning activities had established acceptance criteria consistent with industry standards, and the as-found results were recorded, evaluated, and appropriately dispositioned such that the as-left condition was acceptable.

In addition, the inspectors verified the condition and operation of the U-0 CCW heat exchanger was consistent with design assumptions in heat transfer calculations and as described in the Final Safety Analysis Report (FSAR). This included verification that the number of plugged tubes was within pre-established limits based on capacity and heat transfer assumptions. The inspectors verified the licensee evaluated the potential for water hammer and established adequate controls and operational limits to prevent heat exchanger degradation due to excessive flow-induced vibration during operation. In addition, eddy current test reports and visual inspection records were reviewed to determine the structural integrity of the heat exchanger.

The inspectors verified the performance of ultimate heat sink (UHS), safety-related service water systems, and their subcomponents such as piping, intake screens, pumps, valves, etc. by tests or other equivalent methods to ensure availability and accessibility to the inplant cooling water systems. The inspectors verified that the licensee's inspection of the UHS was comprehensive and of significant depth to ensure sufficient reservoir capacity. This included the review of licensee periodic monitoring and trending of sediment build-up and heat transfer capability. In addition, the inspectors reviewed the licensee's periodic performance monitoring of the UHS structural integrity and verified that adjacent non-seismic or nonsafety-related structures cannot degrade or block safety-related flow paths, during a severe weather or seismic event.

The inspectors performed a system walkdown of the service water and closed cooling water systems to verify the licensee's assessment of structural integrity. In addition, the inspectors reviewed available licensee testing and inspections results, licensee disposition of any active through-wall pipe leaks, and the history of through-wall pipe leakage to identify any adverse trends since the last NRC inspection. For closed cooling water systems, the inspectors reviewed operating logs and interviewed operators and the system engineer to identify adverse make-up trends that could be indicative of excessive leakage out of the closed systems. For buried or inaccessible piping, the inspectors reviewed the licensee's pipe testing, inspection, and/or monitoring program to verify structural integrity, and ensured that any leakage or degradation had been appropriately identified and dispositioned by the licensee. The inspectors verified that the periodic piping inspection program adequately detected and corrected protective coating failure, corrosion, and erosion. The inspectors verified that the licensee adequately monitored and resolved any adverse trends for deep draft vertical pumps by reviewing the operational history and inservice testing (IST) vibration monitoring results.

The inspectors performed a system walkdown of the essential service water (SX) intake structure and river screen house, to verify the licensee's assessment of structural integrity and component functionality. This included a verification that the licensee ensured proper functioning of traveling screens and strainers, SX makeup (MU) pumps, and structural integrity of component mounts. In addition, the inspectors verified that service water pump bay silt accumulation was monitored, trended, and maintained at an acceptable level by the licensee, and that water level instruments were functional and routinely monitored. The inspectors also verified the licensee's ability to ensure functionality during adverse weather conditions.

In addition, the inspectors reviewed IRs related to heat exchangers and heat sink performance issues to verify that the licensee had an appropriate threshold for identifying issues and to evaluate the effectiveness of their corrective actions. Documents reviewed are listed in the Attachment.

These inspection activities constituted two heat sink inspection samples as defined in IP 71111.07-05.

b. Findings

(1) Essential Service Water (SX) Blowdown Isolation Valves Not Tested

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XI, "Test Control," was identified by the inspectors when licensee personnel failed to demonstrate the ability to isolate the SX blowdown to the flume as credited in analyses described in the UFSAR. Specifically, the licensee failed to periodically test the active function of the blowdown isolation valves.

Description: The isolation capability of the SX blowdown to flume isolation valves (i.e., valves 0SX161A/B) was credited by the design basis of the plant during events that challenged the inventory of the safety-related cooling towers. These cooling towers were the site's UHS. Specifically, UFSAR 9.2.5.3.5, "Makeup and Minimum Basin Levels," stated that UHS inventory calculations assumed blowdown was isolated within 2 hours of an event that challenged this inventory. The inspectors confirmed that calculation NED-M-MSD-014, "Byron UHS Cooling Tower Basin Makeup Calculation," relied on this assumption to determine the initial cooling tower basin levels required to provide sufficient long-term cooling capability following postulated events. However, the licensee was not periodically testing the isolation capability of the SX blowdown to flume isolation valves to verify they would function consistent with this assumption.

The licensee entered this issue into their CAP as IR 1579361, "Valves 0SX161A/B Closure Not Functionally Tested." As an immediate action, the licensee established a reasonable expectation of operability by performing a historical review and determined valves 0SX161A/B were opportunistically cycled in 2008 and 2009 without incident during maintenance activities. In addition, these valves were not exposed to extreme environmental conditions. At the end of the inspection, the licensee also planned to perform a closing test of the valves, update the UFSAR active valve list, and add these valves to the IST program to periodically test their closing function.

Analysis: The inspectors determined the failure to demonstrate the ability to isolate the SX blowdown to the flume as credited in analyses and the UFSAR was contrary to 10 CFR 50, Appendix B, Criterion XI, “Test Control,” and was a performance deficiency.

The performance deficiency was determined to be more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone 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). Specifically, the failure to verify the SX blowdown to flume isolation capability did not ensure the UHS capability to meet its mitigating function consistent with the UFSAR described design analysis.

The inspectors determined the finding could be evaluated using the Significance Determination Process (SDP),” Attachment 0609.04, “Initial Characterization of Findings.” Because the finding impacted the Mitigating Systems cornerstone, the inspectors screened the finding using Inspection Manual Chapter (IMC) 0609, Appendix A, “The Significance Determination Process for Findings At-Power,” using Exhibit 2, “Mitigating Systems Screening Questions.” The finding screened as having very low safety significance (Green) because it did not result in a loss of operability or functionality. Specifically, the licensee reviewed recent history of the affected piping system and determined the blowdown valves were opportunistically cycled without incident.

The inspectors did not identify a cross-cutting aspect associated with this finding because it did not reflect current performance due to the age of the performance deficiency. Specifically, the design analysis credited the valves’ isolation capability in 1992; thus, the licensee was expected to reclassify their function as active at that time.

Enforcement: Title 10 CFR 50, Appendix B, Criterion XI, “Test Control,” requires, in part, that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components (SSCs) will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptable limits contained in applicable design documents.

Contrary to the above, as of October 31, 2013, the licensee failed to assure that testing required to demonstrate that SX blowdown to flume isolation valves would perform satisfactorily in service was identified and performed in accordance with written test procedures which incorporated the requirements and acceptance limits contained in applicable design documents. Specifically, the licensee failed to conduct tests that demonstrated the capability to isolate the SX blowdown to flume as credited in the UFSAR.

As an immediate action, the licensee established a reasonable expectation of operability by performing a historical review and determined valves 0SX161A/B were opportunistically cycled in 2008 and 2009 without incident during maintenance activities. At the end of the inspection, the licensee also planned to perform a closing test of the valves, update the UFSAR active valve list, and add these valves to the IST program to periodically test their closing function. Because this violation was of very low safety significance and was entered into the licensee’s CAP as IR 1579361, “Valves

0SX161A/B Closure Not Functionally Tested," this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy.
**(NCV 05000454/2013005-01; 05000455/2013005-01, Essential Service Water Blowdown Isolation Valves Were Not Tested)**.

(2) Intake Structure Silt Level Acceptance Criteria Were Non-Conservative

Introduction: A finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," was identified by the inspectors when licensee personnel failed to develop appropriate intake structure silt level acceptance criteria. Specifically, the licensee used a non-conservative river water low level value as an input when developing silt level acceptance criteria.

Description: In 1989 the NRC issued Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment," in response to operating experience related to service water systems, and requested licensees to supply information confirming the safety functions of their respective service water systems were met. In response, the licensee committed, in part, to develop river screen house and cooling tower basin inspection procedures. Thus, the licensee created procedure 0BMSR SX-5, "Inspection of River Screen House and Essential Service Water Cooling Tower Basins," which inspected the river screen house and essential service water cooling tower basins for silt buildup among other degradation mechanisms. The silt level acceptance criteria included in this procedure was developed through calculation BYR 96-277, "Determination of Maximum Allowable Silt Depth in River Screen House."

During this inspection period, the inspectors noted calculation BYR 96-277 used a low river level value of 665 feet as a design input. However, TS 3.7.9, "Ultimate Heat Sink," allowed a minimum river water level of 664.7 feet to maintain makeup pump operability. The inspectors were concerned because the use of the 665-feet value resulted in non-conservative acceptance criteria values for river screen house silt level, which could result in insufficient inventory for the makeup pumps to maintain adequate cooling tower basin level.

The licensee entered this issue into their CAP as IR 1582385, "Input Used in BYR 96-277 is Not Conservative." As an immediate corrective action, the licensee established a reasonable expectation of operability by confirming the river screen house was cleaned recently. At the end of the inspection, the licensee planned to revise the acceptance criteria and applicable procedures.

Analysis: The inspectors determined the failure to correctly develop intake structure silt level acceptance criteria was contrary to 10 CFR 50, Appendix B, Criterion III, "Design Control," and was a performance deficiency.

The performance deficiency was determined to be more than minor because it was associated with the Equipment Performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability of systems relied upon to respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, non-conservative acceptance criteria for silt accumulation at the intake structure did not ensure the availability, reliability, and capability of the UHS because it allowed a potentially inoperable condition to go undetected.

The inspectors determined the finding could be evaluated using the SDP, Attachment 0609.04, “Initial Characterization of Findings.” Because the finding impacted the Mitigating Systems cornerstone, the inspectors screened the finding using IMC 0609 Appendix A, “The Significance Determination Process for Findings At-Power,” using Exhibit 2, “Mitigating Systems Screening Questions.” The finding screened as having very low safety significance (Green) because it did not result in a loss of operability or functionality. Specifically, a historical review did not find an example where the as-found silt level resulted in an inoperable condition.

The inspectors did not identify a cross-cutting aspect associated with this finding because it was confirmed not to reflect current performance due to the age of the performance deficiency. Specifically, the silt level acceptance criteria were developed in 1996.

Enforcement: Title 10 CFR 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 are correctly translated into specifications, drawings, procedures, and instructions. A minimum river water level of 664.7 feet was required by TS 3.7.9 to maintain makeup pump operability.

Contrary to the above, as of November 7, 2013, the design control measures failed to translate the applicable design basis into specifications. Specifically, the licensee did not translate the minimum river water level value required by TS 3.7.9 into calculation BYR 96-277 resulting in non-conservative silt level acceptance criteria. As an immediate corrective action, the licensee established a reasonable expectation of operability by confirming the river screen house was recently cleaned. At the end of the inspection, the licensee planned to revise the acceptance criteria and applicable procedures. Because this violation was of very low safety significance and was entered into the licensee’s CAP as IR 1582385, “Input Used in BYR 96-277 is Not Conservative,” this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000454/2013005-02; 05000455/2013005-02, Intake Structure Silt Level Acceptance Criteria Were Non-Conservative)**.

(3) Failure to Implement Preventive Maintenance Procedure Replacement Schedules for Essential Service Water Makeup Pump Diesel Engine Hoses

Introduction: A finding of very low safety significance (Green) and an associated NCV of TS 5.4.1, “Procedures,” was identified when licensee personnel failed to establish and implement preventive maintenance schedules as required by Regulatory Guide 1.33. Specifically, the licensee failed to have adequate procedures that incorporated preventive maintenance schedules for the replacement of SX Makeup (MU) pump diesel engine hoses in accordance with vendor recommendations and Exelon Corporate Performance Centered Maintenance (PCM) templates.

Description: During this inspection period, inspectors performed a walkdown of the Division 1 and Division 2 SX MU pump diesels with licensee personnel. The inspectors noted significant differences regarding the age of hoses installed on the Division 2 SX MU pump diesel, 0SX01PB. The inspectors requested and reviewed documents related to the licensee’s preventive maintenance program addressing the inspection and replacement of rubber hoses, both with and without the external metallic braiding installed on each of the SX MU pump diesels.

The inspectors reviewed WO 01395853, "Essential Service Water Makeup Pump Support 0BVSR," dated May 9, 2012, which contained steps to inspect and replace hoses installed on the SX MU pump diesel based on their condition. The inspectors noted the inspection procedure contained in the WO lacked specific guidance for inspecting rubber hoses with metallic braided covers. The inspectors also noted the procedures failed to include acceptance criteria for accepting or rejecting the condition of the rubber that was covered by the outer metallic braided cover.

The inspectors reviewed the SX MU pump diesel vendor manual and the PCM template for small diesel engines and noted that each of these documents recommended specific replacement schedules for hoses installed on the SX MU pump diesel engine. The inspectors noted the vendor manual recommended a 5-year replacement schedule and the corporate PCM template, which was revised following a 2003 MPR Technical Evaluation, included a maximum 12-year replacement schedule for flexible hoses.

The inspectors were concerned because the metallic braiding was a barrier that could prevent a reasonable inspection to assess the condition of the hose. Without acceptance criteria for these inspections, or a required replacement schedule, hose degradation could go unidentified and lead to the failure of critical equipment.

Due to the inspector's questioning, the licensee determined the last replacement date of the approximately 20 hoses on each diesel (19 and 24, specifically for 0SX01PA and 0SX01PB respectively) was unknown.

The licensee entered this issue into their CAP as IR 01582656, "NRC ID [Identified] Vendor Manual Recommendation Not Being Implemented," and 01590368, "NRC ID – PCM Template/Vendor Manual Recommendation." As an immediate action, the licensee established a reasonable expectation of operability by reviewing the inspection history and verifying no IRs had been generated during these inspections. At the end of the inspection, the licensee planned to evaluate the current maintenance strategy for maintaining flexible hoses on the SX MU pump diesel engines.

Analysis: The inspectors determined the failure to establish and implement a preventive maintenance schedule to replace hoses on SX MU pump diesel engines was contrary to TS 5.4.1, "Procedures," and was a performance deficiency.

The performance deficiency was determined to be more than minor because, if left uncorrected, the failure of SX MU pump engine hoses could result in the inoperability of the SX MU pumps. The performance deficiency also screened as more than minor because it affected the Procedure Quality attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the reliability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). Specifically, failing to implement preventive maintenance procedures that required periodic replacement of hoses on pre-established schedules could allow hose degradation to remain unidentified, and therefore allow a potentially inoperable condition to go undetected.

The inspectors determined the finding could be evaluated using the SDP, Attachment 0609.04, "Initial Characterization of Findings." Because the finding impacted the Mitigating Systems cornerstone, the inspectors screened the finding using IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," using

Exhibit 2, “Mitigating Systems Screening Questions.” The finding screened as having very low safety significance (Green) because it did not result in the loss of operability or functionality.

The inspectors did not identify a cross-cutting aspect associated with this finding because it was confirmed not to reflect current performance due to the age of the performance deficiency. Specifically, the 18-month prime mover inspection had existed since 1987, long before the PCM template recommendation.

Enforcement: Technical Specification 5.4.1 states, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Regulatory Guide 1.33, Revision 2, Appendix A, dated February 1978. Regulatory Guide 1.33, Appendix A, Section 9.b, “Procedures for Performing Maintenance,” states, in part, that preventive maintenance schedules should be developed to specify… inspection or replacement of parts that have a specific lifetime such as wear rings. The vendor manual recommendation and Corporate PCM Template for small diesel engines, which included the SX MU pump diesel engine, required replacement of fuel oil and miscellaneous hoses on a recommended schedule.

Contrary to the above, since the implementation of the prime mover inspection in 1987, the licensee did not implement a procedure incorporating a preventive maintenance schedule which specified replacement of the SX MU pump diesel engine hoses that had a specific recommended lifetime.

As an immediate action, the licensee established a reasonable expectation of operability by reviewing the inspection history and verifying no IRs had been generated during these inspections. At the end of the inspection, the licensee planned to evaluate the current maintenance strategy for maintaining flexible hoses on the SX MU pump diesel engines. Because this violation was of very low safety significance and was entered into the licensee’s CAP as IR 01582656, “NRC ID Vendor Manual Recommendation Not Being Implemented,” and 01590368, “NRC ID – PCM Template/Vendor Manual Recommendation,” this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000454/2013005-03; 05000455/2013005-03, Failure to Implement Preventive Maintenance Procedure Replacement Schedules for Essential Service Water Makeup Pump Diesel Engine Hoses).**

1R11 Licensed Operator Requalification Program (71111.11)

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

a. Inspection Scope

On November 15, 2013, the inspectors observed a crew of licensed operators in the plant’s simulator during licensed operator requalification training to verify that operator performance was adequate, evaluators were identifying and documenting crew performance problems, and training was being conducted in accordance with licensee procedures. The inspectors evaluated the following areas:

- licensed operator performance;
- crew’s clarity and formality of communications;
- 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 ability to identify and implement appropriate TS actions and Emergency Plan actions and notifications.

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

This inspection constituted one quarterly licensed operator requalification program simulator sample as defined in IP 71111.11-05 and satisfied the inspection program requirement for the resident inspectors to observe a portion of an in-progress annual requalification operating test during a training cycle in which it was not observed by the NRC during the biennial portion of this IP.

b. Findings

No findings were identified.

.2 Resident Inspector Quarterly Observation of Heightened Activity or Risk (71111.11Q)

a. Inspection Scope

On November 23, 2013, the inspectors observed Unit 1 control room operators maneuvering power from 100 percent to 76 percent in support of planned maintenance activities. This was an activity that required heightened awareness or was related to increased risk. The inspectors evaluated the following areas:

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

The performance in these areas was compared to pre-established operator action expectations, procedural compliance and successful critical task completion requirements. Documents reviewed are listed in the Attachment.

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

b. Findings

No findings were identified.

.3 Biennial Written and Annual Operating Test Results (71111.11A)

a. Inspection Scope

The inspector reviewed the overall pass/fail results of the Annual Operating Test administered by the licensee from October 16 - December 6, 2013 as required by 10 CFR 55.59(a). The results were compared to the thresholds established in IMC 0609, Appendix I, "Licensed Operator Requalification Significance Determination Process," to assess the overall adequacy of the licensee's Licensed Operator Requalification Training (LORT) Program to meet the requirements of 10 CFR 55.59.

This inspection constitutes one annual licensed operator requalification inspection 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 systems:

- SX MU Pump and Auxiliaries;
- Control Rod Drive; and
- Boric Acid.

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 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. Documents reviewed are listed in the Attachment.

This inspection constituted three 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 prior to removing equipment for work:

- Unit 2 Risk Following the Emergent Failure of a Rod Control Card;
- Unit 0 Risk Due to Changes in Planned Work and the Emergent Failure of 0C Auxiliary Building Heating, Ventilation, and Air Conditioning (HVAC) Supply Fan; and
- Unit 1 Risk During Planned Work on Containment Spray Train 'A'.

These activities were selected based on their potential risk significance relative to the Reactor Safety Cornerstones. As applicable for each activity, 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 shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met. Documents reviewed are listed in the Attachment.

These maintenance risk assessments and emergent work control activities constituted three 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:

- Nonsafety-Related Gaskets Installed in Safety-Related Air-Operated Valves;
- Unit 2 Reactor Vessel Head Bearing Stress Above ASME Allowable Values;
- Emergency Diesel Generator 2B Tripped During Cooldown Cycle;
- AF Pump Suction Concerns; and
- UHS Capability With Loss of SX Cooling Tower Fans.

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, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the Attachment.

This operability inspection constituted five samples as defined in IP 71111.15-05.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18)

.1 Plant Modifications

a. Inspection Scope

The inspectors reviewed the following plant modification:

- Engineering Change (EC) 379850, "Operation of Reactor Vessel With One Out-of-Service Closure Stud".

Engineering Change 379850, "Operation of Reactor Vessel with One Out-of-Service Closure Stud," identified that in 2010, Unit 2 reactor vessel closure head stud number 11 stuck (bound up) during the process to remove (e.g. unthread) the stud from the vessel flange. The stuck head stud was unthreaded about 4 inches above fully seated and the licensee elected to cut off and remove the top portion of this stud at 19.25 inches above the vessel flange face to prevent interference with head re-assembly (stud tensioning equipment). In EC 379850, the licensee evaluated and accepted this revised head configuration with head stud number 11 removed from service.

The inspectors reviewed the configuration changes and associated 10 CFR 50.59 safety evaluation screenings against the design basis, the UFSAR, and the TS, as applicable, to verify that the modification did not affect the operability or availability of the affected system. The inspectors, as applicable, observed ongoing and completed work activities to ensure that the modifications were installed as directed and consistent with the design control documents; the modifications operated as expected; post-modification testing adequately demonstrated continued system operability, availability, and reliability; and that operation of the modifications did not impact the operability of any interfacing systems. As applicable, 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. Documents reviewed are listed in the Attachment.

The findings discussed in the following section address this modification.

This inspection constituted one permanent plant modification sample as defined in IP 71111.18-05.

b. Findings

(1) Analytical Basis for Pressure Temperature Limits Curves Not Maintained Consistent with the Unit 2 Vessel Head Stud Configuration

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of TS 5.6.6 when licensee personnel failed to maintain the analytical basis for deriving the pressure temperature limits (PTL) curves consistent with the Unit 2 vessel head stud configuration. Specifically, the analytical model used in WCAP-16143, "Reactor Vessel Closure Head/Vessel Flange Requirements Evaluation for Byron/Braidwood Units 1 and 2," was based on the original closure head configuration and did not represent the modified closure head configuration (53 head studs) applicable to the Unit 2 reactor vessel.

Description: On October 29, 2013, the inspectors identified that the licensee failed to maintain the Unit 2 vessel head studs in a configuration consistent with the NRC approved analytical model used to derive the PTL for operation of the reactor vessel. The inspectors were concerned that changes from the operating stress distributions with 53 head studs could result in non-conservative PTL curves and result in operation of the vessel in an unacceptable region during heatup or cooldown. Operation in this unacceptable region could increase the possibility of vessel failure during a PTS event.

On May 7, 2010, the licensee returned Unit 2 to operation with 53 head studs in-service with the remnant head stud number 11 abandoned in place. In WCAP-16143, "Reactor Vessel Closure Head/Vessel Flange Requirements Evaluation for Byron/Braidwood Units 1 and 2," Section 4, "Flange Integrity," and in Appendix C of WCAP-16143, vessel safety margins were demonstrated based upon an analytical model representative of the original closure head configuration. Operation of Unit 2 with 53 closure head studs was not within the bounds and limitations of this analysis and what the NRC had previously reviewed and found acceptable. Because the NRC had not reviewed and approved an alternative stress analysis with 53 head studs, the licensee was not in compliance with TS 5.6.6, “Reactor Coolant System (RCS) Pressure and Temperature Limits Report (PTLR).”

The licensee completed Operability Evaluation 13-009 and concluded that plant operation with 53 studs did not impact the methodology used in WCAP-16143 based upon engineering judgment documented in a supporting letter from the vendor (Westinghouse). The Westinghouse vendor letter, dated August 27, 2013, documented that the vessel stress components evaluated near the head flange in WCAP-16143 would remain essentially unchanged and that the PTL for the vessel established in the current PTLR remained valid. The licensee’s failure to submit a revision to WCAP-16143 for NRC approval stemmed from the licensee staff belief that the 10 CFR 50.59 regulation applied to this document. Specifically, the licensee staff had interpreted NRC guidance provided in Generic Letter 96-03, “Relocation of the Pressure Temperature Limit Curves and Low Temperature Overpressure Protection System Limits,” as authorizing the application of the 10 CFR 50.59 rules to revise this analysis. However, the WCAP-16143 analysis was approved under the 10 CFR 50.12 exemption process and 10 CFR 50.59 rules cannot be applied to this regulation. Specifically, 10 CFR 50.59(c)4 stated, in part, that the provisions in this section did not apply to changes to the facility when the applicable regulations established more specific criteria for accomplishing such changes. Further, the NRC endorsed guidance for implementing 10 CFR 50.59 (NEI 96-07 Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments - Section 4.1.1) identified the 10 CFR 50.12 rule in the list of regulations to which the 10 CFR 50.59 regulation may not be applied. The licensee subsequently entered this issue into their CAP as IR 01578276, “Byron PTLR Outside of NRC Approved Method.”

<u>Analysis</u>: The inspectors determined that the failure to maintain the analytical basis for deriving the PTL curves consistent with the Unit 2 vessel head stud configuration was contrary to TS 5.6.6.b and was a performance deficiency. Specifically, operation of Unit 2 with 53 closure head studs was outside the NRC approved analysis for development of the PTL curves (WCAP-16143).

The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, “Issue Screening,” dated September 7, 2012, because it 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 (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accident or events. The inspectors also answered ‘Yes’ to the more-than-minor screening question, “If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?” Specifically, if left uncorrected, continued operation without a correct stress analysis to support the approved PTL curves could have allowed the reactor to operate at a pressure and temperature that increased the chance for a brittle fracture of the vessel in a PTS event. The inspectors performed a Phase 1 SDP screening using IMC 0609, Attachment 0609, Appendix A, Exhibit 3, “Barrier Integrity Screening Questions,” dated June 19, 2012, and selected the box under the RCS Boundary (e.g. PTS issues) which required a detailed risk evaluation.

An NRC Region III senior reactor analyst performed a detailed risk evaluation of this finding. A potential increase in the probability for vessel failure would exist if the plant was operated in the unacceptable pressure-temperature region and a PTS event occurred. Based on the licensee and supporting vendor assessments, which concluded that no substantial increase in vessel stresses would occur when operating with 53 head studs, the driving force for crack propagation (e.g. $K_1$) remained essentially unchanged. However, to bound the delta risk evaluation, it was assumed that the initiating event frequency for a reactor vessel failure increased by 10 percent. From the Byron Standardized Plant Analysis Risk (SPAR) model version 8.21, the initiating event frequency for reactor vessel failure from any cause was 1E-7/year. Core damage was expected to occur if reactor vessel failure occurred. The exposure time for the finding was the maximum of 1 year. Thus, a bounding risk assessment yielded a delta risk of 1E-8/year. Therefore, based on the detailed risk evaluation, this finding was of very low safety significance (Green).

This finding had a cross-cutting aspect in the Decision-Making component of the Human Performance cross-cutting area because the licensee did not use conservative assumptions in decision-making and adopt a requirement to demonstrate that the proposed action was safe in order to proceed. In this case, the licensee staff made a non-conservative assumption that the 10 CFR 50.59 process could be applied to authorize a change in the WCAP-16143 analysis and did not seek prior NRC approval. Without NRC intervention, the licensee's engineering staff would not have recognized the need to obtain prior NRC approval for changes made to WCAP-16143, and therefore the finding reflected current performance (H.1(b)).

Enforcement: Technical Specification 5.6.6, "RCS PTLR," Step "b" stated in part, "The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:…3. Westinghouse WCAP-16143, "Reactor Closure Head/Vessel Flange Requirements Evaluation for Byron/Braidwood Units 1 and 2."

Contrary to the above, from May 7, 2010 through October 31, 2013, the licensee did not use the analytical methods to determine the RCS PTL that were previously reviewed and approved by the NRC and instead for the Unit 2 vessel relied on Operability Evaluation 13-009, which did not contain an NRC approved methodology. Specifically, in Operability Evaluation 13-009, the licensee relied upon engineering judgment based upon a supporting vendor letter, which did not represent an NRC-approved methodology. Because this violation was of very low safety significance and was entered into the licensee's CAP as IR 01578276, "Byron PTLR Outside of NRC Approved Method," this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000455/2013005-04, Analytical Basis For PTL Curves Not Maintained Consistent with the Unit 2 Vessel Head Stud Configuration)**.

(2) Reactor Vessel Design Documents Not Updated to Reflect Unit 2 Missing Head Stud

Introduction: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to maintain reactor vessel design specifications and analyses up-to-date for the 53 stud vessel head configuration applicable to Unit 2. Specifically, the reactor vessel Design Specification and Design Analysis did not reflect the modified and stuck head stud number 11.

Description: On October 29, 2013, the inspectors identified that the licensee failed to maintain the Unit 2 reactor vessel design specification and analysis up to date to reflect the modified and stuck stud number 11. The inspectors were concerned that the failure to update these key design documents caused them to be inaccurate, and if these documents were subsequently relied on for future design changes, the vessel design may not be adequate to meet the design basis events resulting in a loss-of-coolant-accident (LOCA).

In EC 379850, "Operation of Reactor Vessel with One Out-of-Service Head Stud," the licensee evaluated and accepted this revised head configuration with head stud number 11 removed from service. However, the inspectors identified several design basis documents that were not updated to reflect the changes authorized by the licensee in EC 379850. For example:

- Certified Design Specification 676413, "Reactor Vessel," Revision 6, Section 3.3.2.9, stated, "Each stud, nut and washer shall be functionally interchangeable in all stud, nut and washer assemblies; and each stud, nut and washer assembly shall be functionally interchangeable in all threaded stud holes." This statement was no longer accurate for the remnant stud and stud hole at the head stud number 11 position.

- Certified Design Specification 676413, Section 3.3.4.3, stated, "A lifting eye shall be provided for each stud," and Section 3.3.4.4 stated, "Each stud shall have a machined hexagon on the top." Neither of these descriptions was applicable to remnant head stud number 11.

- Certified Design Analysis – Contract 640-0012-51/52, "Closure Analysis," Revision 2, did reflect the increased maximum membrane stress in the remaining Unit 2 closure head studs adjacent to stud hole number 11. Further, this analysis was not updated with the changes in vessel stud elongations caused by the reduction to 53 in-service closure head studs.

- Certified Design Analysis – Contract 640-0012-51/52, "173," I.D. Reactor Vessel Appendix G Calculations, were no longer valid as this information had been superseded by the revised methodology for deriving the PTL curves identified in WCAP-16143.

Older Section XI Editions (e.g. 1995 Edition) did not explicitly require updating the original design documents when modifying the ASME Code components. However, the licensee adopted the 2001 Edition through 2003 Addenda of the ASME Section XI Code on January 16, 2006, which included a specific requirement to ensure the original design documents reflected the modifications that were made. EC 379850 referenced the reactor vessel Design Specifications and Analysis, but these documents were not updated to reflect the changes made to the Unit 2 closure head. Some members of the licensee staff were not aware of the ASME Code Section XI requirement to update the original component design information and stated that the site and corporate design program procedures did not include a requirement to update the original design or analysis documents. These individuals had misinterpreted the procedural requirement and did not apply the procedure correctly. Given the programmatic nature of the licensee's error, the scope of inaccurate original design documents was potentially more extensive than the examples identified herein. The licensee subsequently entered this issue into their CAP as IR 01578285, "Design Documentation is Not in Compliance with ASME."

<u>Analysis</u>: The inspectors determined that failure to maintain reactor vessel design specifications and analyses up-to-date for the 53 stud vessel head configuration applicable to Unit 2 was contrary to 10 CFR 50, Appendix B, Criterion III, "Design Control," and was a performance deficiency.

The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it was associated with the Design Control attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions. The inspectors also answered 'Yes' to the more-than-minor screening question, "If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, the inspectors determined that this issue was more than minor because, if left uncorrected, the failure to maintain the Unit 2 reactor vessel design specifications and analyses caused them to be inaccurate and if these documents were subsequently relied on for future design changes, the vessel design may not be adequate to maintain structural integrity during design basis events resulting in a LOCA. The inspectors performed a Phase 1 SDP screening using IMC 0609, Attachment 0609, Appendix A, Exhibit 1- Initiating Events Screening Questions, dated June 19, 2012, and evaluated this issue by application of Questions 1 and 2. Questions 1 and 2 asked, "If after a reasonable assessment of degradation, could the finding result in exceeding the RCS leak rate for a small LOCA or could the finding have likely affected other systems used to mitigate a LOCA resulting in a total loss of their function (e.g., Interfacing System LOCA)?" In this case, the degradation prompting the reduction in the number of head studs and the licensee's failure to maintain the design analysis had not yet affected the ability of the reactor vessel to perform its design functions so the inspector answered these questions 'No,' and this issue screened as having very low safety significance (Green).

The inspectors reviewed other ASME Class 1 modification documentation packages executed since this modification was processed and determined that the appropriate changes were made to the design bases documents in accordance with the committed code standard.

The inspectors determined that this issue was not indicative of current performance and therefore no cross-cutting aspect was assigned.

<u>Enforcement</u>: Title 10 CFR 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, as defined in 10 CFR 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions.

Section XI, IWA-4311, “Material, Design or Configuration Changes,” step (e), stated that changes made to material, design, or configuration shall be documented in revisions to existing reports, records, and specification, or in a separate evaluation or update traceable to and from the original record or report. Section XI, IWA-4311, step (e) also requires that the following records shall be maintained current with respect to the item’s design and configuration: (1) Design Specification, (2) Design Report or analysis that demonstrates compliance with the Construction Code or the Owner’s Requirements, and (3) Overpressure Protection Report.

Contrary to the above, from May 7, 2010 through October 31, 2013, Certified Design Specification 676413, “Reactor Vessel,” Revision 6 and Certified Design Analysis – Contract 640-0012-51/52, “Closure Analysis,” Revision 2 and the “173” I.D. Reactor Vessel Appendix G Calculations, had not been updated and maintained current to reflect the revised Unit 2 vessel configuration and PTL curve methodology identified in WCAP-16143. Because this violation was of very low safety significance and was entered into the licensee’s CAP as IR 01578285, “Design Documentation is Not in Compliance with ASME,” this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000455/2013005-05, Reactor Vessel Design Documents Not Updated to Reflect Unit 2 Missing Head Stud)**.

(3) <u>Corrosion Effects on the Unit 2 Reactor Vessel Flange Not Monitored</u>

<u>Introduction</u>: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion XI, “Test Control,” when licensee personnel failed to establish a program to monitor the corrosion effects on the reactor vessel flange integrity caused by the ingress of borated water below the abandoned head stud number 11.

<u>Description</u>: On October 29, 2013, the inspectors identified that the licensee failed to establish a program to monitor the corrosion effects on the reactor vessel flange integrity caused by the ingress of borated water below the abandoned head stud number 11. The inspectors were concerned that the failure to adequately monitor the long-term boric acid corrosion effects on the vessel flange could result in wastage or pressure induced cracking of the flange that affected the joint tight integrity of the reactor head-to-vessel-flange joint resulting in a LOCA.

In EC 379850, the licensee accepted the revised Unit 2 head configuration with head stud number 11 removed from service and included an assessment of the effects on the vessel closure flange from boric acid corrosion. By design, a cavity exists under a fully seated closure stud (approximately 4-inch depth). With the Unit 2 stud number 11 partially unthreaded, the licensee estimated that this cavity was 8 inches in height and about 7 inches in diameter. This cavity was subject to filling with borated water during refueling when the refueling cavity was flooded up above the vessel flange level. Specifically, borated water would enter the cavity through the 1-inch diameter hole bored through the center of the stud. The bottom of this 1-inch stud bore hole also contained a threaded plug with a 1/16-inch diameter drilled hole which provided a direct path for water to fill the stud flange cavity. The licensee analysis evaluated the corrosion effects on the flange in this cavity that occurred during refueling and as the water boiled off during subsequent heatup to normal operating conditions. The licensee also assumed that the pressure induced by heating and boiling of the water trapped in this cavity would be vented through the 1/16-inch diameter plug hole at the bottom of the stud bore hole.

However, the licensee's corrosion assessment in EC 379850 did not adequately evaluate the boric acid corrosion effects, nor fully consider the potential for pressure buildup that could affect the reactor vessel flange integrity. For example, in:

- EC 379850, Section 4.1.33, the licensee assumed 10 hours of boiling would occur during which the corrosion rates could be as high as 1 inch per year. If the time to boil was longer than 10 hours, the flange corrosion wastage would be greater. However, the licensee could not provide a basis for the length of time (10 hours) assumed to boil off the trapped boric acid below stud number 11.

- EC 379850, Section 4.1.33, the licensee stated, "Therefore, for the majority of the operating cycle, the stud hole will be exposed to dry boric acid crystals at high temperature, which have a negligible corrosion rate." The licensee failed to recognize that hydrated boric acid would melt at about 380 degrees Fahrenheit (F) and did not evaluate the corrosion rates for the resultant molten boric acid. Molten boric acid may have contributed to the degradation observed for the Davis-Besse reactor vessel head corrosion cavity event as discussed in Appendix B of NUREG CR 6923, "Expert Panel Report on Proactive Materials Degradation Assessment."

- EC 379850, Section 4.1.33, the licensee stated, "Water trapped underneath the stud will expand as the vessel heats up. If the region were completely water solid, the relative incompressibility of water would cause significant pressure increases. However, the small hole drilled through the plug in the bottom of the stud central hole would readily relieve pressure increase." As stated above, the licensee staff did not recognize that the boric acid deposits remaining inside the 1-inch stud bore hole would melt at normal operating temperature. The molten boric acid is a viscous fluid that would tend to collect above the plug and block the plug vent hole. After a reactor cooldown, the molten boric acid remaining at the bottom of the stud bore hole would solidify and block the small diameter plug hole. Because the cavity below stud 11 would be subject to water refill through the gaps in the stud-to-flange threaded joint, the cavity could refill and then a subsequent vessel heatup would potentially create a water pocket without an adequate vent path. If this scenario occurred, high pressures would be created that may tear or crack the vessel flange near stud number 11.

- EC 379850, Section 4.1.33, the licensee stated, "To ensure that excessive corrosion of the vessel flange does not occur in future cycles with the out-of-service stud installed, controls will be established to monitor, mitigate or prevent additional corrosion." As of October 31, 2013, the licensee had not implemented controls to monitor or prevent additional flange corrosion (reference IR 01571012). The controls considered by the licensee staff, but not implemented, included a welded plug installed at the top of the stud bore hole.

- EC 379850, Section 4.1.27, the licensee stated, "The threaded portion of the reactor vessel flange containing the stuck stud will also be rendered inaccessible; however, there is no ISI [Inservice Inspection] requirement to inspect the vessel flange threads." This statement appeared to be incorrect, because the ASME Code Section XI, Table IWB-2500, Item B6.40, required a volumetric inspection of the flange around the threaded area. If the licensee discontinued this inspection, it would require NRC approval in accordance with 10 CFR 50.55a.

Based on the uncertainty in the corrosion analysis to estimate the boric acid corrosion induced wastage rate as discussed above, demonstration of continued vessel flange integrity would rely on effective controls to monitor, mitigate, or prevent additional corrosion and these controls had not been implemented. Therefore, the inspectors had a concern with the long-term integrity of the vessel flange if boric acid corrosion/wastage was allowed to progress without adequate monitoring or mitigation. The inspectors determined that boric acid corrosion rates would not result in substantive wastage in the short-term that would be sufficient to challenge flange integrity. Additionally, the amount of boric acid deposits in the short-term would not likely be sufficient to prevent the venting of the water cavity below the bolt hole as it boiled off. The licensee entered these issues into their CAP as IR 01578289, "EC 379850 Failed to Adequately Evaluate Boron Corrosion."

Analysis: The inspectors determined that the failure to adequately evaluate the long-term corrosion effects on the reactor vessel flange integrity caused by the ingress of borated water below the abandoned head stud number 11 was contrary to 10 CFR 50, Appendix B, Criterion XI, "Test Control," and was a performance deficiency.

The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it adversely affected the Design Control attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions. The inspectors also answered 'Yes' to the more-than-minor screening question, "If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, the inspectors determined that this issue was more than minor because, if left uncorrected, the failure to adequately evaluate the long-term corrosion effects on the reactor vessel flange integrity could result in a LOCA. The inspectors performed a Phase 1 SDP screening using IMC 0609, Attachment 0609, Appendix A, Exhibit 1 - Initiating Events Screening Questions, dated June 19, 2012, and evaluated this issue by application of Questions 1 and 2. Questions 1 and 2 asked, "If after a reasonable assessment of degradation, could the finding result in exceeding the RCS leak rate for a small LOCA or could the finding have likely affected other systems used to mitigate a LOCA resulting in a total loss of their function (e.g., Interfacing System LOCA)?" In this case, the degradation had not yet progressed to the point that would impact the vessel flange integrity so the inspector answered these questions 'No,' and this issue screened as having very low safety significance (Green).

This finding has a cross-cutting aspect in the CAP component of the Problem Identification and Resolution cross-cutting area because the licensee did not take appropriate corrective actions to address safety issues and adverse trends in a timely manner, commensurate with their safety significance and complexity. Specifically, the licensee failed to develop a procedure for monitoring the boric acid corrosion induced wastage of the vessel head flange as a corrective action resulting from the review of EC 379850 (reference IR 01061307 - Actions Associated with EC 379850) (P.1(d)).

Enforcement: Title 10 CFR 50, Appendix B, Criterion XI, "Test Control," requires, in part, that a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents. The test program shall include, as appropriate, proof tests prior to installation, preoperational tests, and operational tests during nuclear power plant or fuel reprocessing plant operation, of structures, systems, and components. Test procedures shall include provisions for assuring that all prerequisites for the given test have been met, that adequate test instrumentation is available and used, and that the test is performed under suitable environmental conditions. Test results shall be documented and evaluated to assure that test requirements have been satisfied.

Contrary to the above, from May 7, 2010 through October 31, 2013, the licensee failed to establish a test program to demonstrate through a written test procedure that the integrity of a component (reactor vessel flange) subject to boric acid corrosion would perform satisfactorily in service. Because this violation was of very low safety significance and was entered into the licensee's CAP as IR 01578289, "EC 379850 Failed to Adequately Evaluate Boron Corrosion," this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000455/2013005-06, Corrosion Effects on the Unit 2 Reactor Vessel Not Monitored)**.

(4) <u>Inadequate Reactor Vessel Stress Analysis for Unit 2 Missing Head Stud</u>

<u>Introduction</u>: The inspectors identified a finding of very low safety significance (Green) and an associated NCV of 10 CFR 50, Appendix B, Criterion III, "Design Control," when licensee personnel failed to perform an adequate thermal-mechanical analysis to support operation with a missing Unit 2 head stud. Specifically, the licensee failed to perform a complete set of analyses under operating, faulted, and design conditions to confirm the associated stud and flange stresses remained within the Code allowable limits. Consequently, the licensee did not recognize that the bearing stress under the head stud nuts at the vessel flange face exceeded the Code allowable stress.

<u>Description</u>: On October 30, 2013, the inspectors identified that the licensee failed to perform an adequate thermal-mechanical analysis to support operation with a missing Unit 2 head stud. Specifically, the licensee had not performed a complete set of analyses under operating, faulted, and design conditions to confirm the associated stud and flange stresses remained within the Code allowable limits. Consequently, the licensee did not recognize that the bearing stress under the head stud nuts at the vessel flange face exceeded the Code allowable stress. The inspectors were concerned that because the estimated stress exceeded the material yield stress, local plastic deformation would occur in the flange joint and cause the reactor head-to-vessel-flange joint to leak under stress induced by a heatup transient resulting in a LOCA.

In EC 379850, "Operation of Reactor Vessel With One Out-of-Service Closure Stud," the licensee evaluated and accepted the Unit 2 revised head configuration with head stud number 11 removed from service based upon supporting vendor (Westinghouse) calculation EDRE-EMT-1110, " Engineering Report for the Evaluation of an Out of Service Closure Stud in Byron Unit 2 Reactor Vessel," Revision 0. However, the scope of this calculation included only the maximum stud membrane stress under the limiting operating transient (vessel heatup) and did not included calculations of stud or flange stresses under the limiting faulted and design transient conditions. The licensee believed that due to the large margins available in the original analysis, that specific calculations did not need to be re-performed to demonstrate that the vessel stud stresses would meet Code allowable stresses under the faulted and design conditions.

The inspectors also identified that the scope of calculation EDRE-EMT-1110 did not include a review of the increase in the bearing and interface stress loads on the vessel flange faces under the limiting normal operating transients (heatup or cooldown). The inspectors performed a simplified calculation of the bearing stress under the stud nut at the vessel flange locations adjacent to stud number 11 and determined that the maximum bearing stress under these stud nut locations at the vessel flange would exceed the ASME Code Section III allowable stress value $S_y$ (yield stress) = 45.0 kilo-pounds per square inch (ksi) at normal operating temperature. The licensee and their vendor staff (Westinghouse) subsequently performed informal calculations and determined a 46.1 ksi stress would be present at the flange surface under the studs adjacent to stud hole number 11. The licensee performed an immediate operability evaluation and based upon engineering judgment concluded the Unit 2 vessel was operable because the Certified Material Test Report for the vessel flange material demonstrated a measured yield stress ($S_y$ ) of 62.7 ksi. The 62.7 ksi value was the flange material yield strength as measured at room temperature, and the Code allowable stress for this material at room temperature was 50 ksi. Based on the additional measured yield strength margin available above the Code design value, the inspectors agreed with the licensee's basis for operability. The licensee entered this issue into their CAP as IR 01578717, "Unit 2 RV [Reactor Vessel] Closure Stud Bearing Stress is Above ASME Allowed."

<u>Analysis</u>: The inspectors determined that the failure to perform an adequate thermal-mechanical analysis to support operation with a missing Unit 2 head stud was contrary to 10 CFR 50, Appendix B, Criterion III, "Design Control," and was a performance deficiency.

The inspectors determined that this issue was more than minor in accordance with IMC 0612, Appendix B, "Issue Screening," dated September 7, 2012, because it was associated with the Design Control attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions. The inspectors also answered 'Yes' to the more-than-minor screening question, "If left uncorrected, would the performance deficiency have the potential to lead to a more significant safety concern?" Specifically, the inspectors determined that this issue was more than minor because, if left uncorrected, the failure to perform an adequate thermal-mechanical analysis could result in the inability of the reactor vessel to meet the design basis operating transient without a LOCA. The inspectors performed a Phase 1 SDP screening using IMC 0609, Attachment 0609, Appendix A, Exhibit 1 - Initiating Events Screening Questions, dated June 19, 2012, and evaluated this issue by application of Questions 1 and 2. Questions 1 and 2 asked, "If after a reasonable assessment of degradation, could the finding result in exceeding the RCS leak rate for a small LOCA or could the finding have likely affected other systems used to mitigate a LOCA resulting in a total loss of their function (e.g., Interfacing System LOCA)?" In this case, because of the available margins in the flange material strength, the inspector answered these questions 'No,' and this issue screened as having very low safety significance (Green).

This finding had a cross-cutting aspect in the Resources component of the Human Performance cross-cutting area because the licensee did not have complete, accurate, and up-to-date design documentation, procedures, and work packages. Specifically, the licensee failed to ensure the applicable ASME Code Section III design limit for bearing stress (design basis) was correctly translated into design document EC 379850. Without NRC intervention, the licensee's engineering staff would not have recognized the need to evaluate the flange bearing stress and therefore this finding reflected current performance (H.2(c)).

Enforcement: Title 10 CFR 50, Appendix B, Criterion III, "Design Control," states, in part that measures shall be established to assure that applicable regulatory requirements and the design basis, as defined in 10 CFR 50.2 and as specified in the license application, for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures, and instructions.

Contrary to the above, from May 7, 2010 through October 31, 2013, the licensee failed to correctly maintain the design basis for the Unit 2 reactor vessel flange within the limits established by ASME Section III. Specifically, the licensee failed to ensure the applicable ASME Code Section III design limit for maximum bearing stress (design basis) was correctly translated into design document EC 379850, "Operation of Reactor Vessel with One Out-of-Service Closure Stud," which approved a change in the design for the Unit 2 reactor vessel. Because this violation was of very low safety significance and was entered into the licensee's CAP as IR 01578717, "Unit 2 RV Closure Stud Bearing Stress is Above ASME Allowed," this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy **(NCV 05000455/2013005-07, Inadequate Reactor Vessel Stress Analysis for Unit 2 Missing Head Stud**).

## 1R19 Post-Maintenance Testing (71111.19)

### .1 Post-Maintenance Testing

#### a. Inspection Scope

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

- Unit 2 Train 'B' Diesel Oil Storage Tank Room Door Following Repairs;
- Unit 1 Train 'B' Auxiliary Feedwater Valve 1AF13G Following Breaker Replacement;
- Unit 1 Train 'B' Auxiliary Feedwater Valve 1AF17B Following Breaker Replacement;
- Unit 1 Train 'B' Diesel Generator Following Governor Replacement;
- Unit 0 Train 'A' Essential Service Water Make-Up Pump Following Maintenance; and
- Unit 2 Train 'A' Reactor Vessel Level Indication System/Core Exit Thermo-Couple Following Maintenance.

These activities were selected based upon the structure, system, or component's ability to impact risk. The inspectors evaluated these activities for the following (as applicable): 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 TSs, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications 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, entering them into the CAP at the appropriate threshold, and correcting the problems commensurate with their importance to safety. Documents reviewed are listed in the Attachment.

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 4.13.1-1, Unit 1 Reactor Coolant System Inventory Balance (RCS);
- 1BOSR 0.5-3.AF.1-1, ASME Surveillance Requirements for the ‘A’ Train of AF SX Supply Valves (IST); and
- Unit 2 Source and Intermediate Range Instrument Calibrations (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 inservice testing 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 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 function following testing;
- were all problems identified during the testing appropriately documented and dispositioned in the licensee's CAP;
- where applicable, were annunciators and other alarms demonstrated to be functional and were annunciator and alarm setpoints consistent with design documents; and
- where applicable, were alarm response procedure entry points and actions consistent with the plant design and licensing documents.

Documents reviewed are listed in the Attachment.

This inspection constituted one routine surveillance testing sample, one inservice testing sample, and one reactor coolant system leak detection inspection sample as defined in IP 71111.22, Sections -02 and -05.

b. Findings

No findings were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (IP 71114.04)

a. Inspection Scope

The Office of Nuclear Security and Incident Response (NSIR) headquarters' staff performed an in-office review of the latest revisions to the Emergency Plan and various Emergency Plan Implementing Procedures (EPIPs) located under ADAMS Accession Numbers ML123260651, ML130180297, ML13162A199, and ML13200A124 as listed in the Attachment.

The licensee transmitted EPIP revisions to the NRC pursuant to the requirements of 10 CFR Part 50, Appendix E, Section V, "Implementing Procedures." The NRC's review was not documented in a safety evaluation report and did not constitute approval of licensee-generated changes; therefore, these revisions are subject to future inspection. Documents reviewed are listed in the Attachment.

This inspection constituted one sample as defined in IP 71114.04-05

b. Findings

No findings were identified.

## 2. RADIATION SAFETY

**Cornerstones: Occupational Radiation Safety and Public Radiation Safety**

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

Inspection activities documented in NRC Inspection Report 05000454/2013004; 05000455/2013004 for IP 71124.01 were documented as a partial sample as defined in IP 71124.01-05. The inspectors completed all required inspection activities and the information reported in the referenced report constituted one complete sample as defined in IP 71124.01-05.

2RS5 Radiation Monitoring Instrumentation (71124.05)

This inspection constituted one complete sample as defined in IP 71124.05-05.

.1 Inspection Planning (02.01)

a. Inspection Scope

The inspectors reviewed the plant Final Safety Analysis Report (FSAR) to identify radiation instruments associated with monitoring area radiological conditions, including airborne radioactivity, process streams, effluents, materials/articles, and workers. Additionally, the inspectors reviewed the instrumentation and the associated TS requirements for post-accident monitoring instrumentation, including instruments used for remote emergency assessment.

The inspectors reviewed a listing of in-service survey instrumentation, including air samplers and small article monitors, along with instruments used to detect and analyze workers' external contamination. Additionally, the inspectors reviewed personnel contamination monitors and portal monitors, including whole-body counters, to detect workers' internal contamination. The inspectors reviewed this list to assess whether an adequate number and type of instruments were available to support operations.

The inspectors reviewed licensee and third-party evaluation reports of the Radiation Monitoring Program since the last inspection. These reports were reviewed for insights into the licensee's program and to aid in selecting areas for review ("smart sampling").

The inspectors reviewed procedures that governed instrument source checks and calibrations, focusing on instruments used for monitoring transient high radiological conditions, including instruments used for underwater surveys. The inspectors reviewed the calibration and source check procedures for adequacy and as an aid to smart sampling.

The inspectors reviewed the area radiation monitor alarm setpoint values and setpoint bases as provided in the TSs and the FSAR.

The inspectors reviewed effluent monitor alarm setpoint bases and the calculation methods provided in the Offsite Dose Calculation Manual (ODCM).

b. Findings

No findings were identified.

.2 Walkdowns and Observations (02.02)

a. Inspection Scope

The inspectors walked down effluent radiation monitoring systems, including at least one liquid and one airborne system. Focus was placed on flow measurement devices and all accessible point-of-discharge liquid and gaseous effluent monitors of the selected systems. The inspectors assessed whether the effluent/process monitor configurations aligned with ODCM descriptions and observed monitors for degradation and out-of-service tags.

The inspectors selected portable survey instruments that were in use or available for issuance and assessed calibration and source check stickers for currency, as well as instrument material condition and operability.

The inspectors observed licensee staff performance as the staff demonstrated source checks for various types of portable survey instruments. The inspectors assessed whether high range instruments were source checked on all appropriate scales.

The inspectors walked down area radiation monitors and continuous air monitors to determine whether they were appropriately positioned relative to the radiation sources or areas they were intended to monitor. Selectively, the inspectors compared monitor response (via local or remote control room indications) with actual area conditions for consistency.

The inspectors selected personnel contamination monitors, portal monitors, and small article monitors and evaluated whether the periodic source checks were performed in accordance with the manufacturer's recommendations and licensee procedures.

b. Findings

No findings were identified.

.3 Calibration and Testing Program (02.03)

Process and Effluent Monitors

a. Inspection Scope

The inspectors selected effluent monitor instruments (such as gaseous and liquid) and evaluated whether channel calibration and functional tests were performed consistent with radiological effluent TSs/ODCM. The inspectors assessed whether: (a) the licensee calibrated its monitors with National Institute of Standards and Technology traceable sources; (b) the primary calibrations adequately represented the plant nuclide mix; (c) when secondary calibration sources were used, the sources were verified by the primary calibration; and (d) the licensee's channel calibrations encompassed the instrument's alarm setpoints.

The inspectors assessed whether the effluent monitor alarm setpoints were established as provided in the ODCM and station procedures.

For changes to effluent monitor setpoints, the inspectors evaluated the basis for the changes to ensure that an adequate justification existed.

b. Findings

No findings were identified.

Laboratory Instrumentation

a. Inspection Scope

The inspectors assessed laboratory analytical instruments used for radiological analyses to determine whether daily performance checks and calibration data indicated that the frequency of the calibrations was adequate and there were no indications of degraded instrument performance.

The inspectors assessed whether appropriate corrective actions were implemented in response to indications of degraded instrument performance.

b. Findings

No findings were identified.

Whole Body Counter

a. Inspection Scope

The inspectors reviewed the methods and sources used to perform whole body count functional checks before daily use of the instrument and assessed whether check sources were appropriate and aligned with the plant's isotopic mix.

The inspectors reviewed whole body count calibration records since the last inspection and evaluated whether calibration sources were representative of the plant source term and that appropriate calibration phantoms were used. The inspectors looked for anomalous results or other indications of instrument performance problems.

b. Findings

No findings were identified.

Post-Accident Monitoring Instrumentation

a. Inspection Scope

The inspectors selected containment high range monitors and reviewed the calibration documentation since the last inspection.

The inspectors assessed whether an electronic calibration was completed for all range decades above 10 rem/hour and whether at least 1 decade at or below 10 rem/hour were calibrated using an appropriate radiation source.

The inspectors assessed whether calibration acceptance criteria were reasonable, accounting for the large measuring range and the intended purpose of the instruments.

The inspectors selected effluent/process monitors that were relied on by the licensee in its emergency operating procedures as a basis for triggering emergency action levels and subsequent emergency classifications, or to make protective action recommendations during an accident. The inspectors evaluated the calibration and availability of these instruments.

The inspectors reviewed the licensee's capability to collect high range, post-accident iodine effluent samples.

As available, the inspectors observed electronic and radiation calibration of these instruments to assess conformity with the licensee's calibration and test protocols.

b. Findings

No findings were identified.

Portal Monitors, Personnel Contamination Monitors, and Small Article Monitors

a. Inspection Scope

For each type of these instruments used on site, the inspectors assessed whether the alarm setpoint values were reasonable under the circumstances to ensure that licensed material was not released from the site.

The inspectors reviewed the calibration documentation for each instrument selected and discussed the calibration methods with the licensee to determine consistency with the manufacturer's recommendations.

b. Findings

No findings were identified.

Portable Survey Instruments, Area Radiation Monitors, Electronic Dosimetry, and Air Samplers/Continuous Air Monitors

a. Inspection Scope

The inspectors reviewed calibration documentation for at least one of each type of instrument. For portable survey instruments and area radiation monitors, the inspectors reviewed detector measurement geometry and calibration methods and had the licensee demonstrate use of its instrument calibrator, as applicable. The inspectors conducted comparison of instrument readings versus an NRC survey instrument if problems were suspected.

As available, the inspectors selected portable survey instruments that did not meet acceptance criteria during calibration or source checks to assess whether the licensee had taken appropriate corrective actions for instruments found significantly out of calibration (e.g., greater than 50 percent). The inspectors evaluated whether the licensee evaluated the possible consequences of instrument use since the last successful calibration or source check.

b. Findings

No findings were identified.

Instrument Calibrator

a. Inspection Scope

As applicable, the inspectors reviewed the current output values for the licensee's portable survey and area radiation monitor instrument calibrator units. The inspectors assessed whether the licensee periodically measured calibrator output over the range of the instruments used through measurements by ion chamber/electrometer.

The inspectors assessed whether the measuring devices had been calibrated by a facility using National Institute of Standards and Technology traceable sources and whether corrective factors for these measuring devices were properly applied by the licensee in its output verification.

b. Findings

No findings were identified.

Calibration and Check Sources

a. Inspection Scope

The inspectors reviewed the licensee's 10 CFR Part 61, "Licensing Requirements for Land Disposal of Radioactive Waste," source term to assess whether calibration sources used were representative of the types and energies of radiation encountered in the plant.

b. Findings

No findings were identified.

.4 Problem Identification and Resolution (02.04)

a. Inspection Scope

The inspectors evaluated whether problems associated with radiation monitoring instrumentation were being identified by the licensee at an appropriate threshold and were properly addressed for resolution in the licensee's CAP. The inspectors assessed the appropriateness of the corrective actions for a selected sample of problems documented by the licensee that involved radiation monitoring instrumentation.

b. Findings

No findings were identified.

## 4. OTHER ACTIVITIES

**Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness**

4OA1 Performance Indicator Verification (71151)

.1 Safety System Functional Failures

a. Inspection Scope

The inspectors sampled licensee submittals for the Safety System Functional Failures performance indicator (PI) for Units 1 and 2 for the period from the third quarter 2012 through the third quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, and NUREG-1022, "Event Reporting Guidelines 10 CFR 50.72 and 50.73," were used. The inspectors reviewed the licensee's operator narrative logs, operability assessments, maintenance rule records, maintenance work orders, IRs, event reports and NRC integrated inspection reports for the period October 2012 through September 2013 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two safety system functional failures samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.2 Mitigating Systems Performance Index - Emergency AC Power System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index (MSPI) - Emergency AC Power System PI for Units 1 and 2 for the period from the third quarter 2012 through the third quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, MSPI derivation reports, IRs, event reports, and NRC integrated inspection reports for the period of October 2012 through September 2013 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI emergency AC power system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.3 Mitigating Systems Performance Index - High Pressure Injection Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - High Pressure Injection Systems PI for Units 1 and 2 for the period from the third quarter 2012 through the third quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, MSPI derivation reports, event reports and NRC integrated inspection reports for the period of October 2012 through September 2013 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI high pressure injection system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.4 Mitigating Systems Performance Index - Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - Heat Removal System PI for Units 1 and 2 for the period from the third quarter 2012 through the third quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, event reports, MSPI derivation reports, and NRC integrated inspection reports for the period October 2012 through September 2013 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI heat removal system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.5 Mitigating Systems Performance Index - Residual Heat Removal System

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - Residual Heat Removal System PI for Units 1 and 2 for the period from the third quarter 2012 through the third quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, MSPI derivation reports, event reports and NRC integrated inspection reports for the period of October 2012 through September 2013 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI residual heat removal system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

.6 Mitigating Systems Performance Index - Cooling Water Systems

a. Inspection Scope

The inspectors sampled licensee submittals for the Mitigating Systems Performance Index - Cooling Water Systems PI for Units 1 and 2 for the period from the third quarter 2012 through the third quarter 2013. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6, dated October 2009, were used. The inspectors reviewed the licensee's operator narrative logs, IRs, MSPI derivation reports, event reports and NRC integrated inspection reports for the period October 2012 through September 2013 to validate the accuracy of the submittals. The inspectors reviewed the MSPI component risk coefficient to determine if it had changed by more than 25 percent in value since the previous inspection, and if so, whether the change was in accordance with applicable NEI guidance. The inspectors also reviewed the licensee's IR database to determine if any problems had been identified with the PI data collected or transmitted for this indicator. Documents reviewed are listed in the Attachment.

This inspection constituted two MSPI cooling water system samples as defined in IP 71151-05.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152)

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

.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 whether identification of the problem was complete and accurate; whether timeliness was commensurate with the safety significance of the issue; whether the evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent-of-condition reviews, and previous occurrences reviews were proper and adequate; and whether the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the Attachment.

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 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results. The inspectors' review nominally considered the 6-month period of June 1, 2013 through December 1, 2013, although some examples expanded beyond those dates where the scope of the trend warranted.

The review also included issues that were documented outside the normal CAP in major equipment problem lists, repetitive and/or rework maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self-assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's CAP trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

This review constituted one semi-annual trend inspection sample as defined in IP 71152-05.

b. Findings

No findings were identified.

.4 Annual Sample: Review of Operator Workarounds

a. Inspection Scope

The inspectors evaluated the licensee's implementation of their process used to identify, document, track, and resolve operational challenges. Inspection activities included, but were not limited to, a review of the cumulative effects of the operator workarounds on system availability and the potential for improper operation of the system, for potential impacts on multiple systems, and on the ability of operators to respond to plant transients or accidents.

The inspectors performed a review of the cumulative effects of operator workarounds. The documents listed in the Attachment were reviewed to accomplish the objectives of the inspection procedure. The inspectors reviewed both current and historical operational challenge records to determine whether the licensee was identifying operator challenges at an appropriate threshold, had entered them into their CAP and proposed or implemented appropriate and timely corrective actions which addressed each issue. Reviews were conducted to determine if any operator challenge could increase the possibility of an Initiating Event, if the challenge was contrary to training, required a change from long-standing operational practices, or created the potential for inappropriate compensatory actions. Additionally, all temporary modifications were reviewed to identify any potential effect on the functionality of Mitigating Systems, impaired access to equipment, or required equipment uses for which the equipment was not designed. Daily plant and equipment status logs, degraded instrument logs, and operator aids or tools being used to compensate for material deficiencies were also assessed to identify any potential sources of unidentified operator workarounds.

This review constituted one operator workaround annual inspection sample as defined in IP 71152-05.

b. Findings

No findings were identified.

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

.1 (Closed) Licensee Event Report (LER) 05000455/2013-003-00: Unit 2 Train A Diesel Generator (DG) Ventilation Fan Not Reset

On August 15, 2011, with Unit 2 in Mode 1 at 100 percent reactor power, a post-maintenance test for a modification of the 2A DG ventilation fan control circuit left the fan in a condition that rendered it incapable of starting automatically and therefore inoperable. The condition was discovered 2 days later during a routine DG surveillance. The condition was immediately corrected when discovered, allowing the surveillance to be completed. Other corrective actions included clearly communicating requirements to station personnel to ensure the as-left condition of components/systems being tested was in accordance with the design requirements. An additional review was performed for all pending critical modifications to ensure that post-maintenance test instructions provided sufficient guidance to test and properly restore equipment lineups.

Since the automatic start of the ventilation fan with no operator action is a required support function for the DG, the 2A DG had been inoperable for 2 days, and the station had not performed the required TS surveillances for one DG inoperable. The operability of the DG was incorrectly assessed at the time of the original discovery and as a result, the reportability of the failure to meet TS requirements was not correctly assessed. The incorrect assessment of operability and reportability was previously discussed in NRC Problem Identification and Resolution Inspection Report 05000454/2013007; 05000455/2013007. This LER was submitted to satisfy the reporting requirements for the original event. Documents reviewed are listed in the Attachment. This LER is closed.

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

4OA5 Other Activities

.1 Institute of Nuclear Power Operations (INPO) Plant Assessment Report Review

a. Inspection Scope

The inspectors reviewed the final report for the INPO plant assessment conducted in December 2012. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC perspectives of licensee performance and to verify if any significant safety issues were identified that required further NRC follow-up.

b. Findings

No new issues or findings were identified.

.2 Licensee Strike Contingency Plans (92709)

a. Inspection Scope

Due to the fact that the International Brotherhood of Electrical Workers (IBEW) Local 15 contract affecting the site was scheduled to expire on December 31, 2013, and that in the absence of an agreement, an inspection was needed to ensure the continued safe operation of the facility, the inspectors reviewed the licensee's work stoppage plans to determine if the plans adequately addressed the areas of reactor operations, emergency planning, facility security, fire protection, TSs, and other regulatory requirements in the event of an employee strike or management lockout. The inspectors reviewed records and conducted interviews with licensee staff to verify that qualified personnel would be available to meet the minimum requirements for safe operation of the plant, if a strike or lockout were to occur. No actual work stoppage occurred during the inspection period.

b. Findings

No findings were identified.

.3 (Closed) Verification of Margin-to-Overfill Backfit Corrective Actions and Extent of Condition Review; EA [Enforcement Action] 11-051; VIO 05000454/2011013-01; 05000455/2011013-01, Restoring Compliance with Respect to Single Failures

On May 10, 2012, the NRC issued Inspection Report 05000454/2012002; 05000455/2012002, documenting follow-up actions taken to address a Byron Station steam generator tube rupture (SGTR) margin-to-overfill (MTO) issue that was first identified during an NRC Component Design Bases Inspection (CDBI) conducted in 2009. In NRC Inspection Report 05000454/2012002; 05000455/2012002, the inspectors concluded that the licensee's extent-of-condition review for the SGTR MTO issue appeared to be adequate and the issue would remain open pending verification that proposed power-operated relief valve (PORV) power supply modifications were completed.

During the week of October 21, 2013, the inspectors reviewed licensee modifications pertaining to the addition of an independent PORV power supply. The inspectors reviewed the modification packages for both units and performed a walkdown of the installed modifications. The inspectors did not identify any discrepancies between the design and the as-built condition. However, during their inspection activities, the inspectors identified that the licensee had not documented the completion of all required post-modification testing in the modification packages associated with the modification and therefore, it appeared that some post-modification testing had not been completed. In response to this issue, the licensee initiated IR 01576128, "Evidence of All 1C MS [Main Steam] PORV Battery Backup Mod [Modification] Tests Not Found." The licensee subsequently reviewed completed WOs and determined that all required testing had, in fact, been completed and therefore the documentation issue was administrative in nature. Documents reviewed are listed in the Attachment.

The failure to properly document the completion of post-modification testing associated with modification activities that installed independent PORV power supplies was contrary to the requirements of 10 CFR 50, Appendix B, Criterion III, Design Control. However, because the issue was administrative in nature and the testing had, in fact, been performed, the issue was determined to not be more than minor since there was no actual impact on any of the Reactor Safety cornerstones. Thus, the failure to comply with regulatory requirements constitutes a minor violation that is not subject to enforcement action in accordance with the NRC's Enforcement Policy.

Based on the above review, the inspectors concluded the licensee's PORV power supply modifications were complete and this issue is closed.

.4 <u>(Closed) Unresolved Item (05000454/2012005-04; 05000455/2012005-04): Concerns with the Bases for the Acceptability of GOTHIC for Void Transport Prediction</u>

The NRC documented an Unresolved Item (URI) in NRC Inspection Report 05000454/2012005; 05000455/2012005 involving the use of computer software GOTHIC to justify the acceptability of a design basis change which incorporated gas voids in the suction piping from the containment emergency sump into the design of the plant. Specifically, the licensee identified unventable sections at the suction piping downstream of the SI8811 and CS009A valves. As a result, the licensee evaluated the acceptability of incorporating a maximum potential void size value into their licensing and design bases and justified this maximum value using GOTHIC. However, the inspectors noted instances where the basis of GOTHIC as a void assessment analysis tool was questionable. Specifically, the inspectors noted several differences between test and actual plant configurations and conditions which were discussed in NRC Inspection Report 05000454/2011002; 05000455/2011002. This issue was unresolved pending further review by the Office of Nuclear Reactor Regulation (NRR) on the use of GOTHIC to justify the acceptability of this design bases change.

During this inspection period, NRR personnel reviewed design basis documents and engineering evaluations associated with the licensee's application of GOTHIC. The result of this review was documented in "Completion of Reactor Systems Branch Assessment of Open Issues Related to Byron Station, Units 1 and 2, NRC Integrated Inspection Report 05000454/2011-002; 05000455/2011-002 (ML12289A022)." The report concluded that, although the GOTHIC verification was weak due to the limited comparisons to experimental data, there were no regulatory issues with the use of

GOTHIC for analysis of the void in the piping from the containment sump. The main factors supporting this conclusion included:

- Pump inlet void fractions and volumes predicted by GOTHIC were increased to account for potential prediction error in design basis applications (i.e., an acceptable safety factor was applied);

- Generally accepted modeling methodologies were used in the GOTHIC predictions;

- Conservative and bounding system geometry was used in the GOTHIC modeling; and

- GOTHIC predicted results were consistent with simplified methodologies.

The conclusions stated in the NRR report were only applicable to the identified void susceptible locations under the reviewed physical and operational configurations and conditions.

Based on the above, the inspectors determined that no performance deficiencies or violations of regulatory requirements were associated with this URI. Documents reviewed are listed in the Attachment. This review did not represent an inspection sample. This URI is closed.

.5 <u>Temporary Instruction (TI) 2515/182 - Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks</u>

a. <u>Inspection Scope</u>

Leakage from buried and underground pipes has resulted in ground water contamination incidents with associated heightened NRC and public interest. The industry issued guidance document NEI 09-14, "Guideline for the Management of Buried Piping Integrity," (ADAMS Accession No. ML1030901420) to describe the goals and required actions (commitments made by the licensee) resulting from this underground piping and tank initiative. On December 31, 2010, NEI issued Revision 1 to NEI 09-14, "Guidance for the Management of Underground Piping and Tank Integrity," (ADAMS Accession No. ML110700122), with an expanded scope of components, which included underground piping that was not in direct contact with the soil and underground tanks. On November 17, 2011, the NRC issued TI 2515/182, "Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks," to gather information related to the industry's implementation of this initiative. In April 2013, the industry issued Revision 3 to NEI 09-14 to address changes in program scope and milestone dates (ADAMS Accession No. ML13130A322).

On December 19, 2013, the inspectors conducted a review of records and procedures related to the licensee's program for buried pipe, underground pipe, and tanks in accordance with Phase II of TI 2515/182. This review was performed to confirm that the licensee's program contained attributes consistent with Sections 3.3 A and 3.3 B of NEI 09-14 and to confirm that these attributes were scheduled and/or completed by the NEI 09-14 Revision 3 deadlines. The inspectors interviewed licensee staff responsible for the Buried Pipe Program and reviewed documentation to determine whether the program was managed effectively.

Based upon the scope of the review described above, Phase II of TI 2515/182 was completed.

b. Observations

The licensee's buried piping and underground piping and tanks program was inspected in accordance with Paragraph 03.02.a of TI 2515-182 and it was confirmed that activities that correspond to completion dates specified in the program which have passed since the Phase I inspection was conducted, have been completed. Additionally, the licensee's Buried Piping and Underground Piping and Tanks Program was inspected in accordance with Paragraph 03.02.b of TI 2515-182 and responses to specific questions found in http://www.nrc.gov/reactors/operating/ops-experience/buried-pipe-ti-phase-2-insp-req-2011-11-16.pdf, were submitted to NRC headquarters staff.

c. Findings

No findings were identified.

4OA6 Management Meetings

.1 Exit Meeting Summary

On January 7, 2014, the inspectors presented the inspection results to Mr. B. Youman, 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.

.2 Interim Exit Meetings

Interim exits were conducted for:

- Results of the modification inspection for EC 379850 with Mr. R. Kearney on October 31, 2013;
- Results of the triennial heat sink inspection with Mr. B. Youman and other members of the licensee's staff on Friday November 8, 2013;
- Results of the radiation monitoring instrumentation inspection with Mr. B. Youman on November 22, 2013;
- The resolution of URI 05000454/2012005-04; 05000455/2012005-04 with Mr. E. Hernandez and other members of the licensee's staff via telephone on November 26, 2013;
- The inspection of the licensed operator requalification training annual operating test results with Mr. T. Sanders via telephone on December 9, 2013;
- An additional violation identified during the triennial heat sink inspection with Mr. E. Hernandez and other members of the licensee's staff on December 12, 2013 via telephone; and
- Review of the Industry Initiative to Control Degradation of Underground Piping and Tanks, TI 2515/182, Phase II, with Mr. B. Youman and other members of the licensee's staff on December 19, 2013.

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

<u>Licensee</u>

B. Youman, Plant Manager
T. Chalmers, Operations Director
E. Hernandez, Engineering Director
J. Fiesel, Maintenance Director
A. Christianson, Acting Work Management Director
S. Gackstetter, Regulatory Assurance Manager
G. Armstrong, Security Manager
B. Barton, Radiation Protection Manager
K. Gerard, Radiation Protection Instrument Coordinator
J. Reed, Health Physicist
P. Bierdeman, Buried Pipe Program Owner
L. Zurawski, NRC Coordinator

<u>Nuclear Regulatory Commission</u>

E. Duncan, Chief, Reactor Projects Branch 3

<u>Illinois Emergency Management Agency (IEMA)</u>

C. Settles, IEMA

## LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

| | | |
|---|---|---|
| 05000454/2013005-01; 05000455/2013005-01 | NCV | Essential Service Water Blowdown Isolation Valves Not Tested (Section 1R07.1.b(1)) |
| 05000454/2013005-02; 05000455/2013005-02 | NCV | Intake Structure Silt Level Acceptance Criteria Were Non-Conservative (Section 1R07.1.b(2)) |
| 05000454/2013005-03; 05000455/2013005-03 | NCV | Failure to Implement Preventive Maintenance Procedure Replacement Schedules for Essential Service Water Makeup Pump Diesel Engine Hoses (Section 1R07.1.b(3)) |
| 05000455/2013005-04 | NCV | Analytical Basis for PTL Curves Not Maintained Consistent With the Unit 2 Vessel Head Stud Configuration (1R18.1.b(1)) |
| 05000455/2013005-05 | NCV | Reactor Vessel Design Documents Not Updated to Reflect Unit 2 Missing Head Stud (1R18.1.b(2)) |
| 05000455/2013005-06 | NCV | Corrosion Effects on the Unit 2 Reactor Vessel Not Monitored (1R18.1.b(3)) |
| 05000455/2013005-07 | NCV | Inadequate Reactor Vessel Stress Analysis for Unit 2 Missing Head Stud (1R18.1.b(4)) |

Closed

| | | |
|---|---|---|
| 05000454/2011013-01; 05000455/2011013-01 | VIO | Restoring Compliance with Respect to Single Failures (Section 4OA5.3) |
| 05000454/2013005-01; 05000455/2013005-01 | NCV | Essential Service Water Blowdown Isolation Valves Not Tested (Section 1R07.1.b(1)) |
| 05000454/2013005-02; 05000455/2013005-02 | NCV | Intake Structure Silt Level Acceptance Criteria Were Non-Conservative (Section 1R07.1.b(2)) |
| 05000454/2013005-03; 05000455/2013005-03 | NCV | Failure to Implement Preventive Maintenance Procedure Replacement Schedules for Essential Service Water Makeup Pump Diesel Engine Hoses (Section 1R07.1.b(3)) |
| 05000455/2013005-04 | NCV | Analytical Basis for PTL Curves Not Maintained Consistent With the Unit 2 Vessel Head Stud Configuration (1R18.1.b(1)) |
| 05000455/2013005-05 | NCV | Reactor Vessel Design Documents Not Updated to Reflect Unit 2 Missing Head Stud (1R18.1.b(2)) |
| 05000455/2013005-06 | NCV | Corrosion Effects on the Unit 2 Reactor Vessel Not Monitored (1R18.1.b(3)) |
| 05000455/2013005-07 | NCV | Inadequate Reactor Vessel Stress Analysis for Unit 2 Missing Head Stud (1R18.1.b(4)) |
| 05000454/2012005-04; 05000455/2012005-04 | URI | Concerns with the Bases for the Acceptability of GOTHIC for Void Transport Prediction (Section 4OA5.4) |
| 05000455/2013-003-00 | LER | Unit 2A Train Diesel Generator Ventilation Fan Not Reset (Section 4OA3.1) |

Discussed

None.

## 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.

<u>Section 1R04</u>

- M-37: Diagram of Auxiliary Feedwater, Sheet 1; Revision BC
- M-136: Diagram of Safety Injection, Sheet 1; Revision BA
- M-136: Diagram of Safety Injection, Sheet 3; Revision AD
- M-46: Diagram of Containment Spray, Sheet 1A; Revision AN

<u>Section 1R05</u>

- Drawing A-307: A-450, Lintel Schedule, Sheet No. 1; Revision AC
- IR 1572406: NRC Identified Issues During Plant Walkdown; October 15, 2013
- Drawing A-232: Auxiliary Bldg. Upper Basement Floor Plan El. 383'-0" Area 6, Byron Station, Units 1 & 2 Commonwealth Edison Co. Chicago, Illinois; Revision AT
- IR 1572406: NRC Identified Issues During Plant Walkdown; October 15, 2013

<u>Section 1R07</u>

- IR 1582656: NRC ID - Vendor Manual Recommendation Not Being Implemented; November 8, 2013
- 0BOSR 0.1-0: U0 All MODEs/All Times Shiftly and Daily Operating Surveillance; Revision 43
- 0BOSR 5.5.8.SX.5-1c: U0 Comprehensive IST Requirements for ESW Makeup Pump 0A; Revision 6
- 1BEP-0: Reactor Trip or SI U1; Revision 204
- 1BOSR 0.5-2.SX.3-1: U1 Train 'A' Essential Service Water Valve Indication Test; Revision 4
- IR 255966: U0 CC HX GL 89-13 Inspection Past Critical Date; September 23, 2004
- IR01578515: Inlet/Outlet Cover Plate Needs Replacement in Next WO Window; October 22, 2013
- ATD-0063: Heat Load to the UHS During a LOCA; Revision 6
- BB-MISC-006: Risk Assessment – Evaluation of Risk Impact from IR 1088765; Revision 0
- BOP AF-7T1: Diesel Driven AF Pump Operating Log; Revision 21
- BOP CC-14: Post LOCA Alignment of the CC System; Revision 10
- BOP SX-11: ESW Mechanical Draft Cooling Tower Fan Start-Up; Revision 9
- BYR 96-277: Determination of Maximum Allowable Silt Depth in River Screen House; December 10, 1996
- BYR07-058: Component Cooling Water Pump NPSH Adequacy; Revision 0
- BYR97-034: ESW Cooling Tower Basin Minimum Volume Versus Level and Minimum Usable Volume Calculation; Revision OA
- BYR97-127: Byron UHS Cooling Tower Performance Calculation; Revision 1
- BYR97-467 : Component Cooling Water Heat Exchanger Tube Plugging Evaluation; Revision 4
- BYR98-185: ESW Makeup Pump Diesel Oil Storage Tank Minimum Level; Revision 0A
- BYRON 2004-0035: Regulatory Commitment Change Summary Report; April 1 2004
- Detroit Diesel Vendor Manual; October 1989

- EC351458: Provide Justification for Extending GL 89-13 Inspection of 0CC01A Heat Exchanger Past Its Critical Due Date of 9/22/04; March 23, 2005
- M-66A: Composite Diagram of Component Cooling System; Revision C
- NED-M-MSD-009: Byron UHS Cooling Tower Basin Temperature Calculation; Revision 8
- NED-M-MSD-014: Byron UHS Cooling Tower Basin Makeup Calculation; Revision 9
- WO 990157073: Essential Service Water Flow Verification; April 23, 2001
- WO 00394057: 0CC01A – HX Inspection Per Generic Letter 89-13/BVP 800 – 30; March 4, 2005
- WO 1235743: U2 (SX-3-1) VT XI (2A Pump Running); December 17, 2010
- WO 1302154: U1 (SX-3-8) VT XI (1A/1B Pump Running); September 28, 2010
- WO 1395853: Essential Service Water Makeup Pump Support 0BVSR Z.7.A 6-1; July 18, 2012
- WO 1401605: Essential Service Water Makeup Pump Support 0BOSR Z.7.A 6-2; August 22, 2012
- WO 1458160: U1 (SX-3-1) VT XI (1A Pump Running); March 11, 2013
- WO 1463222: (SX-3-2) VT XI (1B Pump Train Work); November 8, 2013
- WO 1465222: Digital Channel Operability Test of 0PR09J; March 21, 2012
- WO 1595644: 1CC01PB Comprehensive IST REQMTS for Component Cooling Water; February 28, 2013
- WO 1598302: 1CC01PA Comprehensive IST REQMTS for Component Cooling Water Pump; February 14, 2013
- WO 1608278: 0CC01P Comp IST RQMTS for Component Cooling Water Pump; March 27, 2012
- WO 803906: Support Eddy Current Testing Concurrent with GL 89-13; September 18, 2009
- WO 99013897: Essential Service Water Flow Verification; April 17, 1999
- WO 01440003-02: SXCT A Cell Inspection Per TRM; June 6, 2012
- WO 01443836-01: Inspection of RSH and ESW; July 5, 2012
- WO 01453217-01: Position Indication Test of the ESW 0SX162A-D and 0SX163A-H; December 28, 2012
- WO 01454068-01: Inspection in SXCT E Cell; November 31, 2012
- WO 01464962-01: ‘A’ Train ESW Valve Indication Test; February 8, 2013
- WO 01474864-01: Inspection in SXCT Basin; November 8, 2012
- WO 01475202-01: Position Indication Test of 1SX004, 010, 011, 033, 034 and 136; April 5, 2013
- WO 01491516-01: SX M/U Pump 0A Discharge Pressure Indication; May 8, 2013
- WO 01510587-01: HX Inspection 0B DSL DRV SX M/U PP JW; November 1, 2013
- WO 01609001-01: Inspection at RSH Intake Bay; March 8, 2013
- WO 01614186-01: De-Silting at 0A SX Basin (RSH); March 8, 2013
- WO 01645506-01: 0SX02PB Comprehensive IST Requirements for SX M/U Pump; August 23, 2013
- WO 01657021-01: Diver Inspection at RSH Intake Bay; August 12, 2013
- IR 1582385: Input Used in BYR 96-277 Is Not Conservative; November 7, 2013
- IR 1582114: Credited Operator Action Not in OP-BY-102-106; November 7, 2013
- IR 1579361: Valves 0SX161A/B Closure Not Functionally Tested; October 31, 2013
- IR 1581721: NRC Identified Dry Cracking on Air Hose to 2CC017; November 6, 2013
- IR 1582322: Flexible Conduit Partially Submerged in Water; November 7, 2013
- IR 1582656: NRC ID Vendor Manual Recommendation Not Being Implemented; November 8,2013
- IR 1582406: Past U-0 CC HX Inspection Exceeded 5 Yr Limit Without Justification; November 7, 2013

- IR 01590368: NRC ID - PCM Template/Vendor Manual Recommendation; November 26, 2013

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- LORT Annual Exam Status Report; Byron Generating Station 2013
- BY-56: Requalification Activities on Simulator; Revision 5

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- 0BVSR SX-2: Unit 0 Train B SX Makeup Pump Battery Bank B Capacity Test; Revision 3
- 0BHSR SX-7: Unit 0 Train B SX Makeup Pump Battery Bank B Capacity Test; Revision 0
- IEEE Std 1106: IEEE Recommended Practice for Installation, Maintenance, Testing, and Replacement of Vented Nickel-Cadmium Batteries for Stationary Applications; December 23, 2005
- IR 1564219: SX Batteries Fail Capacity Test; September 26, 2013
- IR 1566292: 0B SX Make-Up Pump Battery Failed Capacity Test; October 1, 2013
- IR 1567780: Enhancements to Ni-Cd Battery Capacity Testing Procedures; October 4, 2013
- IR 1571008: Low Electrolyte Levels on Previously Installed Battery Cells; October 11, 2013
- IR 1574928: NRC Question Regarding UFSAR for SX M/U PP Batteries; October 21, 2013
- IR 1576897: Enhancements to Ni-Cd Quarterly Surveillance Procedures; October 25, 2013
- NPR0024: Vendor Data for SAFT NIFE Nickel-Cadmium Batteries; August 1, 1994
- Maintenance Rule Evaluation, Boric Acid System; October 2013
- IR 1480881: Use of Boric Acid Transfer Pumps in Natural Circulation C/D; February 27, 2013
- IR 1482111: BAST Conditions; March 1, 2013
- IR 1513874: Boric Acid Storage Tank Bladder Issues Reported at Braidwood; May 14, 2013
- IR 1539576: Byron Review of Braidwood Potential USNRC Violation; July 25, 2013
- IR 1574889: U1 BAST Magnesium Over the Limit; October 21, 2013
- IR 1574891: U2 BAST Magnesium Over the Limit; October 21, 2013
- IR 1582873: Expected Condition U1/U2 BAST Magnesium; November 8, 2013
- IR 1588373: Sulfates Out of Spec High; November 21, 2013
- IR 1591346: U-1 Boric Acid Pump Filter Needs to be Changed; November 30, 2013
- IR 1591348: Replace U-2 Boric Acid Filter Following U-2 BAT Bladder Work; November 30, 2013
- IR 1591680: U-2 BAT OOS for Bladder Inspection and Possible Removal; December 1, 2013
- IR 1592270: 2AB03T Bladder Degradation/Emergent Removal; December 3, 2013
- IR 1594583: IEMA Questions Related to Boric Acid Tanks; December 9, 2013
- Calc RFS-M-988, 4% Boric Acid – Tank Volume; May 18, 1970

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- OP-AA-108-117: Protected Equipment Program; Revision 3
- IR 1577965: Emergent Clearance Orders Inside E-4; October 28, 2013
- IR 1577956: Emergent COS Inside E-4 with Significant Impact; October 23, 2013
- IR 1593462: High Vibrations on 0C VA Supply Fan 0VA01CC; December 5, 2012
- On-Line Risk Evaluations for the Week of December 2, 2013; Revision 1, 2, and 3
- CO 113963: Clearance Order for 0VA25Y A/B Damper & Actuator Inspection; Revision 0

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- Operability Evaluation 11-007:  Auxiliary Feedwater Pump Suction Concerns; Revision 4
- Operability Evaluation 13-004:  NonSafety-Related Gaskets Installed in Air Operated Valves; Revision 1
- IR 1590443:  2B DG Tripped in Cooldown Cycle
- Op Eval 13-07, Ultimate Heat Sink Capability with Loss of Essential Service Water Cooling Tower Fans; Revision 0
- Calc. BYR05-018, Tornado Missile Risk Assessment of Vulnerable Targets of Essential Service Water Cooling Towers; Revision 0

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- IR 01578276:  Byron PTLR Outside of NRC Approved Method; October 29, 2013
- IR 01578285:  Design Documentation is Not in Compliance with ASME; October 29, 2013
- IR 01578289:  EC 379850 Failed to Adequately Evaluate Boron Corrosion; October 29, 2013
- IR 01578717:  Unit 2 RV Closure Stud Bearing Stress is Above ASME Allowed; October 30, 2013
- IR 01061307:  Actions Associated with EC 379850; October 20, 2011
- IR 01061221:  U2 Vessel Head Closure Bolt 11 vs. Table 1.1-1; April 25, 2010
- IR 01059306:  U2 Reactor head Stud No. 11 Will Not Turn; April 21, 2010
- Calculation R-4016-00-1:  Reactor Vessel Bolting Evaluations Byron Station Units 1 and 2; Revision 1
- Calculation EDRE-EMT-110:  Engineering Report for the Evaluation of an Out of Service Closure-Stud in Byron Unit 2 Reactor Vessel; Revision 0
- Certified Design Analysis Contract 640-0012-51/52:  Closure Analysis; Revision 2
- Design Specification Sheet 676413:  Reactor Vessel; Revision 6
- Drawing 113E977:  4-Loop 173.00 ID Reactor Vessel, Sheet 1 & 2; Revision 5
- Drawing 2RPV-1-ISI:  Inspection Identification Drawing for ISI for RPV 2RC01R; Revision B
- EC 379850:  Operation of Reactor Vessel with One Out-of-Service Closure Stud; Revision 0
- Procedure BMP 3118-7:  Reactor Vessel Closure Head Installation; Revision 48
- VT-2 Visual Examination Record 2RC01R; May 16, 2010
- WCAP-16143:  Reactor Closure Head/Vessel Flange Requirements Evaluation for Byron/Braidwood Units 1 and 2, Revision 0
- Work Order 1332152-01:  Trim the No 11 Stud on the Reactor Closure Flange Per EC 379850; Revision 0
- EM-5892:  Main Loop Stop Valve Pressure Boundary Component Summary Report (LSIV)
- C-4044-00-01, Revision 001A:  Byron Loop Stop Isolation Valve (LSIV) Hydrostatic Test Report
- EC 382329:  Install HydraNuts on 1RC8002C Loop Stop Isolation Valve
- EC 382222:  Install HydraNuts on 1RC01PB Reactor Coolant Pump
- C-4044-00-02, Revision 001:  Owners Review of Byron Reactor Coolant Pump (RCP) HydraNut Stress Report
- EM-5111:  Pressure Boundary Component Summary Report for the Model 93A Reactor Coolant Pumps No. U383, U377, U376, and U390

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- IR 1577237:  1VD01CB Mod Testing Failed Mod Test Requirement; October 26, 2013
- IR 1577157:  Unexpected Response During 1B VD HELB Mod Testing; October 26, 2013
- IR 1570381:  Governor Actuator Not Labeled (1SC-DG250B); October 10, 2013
- WO 1686445: Unexpected Alarm Computer Trouble; November 14, 2013
- IR 1585092:  New CPU Board Not Configured Properly; November 13, 2013
- IR 1585066:  Spare Bought from Palo Verde is Bad; November 13, 2012
- IR 1585892:  'A' Train CETC Have All Failed – All Temps at a Locked In Value; November 15, 2013
- IR 1587880:  CPU Was Recently Replaced.  Potential Re-Work; November 20, 2013
- WO 1496778:  Replace Breaker for MCC 132X3-A5 (1AF017B); November 18, 2013
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- 1BOSR 8.1.2-2:  Unit 1 Train 'B' Diesel Generator Operability Surveillance; Revision 31
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- IR 1570572:  0A SX M/U Pump Had To Be Tripped During Monthly Run; October 10, 2013
- IR 1569456:  0A RSH Intake Failed Acceptance Criteria 0BMSR SX-5; October 8, 2013
- WO 1534981:  Replace Fuel Oil Supply Soft Seat Check Valve; October 10, 2013

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- IR 1569874:  Surveillance Calibrations Are Being Done Improperly; October 8, 2013
- BISR 3.1.1.11-200:  Surveillance Calibration of Nuclear Instrumentation Source and Intermediate Range System; Revision 20

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- EP-AA-1000:  Standardized Radiological Emergency Plan; Revision 22 and 23
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- EP-AA-110-200:  Dose Assessment; Revision 5
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- IR 01588368:  NRC Identified Enhancements to Instrument Program; November 21, 2013
- IR 01108103:  Enhancement Identified in NRC Inspection Lessons Learned; August 31, 2010
- IR 01092940:  Nuclear Safety Enhancement – Area Rad Monitors; July 21, 2010
- IR 01309099:  Procedure References Procedures that are Not Applicable; January 3, 2012
- IR 01091242:  Rem-Ball Source Check Failures Neutron Shepherd Suspect; July 15, 2010
- NOSA-BYR-12-04:  Chemistry, Radwaste; Effluent and Environmental Monitoring; June 7, 2012
- NOSA-BYR-13-06:  Radiation Protection Audit; July 9, 2013
- Functional Area Self-Assessment 1006770-03:  Radiation Instrumentation; June 11, 2010
- Functional Area Self-Assessment 14636872-02:  Radiation Instrumentation; September 26, 2013
- Work Order 01419221 01:  Perform Electronics Portion of 1AR-020; August 17, 2012

- Work Order 01419221 01: Perform Electronics Portion of 2AR-021; March 8, 2013
- RP-BY-901: 1/2RE-PR011 Low Gas and Particulate Containment Atmosphere Setpoint Change; Revision 7
- RP-BY-901, Attachment 1; 1RE-PR011 Particulate Setpoint Change Worksheet; Annual Setpoint Review; January 31, 2013
- RP-BY-901, Attachment 2; 1RE-PR011 Noble Gas Setpoint Change Worksheet; Annual Setpoint Review; January 31, 2013
- RP-BY-901, Attachment 2; 2RE-PR011 Noble Gas Setpoint Change Worksheet; Annual Setpoint Review; February 1, 2013
- RP-BY-901, Attachment 1: 2RE-PR011 Particulate Setpoint Change Worksheet; Annual Setpoint Review; January 31, 2013
- RP-BY-901, Attachment 1: 2RE-PR011 Particulate Setpoint Change Worksheet; Annual Setpoint Review; January 31, 2013
- RP-AP-900, 1/2RE-PR027 Stem Jet Air Ejector/Gland Steam Exhaust Setpoint Change; Revision 2
- RP-BY-903, 0RE-PR031/032/033/034 Gas Channel Setpoint Change; Revision 1
- RP-BY-904: Area Radiation Monitoring System Alert/High Alarm Setpoints; Revision 2
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- RP-BY-906: Response to Area and Process Radiation Monitor LCOARS or Out of Service Conditions; Revision 1
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- RP-BY-754: Calibration, Source Check, and Operation of the Ludlum Model 9-7 Ion Chamber; Revision 1
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- RP-AA-700-1501: Operation and Calibration of the Model SAM-9/11 Small Articles Monitor; Revision 1
- RP-BY-720: Calibration, Maintenance, and Operation of the IPM-8M Whole Body Frisking Monitor; Revision 4
- Calibration of the Canberra Fastscan B2 WBC System at the Byron Nuclear Generating Station; August 23, 2011
- Calibration of the Canberra Fastscan B2 WBC System at the Byron Nuclear Generating Station; August 23, 2012
- Calibration of the Canberra Fastscan B2 WBC System at the Byron Nuclear Generating Station; August 7, 2013
- Calibration of the Canberra Fastscan B1 WBC System at the Byron Nuclear Generating Station; August 6, 2013
- Byron 2013 Model 89 Gamma Shepherd Certification; January 31, 2013
- IR 1588778: NRC Identified Issue with IMD Test Report; November 22, 2013

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- IR 1585351: NRC ID: Operator Logs Need to be Enhanced for MSPI Data; November 13, 2013
- Comparison of Submitted Data and Information Contained in System Health Reports and Operations Logs between October 2012 and September 2013

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- IR 1575301: NRC & IEMA Question About 2A SI Room Removable Wall; October 21, 2013
- IR 1574928: NRC Question Regarding UFSAR for SX M/U PP Batteries; October 21, 2013
- IR 1576897: Enhancements to NI-CD Quarterly Surveillance Procedures; October 25, 2013
- IR 1574999: Unexpected Alarm—Aux Bldg Hot Water Coil Temp Low; October 21, 2013
- IR 1574934: Winter OPS U2 RWST and Filling 2D SI Accumulator; October 21, 2013
- IR 1578257: Operations Behind on Winter Readiness; October 29, 2013
- IR 1577022: New ETL Failed Shortly After Installation; October 26, 2013
- IR 1576565: Found Fire Dampers Dropped and ETLS Blown; October 25, 2013
- IR 1572406: NRC Identified Issues During Plant Walkdown; October 15, 2013
- IR 1572657: TCC Tags in Field Not Signed Off by Installer; October 16, 2013
- IR 1572593: High Contact Resistance Identified During HELB Testing; October 15, 2013
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- IR 1580439: ETLs Continue to Fail Prematurely; November 3, 2013
- IR 1580534: ETL Failure During Installation Process; November 3, 2013
- IR 1580381: Upper Right ETL Pulling Apart on 2VD17YB Damper; November 3, 2013
- IR 1568069: 281 F Fire Damper ETLs Failure at Braidwood; October 4, 2013
- IR 1567882: ETL On 1VD17YB is Degraded; October 4, 2013
- IR 1581043: One of the Electro Thermal Links on 1VX28Y is Separating; November 5, 2013
- IR 1580381: Upper Right ETL Pulling Apart on 2VD17YB Damper; November 3, 2013
- IR 1580534: ETL Failure During Installation Process; November 3, 2013
- OP-AA-102-103, Revision 3: Operator Workaround Program
- PMID 00141248: OP Work Arounds
- WO 01620530: OP-ST Shift to Review DEL, OOS Log, T-Mod Log, CC Log, EST Log
- IR 1585649: NRC URI 10 CFR 50.59 Evaluation Affecting Tornado Analysis; November 15, 2013
- IR 1585651: NRC URI Ultimate Heat Sink Limiting Design Basis Event; November 15, 2013
- IR 1585653: NRC URI Ultimate Heat Sink Design Changes; November 15, 2013

- IR 1585654: NRC URI Reduced Decay Time; November 15, 2013
- EnTech Report: Report Associated with “Circulating Cooling Water Pipeline Leaks and Resulting Erosion Voids”; Dated October 16, 2013
- IR 1567903: NRC Questions and Feedback on UHS Temperature Analysis; October 4, 2013
- IR 1567647: Lightning Strike Resulting in Momentary Loss of Line 0624; October 4, 2013
- IR 1567648: MET Tower Data Lost During Storm; October 4, 2013

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- LER 455-2013-003-00: Unit 2 A-Train Diesel Generator Ventilation Fan Not Reset
- IR 1567369: PI&R 2A DG Operability Concern
- IR 1252529: 2A DG Vent Fan Trip Signal Not Reset
- LER 455-2013-002-00; Unqualified Valve Diaphragm Installed in 2RE9160A
- WO 1675149: Replace Unqualified Valve Diaphragm Installed in 2RE9160A
- IR 1560608: Unqualified Valve Diaphragm Installed in 2RE9160A in B2R16

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- EC 380013: U1 Steam Generator Margin to Overfill (SG MTO) PORV Battery Backup Modification; Revision 7
- EC 380014: U2 Steam Generator Margin to Overfill (SG MTO) PORV Battery Backup Modification; Revision 7
- IR 01576128: Evidence of All 1C MS PORV Battery Backup Mod Tests Not Found; October 24, 2013
- WO 01410593: OPS perform (SG MTO) Operability Testing Per EC 380013; October 5, 2012
- WO 01410623: OPS perform (SG MTO) Operability Testing per EC 380014; July 6, 2012
- WO 01584504: Verify Acceptable Manual Stroke Ability 1C PORV; November 7, 2012
- EC 378161: Revise the Design Bases to Accept Potential Voided Piping Downstream of the 1/2CS009A Valves and the 1/2SI8811A/B Valves; October 22, 2010
- NAI-1459-001: “Comparison of GOTHIC Gas Transport Calculations With Test Data;” Revision 1
- ER-AA-5400: Buried Piping and Raw Water Corrosion Program (BPRWCP) Guide; Revision 5
- ER-AA-5400-1001: Raw Water Corrosion Program Guide; Revision 6
- ER-AA-5400-1002: Underground Piping and Tank Examination Guide; Revision 6
- ER-AA-5400-1003: Buried Pipe and Raw Water Corrosion Program (BPRWCP) Performance Indicators; Revision 5
- ER-AA-330: Conduct of Inservice Inspection Activities; Revision 9
- ER-AA-335-1008: Code Acceptance and Recording Criteria for Nondestructive (NDE) Surface Examination; Revision 3
- ER-AA-330-001: Section XI Pressure Testing; Revision 12
- ER-AA-335-015: VT-2 Visual Examination; Revision 13
- SA-AA-117: Excavation, Trenching, and Shoring; Revision 15
- ER-AA-335-010: Guidelines for ASME Code Allowable Flaw Evaluation and ASME Code Coverage Calculations; Revision 5
- Buried Pipe and Raw Water Systems Long Term Asset Management Strategy, December 2012
- Byron Underground Pipe and Tank Inspection Plan; December 17, 2012
- IR 01396003: Localized Pipe Wall Thinning Found on 0WW07AB-8 During NDE; August 1, 2012

- IR 01525244:  Perform Guided Wave Inspection of 2SX67AB-1.5 During B2R18; June 14, 2013
- IR 01581755:  Complete Test Point Installation for 0SX01AA-48; November 6, 2013
- IR 01354566:  Need WO to Repair Buried Cathodic Protection Conduit;
- April 16, 2012
- IR 01323228:  Excavate 1D008A-3 for Buried Pipe Inspection E12-11; February 6, 2012
- IR 01547288:  2012 Cathodic Protection Survey Results; August 15, 2013
- Report No. NUC2012124.00:  Condition Assessment Excavated Buried Pipe; June 6, 2012
- Report AM3191-436934-V:  2012 Long Range Guided Wave Ultrasonic Pipe Screening Results; December 11, 2012
- Report AM3501-475664:  2013 Long Range Guided Wave Ultrasonic Pipe Screening Results; May 20, 2013
- 3rd Quarter 2013 Program Health Report and CP Rectifier Availability
- Job No. 340600432:  2012 Cathodic Protection System Survey Report; March 2012

## LIST OF ACRONYMS USED

| | |
|---|---|
| AC | Alternating Current |
| ADAMS | Agencywide Document Access Management System |
| ASME | American Society of Mechanical Engineers |
| CAP | Corrective Action Program |
| CCW | Component Cooling Water |
| CDBI | Component Design Bases Inspection |
| CFR | Code of Federal Regulations |
| DG | Diesel Generator |
| DRP | Division of Reactor Projects |
| EC | Engineering Change |
| EPIP | Emergency Plan Implementing Procedure |
| ESW | Emergency Service Water |
| FSAR | Final Safety Analysis Report |
| HVAC | Heating, Ventilation, and Air Conditioning |
| IBEW | International Brotherhood of Electrical Workers |
| IMC | Inspection Manual Chapter |
| IP | Inspection Procedure |
| IR | Issue Report |
| IST | Inservice Testing |
| ksi | kilo-pounds per square inch |
| LER | Licensee Event Report |
| LOCA | Loss of Coolant Accident |
| MS | Main Steam |
| MTO | Margin-to-Overfill |
| MU | Makeup |
| NCV | Non-Cited Violation |
| NEI | Nuclear Energy Institute |
| NRR | Office of Nuclear Reactor Regulation |
| NSIR | Office of Nuclear Security and Incident Response |
| ODCM | Offsite Dose Calculation Manual |
| PARS | Publicly Available Records System |
| PCM | Performance Centered Maintenance |
| PI | Performance Indicator |
| PORV | Power-Operated Relief Valve |
| PTL | Pressure Temperature Limit |
| PTLR | Pressure Temperature Limits Report |
| RCS | Reactor Coolant System |
| RV | Reactor Vessel |
| SDP | Significance Determination Process |
| SGTR | Steam Generator Tube Rupture |
| SPAR | Standardized Plant Analysis Risk |
| SSC | Structure, System, and Component |
| SX | Essential Service Water |
| TI | Temporary Instruction |

| | |
|---|---|
| TS | Technical Specification |
| UFSAR | Updated Final Safety Analysis Report |
| UHS | Ultimate Heat Sink |
| URI | Unresolved Item |
| WO | Work Order |

As a result of the Safety Culture Common Language Initiative, the terminology and coding of cross-cutting aspects were revised beginning in calendar year (CY) 2014. New cross-cutting aspects identified in CY 2014 will be coded under the latest revision to Inspection Manual Chapter (IMC) 0310. Cross-cutting aspects identified in the last six months of 2013 using the previous terminology will be converted to the latest revision in accordance with the cross-reference in IMC 0310. The revised cross-cutting aspects will be evaluated for cross-cutting themes and potential substantive cross-cutting issues in accordance with IMC 0305 starting with the CY 2014 mid-cycle assessment review.

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Sincerely,

***/RA/***

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

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

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Letter to Michael Pacilio from Eric Duncan dated February 3, 2014

SUBJECT: BYRON STATION, UNITS 1 AND 2, NRC INTEGRATED INSPECTION REPORT 05000454/2013005; 05000455/2013005

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