UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
2100 RENAISSANCE BLVD., SUITE 100
KING OF PRUSSIA, PA 19406-2713

May 12, 2016

Mr. Larry Coyle
Site Vice President
Entergy Nuclear Operations, Inc.
Indian Point Energy Center
450 Broadway, GSB
Buchanan, NY 10511-0249

SUBJECT: INDIAN POINT NUCLEAR GENERATING – INTEGRATED INSPECTION REPORT 05000247/2016001 AND 05000286/2016001

Dear Mr. Coyle:

On March 31, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Indian Point Nuclear Generating (Indian Point), Units 2 and 3. The enclosed inspection report documents the inspection results, which were discussed on April 29, 2016, with you 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.

This report documents one self-revealing finding and two NRC-identified findings of very low safety significance (Green). These findings involved violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these findings as non-cited violations, consistent with Section 2.3.2.a of the NRC Enforcement Policy. If you contest any non-cited violation in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Senior Resident Inspector at Indian Point. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region I, and the NRC Senior Resident Inspector at Indian Point.

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

Sincerely,

/RA/

Glenn T. Dentel, Chief
Reactor Projects Branch 2
Division of Reactor Projects

Docket Nos. 50-247 and 50-286
License Nos. DPR-26 and DPR-64

Enclosure:
Inspection Report 05000247/2016001 and 05000286/2016001
w/Attachment: Supplementary Information

cc w/encl: Distribution via ListServ

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos.	50-247 and 50-286
License Nos.	DPR-26 and DPR-64
Report Nos.	05000247/2016001 and 05000286/2016001
Licensee:	Entergy Nuclear Northeast (Entergy)
Facility:	Indian Point Nuclear Generating Units 2 and 3
Location:	450 Broadway, GSB Buchanan, NY 10511-0249
Dates:	January 1, 2016, through March 31, 2016
Inspectors:	B. Haagensen, Senior Resident Inspector G. Newman, Resident Inspector S. Rich, Resident Inspector J. Furia, Senior Health Physicist H. Gray, Senior Reactor Inspector J. Patel, Reactor Inspector P. Ott, Operations Engineer
Approved By:	Glenn T. Dentel, Chief Reactor Projects Branch 2 Division of Reactor Projects

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SUMMARY

Inspection Report 05000247/2016001, 05000286/2016001; 01/01/2016 – 03/31/2016; Indian Point Nuclear Generating (Indian Point), Units 2 and 3; Maintenance Risk Assessments and Emergent Work Control and Problem Identification and Resolution.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. The inspectors identified three findings of very low safety significance (Green), which were non-cited violations (NCVs). The significance of most findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," dated April 29, 2015. Cross-cutting aspects are determined using IMC 0310, "Aspects within the Cross-Cutting Areas," dated December 4, 2014. All violations of U.S. Nuclear Regulatory Commission (NRC) requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated February 4, 2015. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 5.

Cornerstone: Initiating Events

- Green. A self-revealing NCV of Technical Specification (TS) 5.4.1, "Procedures," was identified for Entergy's failure to provide adequate guidance in procedure 2-PT-R084C, "23 Emergency Diesel Generator (EDG) Eight-Hour Load Test." Specifically, Entergy failed to provide adequate procedural guidance in order to prevent an overcurrent condition on the 52/3A 480 volt (V) bus normal feeder breaker. As a result, the plant experienced a loss of normal power to their four 480V vital buses and a momentary loss of residual heat removal (RHR) cooling. Entergy wrote condition report (CR)-IP2-2016-01256 and revised the test procedure to add a specific amperage restriction on the vital buses and designate the control indication to be used.

  The finding was more than minor because it is associated with the procedure quality attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown. The performance deficiency caused a loss of normal power to the vital 480V buses, which also resulted in a loss of RHR event. The Region I Senior Risk Analyst (SRA) used IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," to assess the safety significance of this event. The SRA determined that Worksheet 3 in Plant Operating State 1 [reactor coolant system (RCS) closed with steam generators available for decay heat removal], best represents the actual event and associated mitigation system available. Throughout the event, the RCS was intact with steam generators available and 24 reactor coolant pump (RCP) running; therefore, it was determined that this finding was of very low safety significance (Green). This finding had a cross-cutting aspect in the area of Human Performance, Challenge the Unknown, because personnel did not stop when faced with uncertain conditions. Risks were not adequately evaluated and managed before proceeding [H.11 – Challenge the Unknown]. (Section 4OA2)

Cornerstone: Mitigating Systems

- Green. The inspectors identified an NCV of TS 3.7.3, "Main Feedwater Isolation," Surveillance Requirement (SR) 3.7.3.3 on March 26, 2016, when the inspectors determined that Entergy had not conducted surveillance testing on the main boiler feed pump (MBFP) trip function as required. Specifically, the MBFP trip function had never been tested. The MBFP trip is designed to ensure isolation of feedwater flow into containment during a feedline break accident to prevent exceeding pressure and temperature limits inside containment. Entergy wrote CR-IP2-2016-02247 and assigned a mode 3 hold to evaluate the testing to comply with the TS.

  This finding is more than minor because it is associated with the procedural quality attribute of the Mitigating Systems cornerstone because Entergy had not prepared a testing procedure to verify that the surveillance requirements were met. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 3 of IMC 0609, Appendix A, "The Significance Determination Process for Findings at Power," the inspectors determined that a detailed risk evaluation was required because the finding represented a loss of function of a single train for greater than its TS allowable outage time (AOT). The detailed risk evaluation concluded that the finding was of very low safety significance (Green) because of the very low probability of a feedwater line break inside containment when combined with the high probability that the feedwater regulating valve (FRV) and feedwater isolation valve (FWIV) would successfully close from a safety injection signal to isolate feedwater flow into containment. The total core damage contribution of this event is approximately 1E-7 and based on the above considerations, the core damage risk was assessed to be very low or Green. This finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, because Entergy failed to thoroughly evaluate the MBFP failure to trip during a reactor trip to ensure that corrective actions address causes and extent of conditions commensurate with their safety significance [P.2 – Evaluation]. (Section 4OA2)

Cornerstone: Barrier Integrity

- Green. The inspectors identified an NCV of Title 10 of the *Code of Federal Regulations* (10 CFR) 50.65(a)(4) because Entergy did not effectively manage the risk associated with refueling maintenance activities. Specifically, Entergy did not demonstrate they could implement their planned risk management action to restore the containment key safety function within the time-to-boil using the equipment hatch closure plug. Entergy wrote CR-IP2-2016-01503 and CR-IP2-2016-01883 to address this issue.

  This performance deficiency is more than minor because it impacted the barrier performance attribute of the Barrier Integrity cornerstone and affected the objective to provide reasonable assurance that containment protects the public from radionuclide releases caused by accidents or events. Specifically, Entergy did not demonstrate that they could install the hatch plug within the time-to-boil and that the plug would seal the equipment hatch opening, which affected the reliability of containment isolation in response to a loss of shutdown cooling or other event inside containment. The inspectors determined the finding could be evaluated using Attachment 0609.04, "Initial Characterization of Findings." Because the finding degraded the ability to close or isolate the containment, it required review using IMC 0609, Appendix H, "Containment Integrity Significance Determination Process." Since containment status was not intact and the finding occurred when decay

heat was relatively high, it required a phase two analysis. Since the leakage from containment to the environment was less than 100 percent containment volume per day, the finding screens as very low safety significance (Green). A subsequent demonstration showed that the hatch plug provided an adequate seal with the containment hatch opening. The inspectors concluded this finding had a cross-cutting aspect in the area of Human Performance, Documentation, because Entergy did not maintain complete, accurate, and up-to-date documentation related to the use of the hatch plug. Specifically, they tested the seal integrity without using a work order (WO), and made pen-and-ink changes to the procedure without processing a procedure change form.
[H.7 – Documentation] (Section 1R13)

REPORT DETAILS

Summary of Plant Status

Unit 2 began the inspection period at 100 percent power. On February 5, 2016, Unit 2 entered end-of-cycle coast down operations. On March 6, 2016, operators commenced a shutdown, from an initial power of 77 percent, for a planned refueling and maintenance outage (2R22). The station reached mode 6 (refueling) on March 12, 2016, and the reactor was defueled on March 18, 2016. On March 28, 2016, the inspectors verified that all the fuel was safely removed from the reactor vessel and stored in the spent fuel pool. Unit 2 ended the inspection period in a defueled condition.

Unit 3 operated at 100 percent power during the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01 – 1 sample)

Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

The inspectors reviewed Entergy's preparations for the onset of a blizzard with forecasted high winds and heavy snow accumulations on January 23, 2016. The inspectors reviewed the implementation of adverse weather preparation procedures including OAP-48, "Seasonal Weather Preparation (Units 2 and 3)," before the onset of and during this adverse weather condition. The inspectors walked down the outside areas of the site to ensure no challenges from missiles or snow blockage of safety systems air intakes and that there were no problems as a result of the severe weather.

The inspectors verified that plant modifications, maintenance activities (i.e., temporary hazard barrier removal), new evolutions, procedure revisions, or operator workarounds implemented to address periods of adverse weather did not degrade maintenance rule structures, systems, and components (SSCs). The inspectors verified that operator actions defined in Entergy's adverse weather procedure maintained the readiness of essential systems. The inspectors discussed readiness and staff availability for adverse weather response with operations and work control personnel. The inspectors discussed cold weather preparedness with operators and maintained an awareness of cold weather issues throughout the storm. Documents reviewed for each section of this inspection report are listed in the Attachment.

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial System Walkdowns (71111.04Q – 2 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

Unit 2

- 21 and 22 EDGs on January 27, 2016, while 23 EDG was inoperable due to a service water leak
- Safety injection system on February 25, 2016

The inspectors selected these systems based on their risk-significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors reviewed applicable operating procedures, system diagrams, the Updated Final Safety Analysis Report (UFSAR), TSs, WOs, CRs, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have impacted system performance of their intended safety functions. The inspectors also performed field walkdowns of accessible portions of the systems to verify system components and support equipment were aligned correctly and were operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no deficiencies. The inspectors also reviewed whether Entergy had properly identified equipment issues and entered them into the corrective action program (CAP) for resolution with the appropriate significance characterization.

b. Findings

No findings were identified.

.2 Full System Walkdown (71111.04S – 1 sample)

a. Inspection Scope

On March 8 and March 15, 2016, the inspectors performed a complete system walkdown of accessible portions of the Unit 3 auxiliary feedwater (AFW) system to verify the existing equipment lineup was correct. The inspectors reviewed operating procedures, surveillance tests, drawings, equipment line-up check-off lists, and the UFSAR to verify the system was aligned to perform its required safety functions. The inspectors also reviewed electrical power availability, component lubrication and equipment cooling, hanger and support functionality, and availability of support systems. The inspectors performed field walkdowns of accessible portions of the systems to verify system configuration matched plant documentation and that system components and support equipment remained operable. The inspectors confirmed that systems and components were installed and aligned correctly, free from interference from temporary services or isolation boundaries, environmentally qualified, and protected from external threats. The inspectors also examined the material condition of the components for degradation and observed operating parameters of equipment to verify that there were no deficiencies. The inspectors discussed identified deficiencies with the system

engineer to verify they had been appropriately documented. Additionally, the inspectors reviewed a sample of related CRs and WOs to ensure Entergy appropriately evaluated and resolved any deficiencies.

b. Findings

No findings were identified.

1R05 Fire Protection

Resident Inspector Quarterly Walkdowns (71111.05Q – 6 samples)

a. Inspection Scope

The inspectors conducted tours of the areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that Entergy controlled combustible materials and ignition sources in accordance with administrative procedures. The inspectors verified that fire protection and suppression equipment was available for use as specified in the area pre-fire plan (PFP), and passive fire barriers were maintained in good material condition. The inspectors also verified that station personnel implemented compensatory measures for out of service, degraded, or inoperable fire protection equipment, as applicable, in accordance with procedures.

Unit 2

- Fuel support building, 70-foot, 80-foot, and 95-foot elevations (PFP-217 was reviewed) on March 23, 2016
- Vapor containment 95-foot elevation (PFP-203 was reviewed) on March 23, 2016
- Vapor containment 46-foot and 68-foot elevations (PFP-201 and PFP-202 were reviewed) on March 23, 2016

Unit 3

- Component cooling pumps (PFP-306A was reviewed) on March 16, 2016
- RHR pump area, primary auxiliary building (PAB) 15′-0″ (PFP-304 was reviewed), on March 24, 2016
- AFW building (PFP-365, PFP-366, and PFP-367 were reviewed) on March 25, 2016

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06 – 2 samples)

.1 Internal Flooding Review

a. Inspection Scope

The inspectors reviewed the UFSAR, the site flooding analysis, and plant procedures to assess susceptibilities involving internal flooding. The inspectors also reviewed the CAP to determine if Entergy identified and corrected flooding problems and whether operator actions for coping with flooding were adequate. In particular, the inspectors focused on the Unit 2 RHR rooms in the PAB to verify the adequacy of equipment seals located below the flood line, floor and penetration seals, common drain lines, sumps, and sump pumps.

b. Findings

No findings were identified.

.2 Annual Review of Cables Located in Underground Bunkers/Manholes

a. Inspection Scope

The inspectors conducted an inspection of underground bunkers/manholes subject to flooding that contain cables whose failure could disable risk-significant equipment on March 31, 2016. The inspectors observed the inspection and dewatering of manholes 31, 31A, and 31B containing service water pump cables, to verify that the cables were not submerged in water, that cables and splices appeared intact, and to observe the condition of cable support structures.

b. Findings

No findings were identified.

1R08 Inservice Inspection (ISI) Activities (71111.08P – 1 sample)

a. Inspection Scope

From March 14–24, 2016, the inspectors conducted an inspection and review of Entergy's implementation of ISI program activities for monitoring degradation of the RCS boundary, risk significant piping and components, steam generator tube integrity, and vessel internals during the Unit 2 refueling outage (RFO) 2R22. The sample selection was based on the inspection procedure objectives and risk priority of those pressure retaining components in systems where degradation would result in a significant increase in risk. The inspectors observed in-process non-destructive examinations (NDEs), reviewed documentation, and interviewed Entergy personnel to verify that the NDE activities performed as part of the fourth interval, Unit 2 ISI program, were conducted in accordance with the requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, 2001 Edition, 2003 Addenda, and augmented program guidelines.

Nondestructive Examination and Welding Activities (IMC Section 02.01)

Reviews and inspection were completed to verify whether the examinations were performed in accordance with procedures that implemented ASME, Section XI, requirements and that the results were reviewed and evaluated by certified ASME level III personnel. The inspectors performed direct observations of NDE activities in process and reviewed work instruction packages and records, including both documentation and video of NDEs listed below:

ASME Code Required Examinations

- Observation and record review of the work package, drawings, and procedure for the manual volumetric ultrasonic examination (UT) of the ASME Class 1 inner radius of three nozzle to head areas on the pressurizer
- Review of the computer based UT and scope of eddy current testing (ECT) examinations of the four reactor coolant cold leg and hot leg nozzle to safe end dissimilar metal welds completed underwater from the internal root surfaces
- Review of the computer based UT procedures and a sample of the reactor pressure vessel nozzle to shell, circumferential and longitudinal welds, UT results completed as part of the 10-year ASME code required by reactor pressure vessel examinations
- Review of the procedure and observation of UT of the upper shell to pressurizer head weld
- Review of the procedure and preparations for magnetic particle examination of the support skirt to pressurizer lower head weld

The inspectors sampled qualification certificates of the NDE examiners performing the nondestructive testing.

Other Augmented or Industry Initiative Examinations

The inspectors reviewed Entergy procedure CEP-NDE-0504, “Ultrasonic Examination of Small Bore Diameter Piping for Thermal Fatigue Damage,” for manual UT of small diameter piping to detect thermal fatigue in accordance with Materials Reliability Project (MRP)-24 and MRP-146. The inspectors further reviewed the WOs with the UT technician performing the examinations to verify whether the activities were conducted in accordance with the procedure. WOs 00390796, 00390797, and 00390798 were reviewed for the UT of small diameter piping of charging system line segments 82, 83, and 84 in the vicinity of welds 56-3 through 56-8.

A sample of the ECT at the bottom head to instrumentation penetration welds was reviewed by the inspectors to determine the condition of these welds and to confirm these examinations were completed in accordance with the Entergy augmented inspection program and procedures.

The inspectors reviewed the UT data acquisition and analysis process for the baffle-former bolts and observed portions of the remote visual observation of baffle-former plates, baffle-edge bolts, and baffle-former bolts. The inspectors reviewed a sample of Entergy’s evaluation of the data and the results to determine whether these

activities were performed in accordance with Entergy augmented inspection program and procedures as part of the MRP-227-A vessel internals inspection and evaluation process.

The inspectors reviewed event report 51829, dated March 29, 2016, in which Entergy notified the NRC that the level of degradation of baffle-former bolts was a condition not previously analyzed. For the visual observations of 31 baffle-former bolts with locking bar or nonconforming bolt head positions and the 182 bolts with UT indications, additional information is necessary to determine the significance of these conditions and whether there was a performance deficiency. The inspectors concluded that additional information and inspection is needed to determine whether there is a performance deficiency. As a result, the NRC opened an unresolved item (URI).

Review of Previous Indications

The examination preparations and results of the UT of previously identified NDE indications on control rod drive mechanism (CRDM) 52 welds was reviewed. This examination of a previously identified indication verified that that no changes had occurred.

Repair/Replacement Consisting of Welding Activities

Repair/replacement activities on the service water system, including welding and control of welding, were reviewed during this inspection. These included the 21 component cooling water heat exchanger inlet, the 24 fan coil unit motor cooler return, and the instrument air heat exchanger supply.

For the flex modification on WO-00375991-01 welds FW-1, 5, and 7, the radiographs done per Entergy procedure CEP-NDE-0255, “Radiographic Examination,” were reviewed.

Pressurized-Water Reactor Vessel Upper Head Penetration Inspection Activities (IMC 02.02)

The inspectors verified that the reactor vessel upper head penetration J-groove weld examinations were performed in accordance with requirements of 10 CFR 50.55a and ASME Code Case N-729-1, “Alternative Examination Requirements for Pressurized Water Reactor Vessel Upper Heads,” to ensure the structural integrity of the reactor vessel head pressure boundary. The inspectors also observed portions of the remote bare metal VT on the exterior surface of the reactor vessel upper head and CRDM nozzle penetrations to verify that no boric acid leakage or wastage had been observed.

This included observation of the automatic computer based volumetric UT of the reactor vessel upper head penetration nozzles in the vicinity of the CRDM to head welds, including a specific review of the past and present condition of CRDMs 50 and 52.

The inspectors reviewed the ECT performed on outer diameter weld toe to tube area of CRDM 50.

The inspectors further reviewed the work package instructions, procedure for liquid penetrant surface examinations, and final visual record of the outer diameter weld toe to

tube area of CRDM 50 to confirm the material surface condition met the "penetrant white" required condition.

Boric Acid Corrosion Control Inspection Activities (IMC Section 02.03)

During the plant shutdown process, the NRC resident inspectors observed the boric acid leakage identification process. A region based inspector reviewed the boric acid corrosion control program, which was performed in accordance with Entergy procedures and discussed the program requirements with the boric acid program owner. The inspectors reviewed photographic inspection records of a sample of identified boric acid leakage locations and discussed the mitigation and evaluation plans. The inspectors reviewed a sample of CRs for evaluation and disposition within the CAP. Samples selected were based on component function, significance of leakage, and location where direct leakage or impingement on adjacent locations could cause degradation of safety system function.

Steam Generator Tube Inspection Activities (IMC Section 02.04)

The inspectors reviewed an assessment of the pre-RFO 2R22 operational conditions and applicable operational experience of the steam generators that summarized the basis for not examining the steam generator tubes by ECT during 2R22 as was expected based on the ECT results at the last steam generator tube examinations.

Identification and Resolution of Problems (IMC Section 02.05)

The inspectors verified that ISI related problems and nonconforming conditions were properly identified, characterized, and evaluated for disposition within the CAP.

b. Findings

Introduction. The inspectors determined the level of degradation of baffle-former bolts reported to the NRC as a condition not previously analyzed was an issue of concern that warrants additional inspection to determine whether there is a performance deficiency. As a result, the NRC opened a URI.

Description. Additional inspection is warranted to determine whether a performance deficiency exists related to event number 51829 dated March 29, 2016, in which Entergy reported to the NRC that the level of degradation of baffle-former bolts was a condition not previously analyzed. The baffle-former bolts secure plates in the reactor core barrel to form a shroud around the fuel core. The inspectors planned to review the results of Entergy's cause evaluation of this issue. **(URI 05000247/2016001-01, Baffle-Former Bolts with Identified Anomalies)**

1R11 Licensed Operator Requalification Program (71111.11Q – 4 samples)

Unit 2

.1 Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed Unit 2 licensed operator simulator training on March 3, 2016, which included a plant startup from 0 to 25 percent power, main turbine startup, main generator startup, and synchronization to the grid. Component/instrument failures included the loss of the 21 MBFP, a steam flow instrument channel failed high, a steam dump valve failed open, a pressurizer pressure instrument failed high, and a turbine control valve failed open. The inspectors evaluated operator performance during the simulated event and verified completion of risk significant operator actions, including the use of abnormal and emergency operating procedures. The inspectors assessed the clarity and effectiveness of communications, implementation of actions in response to alarms and degrading plant conditions, and the oversight and direction provided by the control room supervisor. Additionally, the inspectors assessed the ability of the crew and training staff to identify and document crew performance problems.

b. Findings

No findings were identified.

.2 Quarterly Review of Licensed Operator Performance in the Main Control Room

a. Inspection Scope

The inspectors observed and reviewed Unit 2 power reduction and plant shutdown for RFO 2R22 conducted on March 6 and 7, 2016. The inspectors observed infrequently performed test or evolution briefings, pre-shift briefings, and reactivity control briefings to verify that the briefings met the criteria specified in Entergy's administrative procedure EN-OP-115 "Conduct of Operations." Additionally, the inspectors observed test performance to verify that procedure use, crew communications, and coordination of activities between work groups similarly met established expectations and standards.

b. Findings

No findings were identified.

Unit 3

.3 Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed Unit 3 licensed operator simulator training during a January 20, 2016, emergency planning drill, which included a large break loss of coolant accident with subsequent loss of offsite power. The inspectors evaluated operator performance during the simulated event and verified completion of risk significant operator actions,

including the use of abnormal and emergency operating procedures. The inspectors assessed the clarity and effectiveness of communications, implementation of actions in response to alarms and degrading plant conditions, and the oversight and direction provided by the control room supervisor. The inspectors verified the accuracy and timeliness of the emergency classification made by the shift manager and the TS action statements entered by the shift technical advisor. Additionally, the inspectors assessed the ability of the crew and training staff to identify and document crew performance problems.

b. Findings

No findings were identified.

.4 Quarterly Review of Licensed Operator Performance in the Main Control Room

a. Inspection Scope

The inspectors observed Unit 3 control room operator response to rising temperature indication on the pressurizer power operated relief valve line on March 14, 2016. The inspectors verified that alarm response procedure use, crew communications, and monitoring of plant parameters met established expectations and standards. The crew confirmed that the power operated relief valves remained closed, that there were no indications of leakage on the acoustic monitors, and that the temperature eventually returned to normal. The inspectors also verified that the unexpected alarm was documented appropriately in CR-IP3-2016-00746.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12Q – 1 sample)

a. Inspection Scope

The inspectors reviewed the sample listed below to assess the effectiveness of maintenance activities on SSC performance and reliability. The inspectors reviewed CAP documents, maintenance WOs, and maintenance rule basis documents to ensure that Entergy was identifying and properly evaluating performance problems within the scope of the maintenance rule. For each SSC sample selected, the inspectors verified that the SSC was properly scoped into the maintenance rule in accordance with 10 CFR 50.65 and verified that the (a)(2) performance criteria established by Entergy was reasonable. Additionally, the inspectors ensured that Entergy was identifying and addressing common cause failures that occurred within and across maintenance rule system boundaries.

Unit 2

- The inspectors reviewed the failure of the 11 station air centrifugal air compressor after planned maintenance, associated (a)(1) evaluation, and performed a system

review to ensure the effectiveness of maintenance activities. The inspectors reviewed past planned and corrective maintenance on the 11 centrifugal air compressor to verify it had been performed in accordance with work instructions.

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 3 samples)

a. Inspection Scope

The inspectors reviewed station evaluation and management of plant risk for the maintenance and emergent work activities listed below to verify that Entergy performed the appropriate risk assessments prior to removing equipment for work. The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that Entergy performed risk assessments as required by 10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When Entergy performed emergent work, the inspectors verified that operations personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work and discussed the results of the assessment with the station's probabilistic risk analyst to verify plant conditions were consistent with the risk assessment. The inspectors also reviewed the TS requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

Unit 2

- Yellow risk for 22 EDG unplanned maintenance on March 3, 3016
- Yellow risk for containment closure during decreased inventory on March 9, 2016

Unit 3

- Yellow fire risk due to Wide Range Nuclear Instrument N38 inoperable on February 22, 2016

b. Findings

Introduction. The inspectors identified an NCV of very low safety significance (Green) of 10 CFR 50.65(a)(4) because Entergy did not effectively manage the risk associated with refueling maintenance activities. Specifically, Entergy did not demonstrate they could implement their planned risk management action to restore the containment key safety function within the time-to-boil using the equipment hatch closure plug.

Description. For both Unit 2 and Unit 3, once the reactor is in the cold shutdown mode, Entergy staff remove the equipment hatch from containment. The equipment hatch opening is approximately 16 feet in diameter, located at ground level, and allows the easy passage of material into and out of containment. The equipment hatch must be moved using the polar crane and can be replaced in a few hours. Shortly after the start of the outage, the time-to-boil upon loss of cooling in the RCS can be very short (approximately 20 minutes) due to the high decay heat load from the fuel in the vessel.

In order to reduce the risk of a release of radioactive steam as a result of a loss of shutdown cooling, Entergy uses an equipment hatch closure plug (hatch plug) that can be installed more rapidly than the equipment hatch. Before the start of RFO 2R22, Entergy staff moved the hatch plug from the storage warehouse to the hill just outside the equipment hatch opening. If needed, Entergy staff use a forklift to move the hatch plug into the equipment hatch opening, engage strong-backs that hold the hatch plug in place, and inflate a pair of tire-like rubber seals that circle the hatch plug. Both Unit 2 and Unit 3 use the same hatch plug.

Entergy's outage risk assessment team (ORAT) report for RFO 2R22 evaluates the risk of each key safety function for each day of the outage. Whenever the equipment hatch is removed and fuel is still in the reactor vessel, the ORAT report credits a number of risk management actions to provide sufficient compensation for the degradation of the containment key safety function. One of them is C4.A5, which states, "Maintain the ability to … install the temporary hatch plug … installation of the hatch plug demonstrated to not approach time to boil, if to be removed with pressurizer level less than 10 percent." To achieve that risk management action, Entergy performs procedure 0-CON-401-EQH, Section 4.5, Equipment Hatch Closure Plug Installation Practice Steps, during both the day shift and the night shift. Each crew is required to demonstrate the ability to install the hatch plug in less than the calculated time to boil, thereby ensuring that the risk management action is established.

During 2R22, on March 9, 2016, both the day shift crew and the night shift crew demonstrated successful hatch plug installation. Upon review of the completed procedure, the inspectors noted that Entergy did not inflate the seals on the plug, as required by step 4.5.11. Instead, the outage control center directed the crew to simulate performing the step. By simulating the step, Entergy failed to demonstrate that they could fully install the hatch plug within the time-to-boil and failed to demonstrate that the hatch plug would seal the hatch as designed. Entergy documented the discrepancy in CR-IP2-2016-01503 and CR-IP2-2016-01883.

During interviews, Entergy staff told the inspectors that they typically do not inflate the seals during the installation demonstration, and the inspectors confirmed this by a review of completed WOs from prior RFOs on both Unit 2 and Unit 3. Several of those WOs included a note or a pen-and-ink change to the procedure stating that the seals were not inflated as directed by step 4.5.11. Entergy staff stated that they inflate the seals (to an undetermined pressure) before taking the plug out of the warehouse to verify they will hold air but do not use a WO, so there is no record of the test or pressure used. Additionally, inflating the seals when the hatch plug is not in the equipment hatch opening does not demonstrate that the hatch plug will seal the containment opening or will hold full pressure.

Entergy began RFO 2R22, entered mode 5 (cold shutdown), and removed the equipment hatch on March 7, 2016. Pressurizer water level had been reduced below 10 percent on March 10, 2016, without fully demonstrating that the hatch plug could be successfully installed in less than the time-to-boil. On April 5, 2016, the inspectors observed as Entergy performed section 4.8 of 0-CON-401-EQH and partially demonstrated that the hatch plug could be installed, the seals inflated, and the seals functioned to seal the containment opening. This partial demonstration was only performed on Unit 2. The hatch plug was last successfully tested in Unit 3 in 2011. Since the same hatch plug and procedure are used for both units, it is reasonable to

conclude that the installation would be successful on Unit 3 as well because there is no indication of significant degradation of the Unit 3 equipment hatch opening in the last five years.

Section 4.8 of 0-CON-401-EQH is used for general-purpose installation of the hatch plug, and so it does not require timing the installation like section 4.5. The supervisor informally timed the evolution and resulting time had margin to the time-to-boil on March 9, 2016. However, there was variability between the conditions during the partial demonstration and the conditions during the timed installation tests. Therefore, it was not conclusively demonstrated whether the hatch plug could have been installed within the time to boil during 2R22.

<u>Analysis</u>. With the containment equipment hatch removed and the pressurizer level below 10 percent, Entergy did not adequately implement their risk management action to ensure they could promptly restore the containment key safety function. Specifically, they did not demonstrate that the hatch plug could be effectively installed and did not obtain a representative time for the installation to ensure it could be installed within the time-to-boil for a loss of shutdown cooling. This was a performance deficiency that was within their ability to foresee and correct and should have been prevented. This performance deficiency is more than minor because it impacted the barrier performance attribute of the Barrier Integrity cornerstone and affected the objective to provide reasonable assurance that containment protects the public from radionuclide releases caused by accidents or events. Specifically, Entergy did not demonstrate that they could install the hatch plug within the time-to-boil and that the plug would seal the equipment hatch opening, which affected the reliability of containment isolation in response to a loss of shutdown cooling or other event inside containment. The inspectors evaluated the finding using Attachment 0609.04, "Initial Characterization of Findings." Because the finding degraded the ability to close or isolate the containment, it required review using IMC 0609, Appendix H, "Containment Integrity Significance Determination Process." Since containment status was not intact and the finding occurred when decay heat was relatively high, it required a phase two analysis. Since the leakage from containment to the environment was less than 100 percent containment volume per day, the finding screens as very low safety significance (Green). A subsequent demonstration showed that the hatch plug provided an adequate seal with the containment hatch opening.

The inspectors concluded this finding had a cross-cutting aspect in the area of Human Performance, Documentation, because Entergy did not maintain complete, accurate, and up-to-date documentation related to the use of the hatch plug. Specifically, they initially tested the seal integrity without using a WO or test procedure (by pressurizing the seal in the warehouse) and subsequently made pen-and-ink changes to the procedure in use during the initial partial demonstration without processing a procedure change form. [H.7 – Documentation]

<u>Enforcement</u>. 10 CFR 50.65(a)(4) states that before performing maintenance activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to this, Entergy did not effectively manage the risk associated with refueling maintenance activities. Specifically, Entergy did not adequately implement their risk management action to ensure they could promptly restore the containment key safety function. Entergy wrote CR-IP2-2016-01503 and CR-IP2-2016-01883 to address this. Because this violation was of very low safety significance and was entered into the CAP, this violation is being treated as an NCV,

consistent with section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000247 and 05000286/2016001-02, Failure to Adequately Implement Risk Management Actions for the Containment Key Safety Function)**

1R15 Operability Determinations and Functionality Assessments (71111.15 – 4 samples)

a. Inspection Scope

The inspectors reviewed operability determinations for the following degraded or non-conforming conditions:

Unit 2

- 21 component cooling water heat exchanger through-wall leak (CR-IP2-2015-05358) on January 20, 2016
- Equipment qualification during coast-down (CR-IP2-2015-03115) on February 17, 2016
- Failed pipe restraint SR-48 on refueling water storage tank common supply line 155 to safety injection and RHR pumps (CR-IP2-2016-01025) on February 25, 2016
- 23 EDG voltage anomalies (CR-IP2-2016-01430) on March 7, 2016

The inspectors selected these issues based on the risk significance of the associated components and systems. The inspectors evaluated the technical adequacy of the operability determinations to assess whether 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 TSs and UFSAR to Entergy's evaluations to determine whether the components or systems were operable. The inspectors confirmed, where appropriate, compliance with bounding limitations associated with the evaluations. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled by Entergy.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18 – 1 sample)

Temporary Modification

a. Inspection Scope

The inspectors reviewed a temporary modification on Unit 3. On March 1, 2016, Entergy performed an emergency temporary modification to reactor protective system (RPS) block relay 15-B in an energized position after they found it de-energized during surveillance testing. The inspectors reviewed the use of the relay blocking device to determine whether the modification affected the safety function of the RPS. The inspectors reviewed 10 CFR 50.59 documentation and engineering change 63282 once it was completed to verify that the temporary modification did not degrade the design

bases, licensing bases, and performance capability of RPS. The inspectors also reviewed associated standing orders, temporary procedure changes, and affected drawings to ensure the modification was appropriately documented.

b. Findings and Observations

Introduction. The inspectors identified that Entergy conducted testing on the Unit 3 RPS that was not described in the UFSAR without performing an adequate 50.59 evaluation, contrary to EN-LI-100, "Process Applicability Determination." Specifically, Entergy made temporary changes to the Unit 3 reactor coolant temperature channel functional test procedures, pressurizer pressure loop functional test procedures, and nuclear power range channel axial offset calibration procedures to use jumpers to bypass RPS trip functions. As a result, the NRC opened an URI related to this concern.

Description. On October 21, 2014, Entergy implemented temporary procedure changes to three sets of reactor protection system surveillance procedures. These procedures were 3-PT-Q87A, B, and C, "Channel Functional Test of Reactor Coolant Temperature Channel 411, 421, and 431"; 3-PT-Q95A, B, and C, "Pressurizer Pressure Loop P-455, 456, and 457 Functional Test"; and 3-PT-Q109A, B, and C, "Nuclear Power Range Channel N-41, 42, and 43 Axial Offset Calibrations." Entergy made the temporary procedures changes as an interim corrective action following a trip of Unit 3 on August 13, 2014, during reactor protection system surveillance testing when a spurious actuation signal occurred in the channel that was not being tested. Entergy was initially unable to identify and correct the cause of the spurious over-temperature delta temperature (OTDT) channel trip and, therefore, wanted to perform their TS required surveillances without risking another unit trip should another spurious actuation occur in the degraded channel not under test. In each case, the change was to install a jumper at the beginning of the testing to maintain the trip relay in an energized condition for the tested channel of the OTDT trip circuit thereby effectively bypassing the channel in test. Each quarterly test was performed three or four times over the course of approximately ten months. On July 1, 2015, Entergy determined that they had corrected the cause of the spurious OTDT channel trips and removed the temporary procedure changes from the controlled document system. Despite this, on August 12, 2015, Entergy performed the surveillances 3-PT-Q95A, B, and C, Pressurizer Pressure Loop P-455, 456, and 457 Functional Test, which incorporated the temporary procedure changes that had been discontinued.

Operating experience has shown that human error has allowed jumpers to remain installed even after testing is over because there is no obvious indication that the channel is in bypass when a jumper is used. Indian Point is committed to IEEE Standard 279-1971, "Criteria for Protective Systems for Nuclear Power Plants." Section 4.13, Indication of Bypass, requires that any channel placed in a bypass configuration for testing shall have continuous indication in the control room that the channel has been removed from service. These standards preclude the use of jumpers for routine testing. This commitment was further documented in the Safety Evaluation Report for TS Amendment 107 that approved the extension of surveillance testing intervals and approved the use of the bypass feature for testing. Although Unit 3 was not originally built with RPS bypass switches, New York Power Authority had planned to install bypass switches, which would comply with IPEEE 279-1971. Entergy terminated the WO for installation of these switches.

Normally, during the course of RPS channel surveillance testing, the affected channel of the OTDT trip circuit would de-energize the trip relay. If one of the other three redundant RPS channels spuriously de-energized at the same time, the two of four signal RPS trip logic would be satisfied and Unit 3 would trip, as occurred on August 13, 2015. By putting the jumper in place, the affected channel trip relay would remain energized under all conditions, including actual conditions that would require a plant trip on OTDT. During testing, the use of the jumper did not increase the likelihood of a malfunction of an SSC over that previously evaluated in the UFSAR because Unit 3 had received a license amendment (Agencywide Documents Access and Management System (ADAMS) Accession No. ML003779650) that allowed testing a bypassed channel. However, the safety evaluation report for that license amendment stated that, "The licensee further commits that only those instruments whose hardware capability does not require the lifting of leads or installing of jumpers will be routinely tested in bypass." When Unit 3 applied for the license amendment, the intent was to permanently install bypass switches that would allow bypassing a channel and would clearly indicate in the control room that a channel was bypassed. The risk of inadvertently leaving a jumper in place is greater than the risk of inadvertently leaving a channel bypassed using hardware that brings in an alarm in the control room, because the jumper can go unnoticed for a longer period of time since it does not result in clear indication in the control room.

Per procedure EN-LI-100, Entergy performed a 50.59 screening review for these temporary procedure changes. In this screening, they incorrectly determined that the temporary procedure changes did not involve a test not described in the UFSAR, and as a result, did not perform a 50.59 evaluation. Although the UFSAR describes reactor protection system testing by bypassing channels, it specifically does not authorize the use of jumpers to do so. The UFSAR for Unit 3, chapter 7, states, "Test procedures also allow the bistable output relays of the channel under test to be placed in the bypassed mode prior to proceeding with the analog channel test … this may only be done for circuits whose hardware does not require the use of jumpers or lifted leads to be placed in bypass mode." Jumpering out the RPS trip relay in an RPS channel under test created an adverse condition because it removed the automatic trip signal from the RPS logic. Entergy was required to fully evaluate the adverse condition rather than authorize the change under an abbreviated 50.59 screening process.

The inspectors concluded that not performing an adequate 50.59 evaluation was a performance deficiency that was reasonably within Entergy's ability to foresee and correct and should have been prevented. Because Entergy was in the process of performing a retroactive 50.59 evaluation at the end of the inspection period, the inspectors were not able to evaluate if the performance deficiency was more than minor. The inspectors determined that the issues concerning the use of jumpers for RPS testing is an URI pending Entergy completion and NRC review of the 50.59 evaluation. **(URI 05000286/2016001-03, Inadequate Screening of Reactor Protection System Test Method Change)**

1R19 Post-Maintenance Testing (71111.19 – 4 samples)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests for the maintenance activities listed below to verify that procedures and test activities ensured system operability and

functional capability. The inspectors reviewed the test procedure to verify that the procedure adequately tested the safety functions that may have been affected by the maintenance activity, that the acceptance criteria in the procedure was consistent with the information in the applicable licensing basis and/or design basis documents, and that the test results were properly reviewed and accepted and problems were appropriately documented. The inspectors also walked down the affected job site, observed the pre-job brief and post-job critique where possible, confirmed work site cleanliness was maintained, and witnessed the test or reviewed test data to verify quality control hold point were performed and checked, and that results adequately demonstrated restoration of the affected safety functions.

Unit 2

- 21 auxiliary boiler feedwater pump after motor coupling preventative maintenance on January 19, 2016
- Repairs to 21 fan cooler unit through-wall leak on February 1, 2016

Unit 3

- Pressurizer level transmitter LM-461B replacement on January 15, 2016
- Appendix R diesel generator after preventative maintenance on February 24, 2016

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 – 6 samples)

a. Inspection Scope

The inspectors observed performance of surveillance tests and/or reviewed test data of selected risk-significant SSCs to assess whether test results satisfied TSs, the UFSAR, and Entergy’s procedure requirements. The inspectors verified that test acceptance criteria were clear, tests demonstrated operational readiness and were consistent with design documentation, test instrumentation had current calibrations and the range and accuracy for the application, tests were performed as written, and applicable test prerequisites were satisfied. Upon test completion, the inspectors considered whether the test results supported that equipment was capable of performing the required safety functions. The inspectors reviewed the following surveillance tests:

Unit 2

- 2-PT-M021C, EDG 23 Load Test, on January 13, 2016
- 2-PT-R006, Main Steam Safety Valve Setpoint Determination, on March 4, 2016
- 2-PT-R014, Automatic Safety Injection System Electrical Load and Blackout Test, on March 9 and 10, 2016
- 2-PT-26A-DS014, Reactor Coolant Pump Component Coolant Water Supply (Containment Isolation) Valve 797, on March 18, 2016
- 2-PT-R084C, 23 EDG 8-Hour Load Test, on March 23, 2016

Unit 3

- 3-PT-Q120B, 32 ABFT (Turbine Driven) Surveillance and Inservice Test, on January 25, 2016

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06 – 1 sample)

Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine emergency drill for Unit 3 on January 20, 2016, to identify any weaknesses and deficiencies in the classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the simulator and emergency operations facility to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also reviewed the station drill critique to compare inspector observations with those identified by Entergy in order to evaluate Entergy's critique and to verify whether Entergy was properly identifying weaknesses and entering them into the CAP.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Public Radiation Safety and Occupational Radiation Safety

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01 – 3 samples)

a. Inspection Scope

During March 6–10, 2016, the inspectors reviewed Entergy's performance in assessing the radiological hazards and exposure control in the workplace. The inspectors used the requirements in 10 CFR 20, TS, applicable industry standards, and procedures required by TS as criteria for determining compliance.

Radiological Hazards Control and Work Coverage

The inspectors reviewed:

- Ambient radiological conditions during tours of the radiological controlled area, posted surveys, radiation work permits (RWPs), adequacy of radiological controls, radiation protection job coverage, and contamination controls

- Use of electronic personal dosimeters in high noise areas and in high radiation areas (HRA)
- RWPs for work within airborne radioactivity areas
- Airborne radioactivity controls and monitoring, contamination containment integrity, and temporary high-efficiency particulate air ventilation system operation
- Controls for highly activated or contaminated materials stored within spent fuel pools
- Posting and physical controls for HRAs and very HRAs

Radiation Worker Performance

The inspectors reviewed radiation worker performance and radiological problem reports since the last inspection.

Radiation Protection Technician Proficiency

The inspectors reviewed performance of radiation protection technicians and radiological problem reports since the last inspection.

b. Findings

No findings were identified.

2RS2 Occupational ALARA Planning and Controls (71124.02 – 3 samples)

a. Inspection Scope

During March 6–10, 2016, the inspectors assessed performance with respect to maintaining occupational individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspectors used the requirements in 10 CFR 20, TS, applicable industry standards, and procedures required by TS as criteria for determining compliance.

Radiological Work Planning

The inspectors reviewed:

- Work activities ranked by actual exposure that were completed during the last outage
- ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements
- ALARA work planning, use of dose mitigation features, and dose goals
- ALARA evaluations for the use of respiratory protective devices
- Work planning and the integration of ALARA requirements
- Evaluation of person-hour estimates provided by maintenance planning and other groups to the radiation protection group based on actual work activity person-hour results

Verification of Dose Estimates and Exposure Tracking Systems

The inspectors reviewed ALARA work packages, assumptions and basis for the current annual collective exposure estimate, and ALARA procedures to determine the methodology for estimating and tracking collective exposures.

Radiation Worker Performance

The inspectors reviewed radiation worker and radiation protection technician performance during work with respect to the radiological hazards present and the ALARA program requirements.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151 – 4 samples)

RCS Specific Activity (BI01) and RCS Leak Rate (BI02)

a. Inspection Scope

The inspectors reviewed Entergy's submittal for the RCS specific activity and RCS leak rate performance indicators for both Unit 2 and Unit 3 for the period of January 1, 2015, through December 31, 2015. To determine the accuracy of the performance indicator data reported during those periods, the inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7. The inspectors also reviewed RCS sample analysis and control room logs of daily measurements of RCS leakage, and compared that information to the data reported by the performance indicator.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 – 3 samples)

.1 Routine Review of Problem Identification and Resolution Activities

a. Inspection Scope

As required by Inspection Procedure 71152, "Problem Identification and Resolution," the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that Entergy entered issues into the CAP at an appropriate threshold, gave adequate attention to timely corrective actions, and identified and addressed adverse trends. 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 CAP and periodically attended CR review group meetings.

b. Findings

No findings were identified.

.2 Annual Sample: Unit 2 MBFP Failure to Trip Corrective Actions

a. Inspection Scope

The 21 MBFP failed to trip automatically or manually on December 5, 2015, when Unit 2 experienced a reactor trip. Specifically, the 21 MBFP failed to trip automatically or manually from the control room and from the local control panel and the pump discharge valve, BFD-2-21, failed to close. The operators had to manually close the MBFP steam supply valve to stop the pump. The cause of the failure to trip was a contaminated control oil system. Subsequently, the inspectors noted that there was a yellow tag hanging on the hand control switch for the 22 MBFP that stated the pump had to be tripped locally because the remote trip switch in the control room did not function. The inspectors performed an in-depth review of Entergy's evaluation and corrective actions associated with the failures of the Unit 2 MBFP trip function (CR-IP2-2015-05459).

The inspectors assessed Entergy's problem identification threshold, cause analyses, extent of condition reviews, compensatory actions, and the prioritization and timeliness of Entergy corrective actions to determine whether Entergy was appropriately identifying, characterizing, and correcting problems associated with this issue and whether the planned or completed corrective actions were appropriate. The inspectors compared the actions taken to the requirements of Entergy's CAP and 10 CFR 50, Appendix B. In addition, the inspectors performed field walkdowns and interviewed engineering personnel to assess the effectiveness of the implemented corrective actions.

b. Findings and Observations

Introduction. The inspectors identified a Green NCV of TS 3.7.3, "Main Feedwater Isolation," SR 3.7.3.3 on March 26, 2016, when the inspectors determined that Entergy had not conducted surveillance testing on the MBFP trip function as required by SR 3.7.3.3. There was no evidence that the MBFP trip function had ever been tested. The MBFP trip is a design feature that is relied upon in the UFSAR accident analysis to mitigate a feedwater line break inside containment event.

Description. On December 5, 2015, during a reactor trip on Unit 2, the operators identified that the 21 MBFP failed to trip when commanded from the control room. Subsequent efforts to electrically and mechanically trip the pump from the local control panel were unsuccessful. The operators finally stopped the pump by isolating steam to the pump by closing the steam admission valve. In addition, the 22 MBFP had a known degraded condition since the previous RFO that the pump would not trip from the control room; it had to be tripped locally by an operator.

The cause of the 21 MBFP trip was determined to be caused by contaminated control oil. Entergy took corrective action to clean up the control oil system, replace the solenoid valves that open to dump oil pressure to trip the pump, and restored the MBFP to normal operation. Unit 2 was restored to 100 percent power on December 7, 2015. CR-IP2-2016-05459 evaluated the corrective actions and concluded that "all

safety functions associated with a MBFP trip are operable." However, the inspectors questioned whether the post-maintenance test had included end-to-end testing of the MBFP trip function in response to a safety injection engineered safety features actuation system signal. The inspectors recognized that TS 3.7.3, "Main Feedwater Isolation," condition D, required the main feedwater pump trip functions to be operable. SR 3.7.3.3 required a verification of the pump trip function. The inspectors subsequently questioned the basis for concluding that the MBFP trip function was not required.

The inspectors noted that CR-IP2-2015-05459, that reported the 21 MBFP failed to trip when commanded, was initially screened as a category 'B' requiring an apparent cause evaluation (ACE) and was assigned six corrective actions. The screening was later downgraded from a 'B' to an 'NC,' which did not require any causal analysis; and corrective actions 1, 3, 4, and 5 were cancelled without taking any action. The basis for this downgrade in the immediate operability determination was that "all safety functions associated with the 21 MBFP trip were operable."

Further inspection efforts determined that TS 3.7.3, "Main Feedwater Isolation," limiting condition of operation (LCO) 'D' required that if one or more MBFP trips were inoperable, Entergy had an AOT of 72 hours to either restore the MBFP trip to an operable status or trip the MBFP. Furthermore, SR 3.7.3.3 required verification of the MBFP trip function every 24 months. The basis for this SR was to prevent adding excessive energy into the containment structure during a feedline or steam line break inside containment. The closure of the MBFP discharge valves and trip of the MBFP was a redundant design feature to the closure of the FRVs in the UFSAR. TS 3.7.3 bases states in part "…closure of the MBFP discharge valves [alone] does not satisfy the accident analysis assumptions. Therefore, when the MBFP discharge valves close in response to an engineered safety features actuation system signal, the MBFP will automatically trip when the associated MBFP discharge valve moves off its open seat." The inspectors questioned when the MBFP trip function was last tested.

Entergy subsequently determined that the MBFP trip function had never been tested (CR-IP2-2016-02247) and therefore did not qualify for treatment as a missed surveillance under SR 3.0.3. Entergy routinely tested the closure of the MBFP discharge valves but not the associated MBFP trip function. Unit 2 was defueled at the time of discovery on March 26, 2016, and this LCO did not apply at that time. Entergy subsequently placed a mode hold (prohibition to enter mode 3 until corrected) on CR-IP2-2016-02247 corrective actions and is currently evaluating the testing required to restore full compliance with SR 3.7.3.3.

Analysis. The inspectors determined that failing to establish and conduct adequate surveillance testing of the 21 and 22 MBFP trip circuitry as required by TS 3.7.3 was a performance deficiency that was within Entergy's ability to foresee and correct. This finding is more than minor because it is associated with the procedural quality attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, Entergy had not prepared a testing procedure to verify surveillance requirements were met. In accordance with IMC 0609.04, "Initial Characterization of Findings," and Exhibit 3 of IMC 0609, Appendix A, "The Significance Determination Process for Findings at Power," the inspectors determined that a detailed risk evaluation was required because the finding represented a loss of function of a single train for greater than its TS AOT. A

detailed risk evaluation was conducted by a Region I SRA. The NRC risk models do not model a main steam line or feedline break inside of containment without isolation, since the total contribution to core damage is less than one percent. As a result, a qualitative assessment was performed. The loss of the automatic trip of the MBFP, given a steam or feed line break inside of containment, would result in the continuous feeding of hot water into containment causing containment pressure and temperature to rise possibly above the environmental qualification limits. This could impact the functionality of mitigating equipment and instrumentation. The following were the major considerations for the evaluation:

- Unit 2 specific initiating event frequency of the event is relatively low at approximately 4E-4/year
- Isolation of the FRVs, or the FWIVs serves the same function as tripping the MBFP and would likely prevent or minimize containment pressure and temperature rise given the break inside of containment
- NUREG-0933, "Resolution of Generic Safety Issues," Item A-21: Main Steam Line Break Inside Containment – Evaluation of Environmental Conditions for Equipment Qualification (Revision 1), determined that equipment was not expected to fail if temperatures were to rise slightly above the qualification temperatures
- As described in the Indian Point Individual Plant Examination Section 3.1.3.4.2.7, if feedwater isolation is successful, containment over pressure is controlled as long as feed and bleed is successful and containment cooling continues to function.

Given that the total core damage contribution of this event is approximately 1E-7 and based on the above considerations, the core damage risk was assessed to be very low or Green.

This finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, because Entergy failed to thoroughly evaluate the MBFP failure to trip during the reactor trip of December 5, 2015, to ensure that corrective actions address causes and extent of conditions commensurate with their safety significance. Entergy did not adequately evaluate the underlying causes of the 21 MBFT failure to trip when required to ensure that the actions taken to correct the problem identified in CR-IP2-2015-05459 were comprehensive and addressed the underlying issues [P.2]

<u>Enforcement</u>. TS 3.7.3, SR 3.7.3.3, requires the MBFP trip function to be tested once every 24 months in modes 1, 2, and 3. Contrary to this requirement, from original construction until April 1, 2016, SR 3.7.3.3 was not adequately implemented and the MBFPs trip function was not tested. Entergy entered this into their CAP (CR-IP2-2016-02247) and assigned a mode 3 hold requirement to evaluate the testing to comply with SR 3.7.3.3. Because this violation is of low safety significance (Green), and Entergy entered this performance deficiency into their CAP, the NRC is treating this violation as a NCV in accordance with section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000247/2016001-04, Failure to Implement Surveillance Requirement for Main Boiler Feed Pump Trip Function)**

.3 Annual Sample: Review of Root Cause Evaluation and Corrective Actions Associated with the Unit 3 Main Transformer Failure

a. Inspection Scope

The inspectors performed an in-depth review of Entergy's root cause evaluation and corrective actions associated with CR-IP3-2015-02913, documenting the failure of the 31 main transformer. On May 9, 2015, a fault occurred on 31 main transformer, which resulted in an automatic trip of the Unit 3 reactor. Entergy identified that a fault on the transformer caused multiple protective relays to actuate as per design. The 31 main transformer differential phase 'A' and the Unit 3 differential phase 'A' and phase 'B' relays actuated resulting in a turbine trip and reactor trip via main generator primary and back-up lockout relays 86P and 86BU, respectively. As a result of this fault, the transformer tank experienced a rapid increase in pressure. This sudden pressure increase fractured the seam weld between the transformer cover and the side wall, allowing the transformer oil to escape and become ignited. Entergy's immediate corrective action was to replace the failed transformer. On January 6, 2016, Entergy completed the root cause evaluation report for the fault that occurred on the 31 main transformer on May 9, 2015.

The inspectors assessed Entergy's problem identification threshold, causal analyses, technical analyses, extent of condition reviews, operational decision making, and the prioritization and timeliness of corrective actions to determine whether Entergy was appropriately identifying, characterizing, and correcting problems associated with this issue. The inspectors focused on opportunities for Entergy to have identified any earlier degradation of the transformer. The inspectors assessed Entergy's transformer condition monitoring program that included thermography, periodic oil screening, on-line dissolved gas analysis, electrical testing, and periodic maintenance inspection of the transformers.

b. Findings and Observations

No findings were identified.

The inspectors found that Entergy promptly initiated an investigation and chartered a team to determine the root cause of the fault that resulted in the failure of the 31 main transformer. Entergy additionally assessed all potential collateral damage in the vicinity of the failed transformer. Entergy's immediate corrective actions included replacing the failed transformer, bushing apparatus, and portions of the iso-phase duct bus. Entergy also completed an engineering assessment to assess the condition on the other transformers prior to plant restart.

The inspectors determined that Entergy's transformer condition monitoring plan, including thermography, periodic oil screening, on-line dissolved gas analysis, electrical testing, and periodic maintenance inspection was in agreement with the fleet template and Electric Power Research Institute guidance. The inspectors verified that Entergy took appropriate actions for reviewing the data gathered from the condition monitoring to determine if it could have predicted a type of fault that resulted in the May 9, 2015, failure. In addition, the inspectors reviewed documentation associated with this issue, including failure investigation reports, equipment failure evaluation, and interviewed engineering personnel to assess the effectiveness of the implemented and planned

corrective actions and to determine possible common elements among the past transformer failures at Indian Point. A Special Inspection Team and resident inspectors previously reviewed the plant's response to the May 9, 2015, event, including performance of the automatic shutdown systems, safety systems, and the activation of the fire brigade. The review was documented in the Special Inspection Report 05000286/2015010 (ADAMS Accession No. ML15204A499) and in the event follow-up inspection activities in NRC Integrated Inspection Report 05000247/2015002 and 05000286/2015002 (ADAMS Accession No. ML15222A186), Section 4OA3.1.

The inspectors' review of the root cause analysis found that, due to the extent of the damage caused by the event, the exact fault initiating location in the transformer could not be identified. However, data gathered from the disturbance monitoring equipment fault recorder, relay targets, visual inspection of the failed transformer, and detail forensic inspection of coil assemblies and bushing, Entergy determined two possible locations of the initiating fault that caused the rapid pressure increase in the transformer:

- Directly in the high voltage 'A' phase winding
- Within the high voltage 'A' phase bushing (internal to the transformer)

For each of the possible causes, the inspectors determined that Entergy has planned corrective actions to ensure that a new transformer would not be subject to the same conditions. Entergy's corrective actions included adding enhanced testing requirements of main transformers to perform partial discharge testing and requirements to perform additional factory and site acceptance testing for new or currently ordered transformers. The inspectors determined that Entergy's overall response to the issue was commensurate with the safety significance and the actions taken and planned were reasonable to restore the main transformer to service and to ensure degradation did not exist on the remaining transformers.

.4 <u>Annual Sample: Initial and Subsequent Loss of 480V Vital Buses and Loss of RHR Cooling</u>

a. <u>Inspection Scope</u>

The inspectors performed a follow-up inspection for two electrical transients that occurred on March 7, 2016, that both resulted in the loss of normal power to the 480V vital buses and a loss of RHR cooling. The events occurred during cold shutdown operations with the RCS pressurized at 330 psig, RCS temperature at 168°F, and pressurizer level at 95 percent. Both RHR cooling trains were in service and the 24 RCP was in service with all steam generators available for shutdown cooling. Throughout both electrical transients, all steam generators and the 24 RCP remained in service and available for RCS heat removal as the 24 RCP is powered from 6.9 kilovolt (kV) which remained energized from off-site power. The initial loss of normal power to the 480V vital buses resulted from actions taken during the preparation for the performance of 2-PT-R084C, 23 EDG Eight-Hour Load Test. Entergy documented these electrical transients in their CAP with CR-IP2-2016-01256 and CR-IP2-2016-01260 respectively.

The inspectors performed this follow-up inspection and focused on a review of the operator response to the events and Entergy's preliminary corrective actions. The inspectors reviewed completed procedures, CRs, narrative logs, and interviewed the operating crew, test team members, and engineering regarding the event and their

response. The inspectors reviewed the initial classification of the CRs and determined that Entergy was conducting ACEs for both transients in accordance with Entergy's CAP procedure, EN-LI-102.

b. Findings and Observations

On March 7, 2016, Unit 2 experienced two losses of normal power to the 480V vital buses that resulted in a loss of the RHR system. The first loss occurred when 480V vital buses 3A and 6A were inadvertently overloaded during a surveillance test of the 23 EDG. Procedural direction to the operators was not sufficient to prevent this event from occurring. This event is the subject of a Green NCV in the section that follows. The subsequent loss of 480V vital bus power occurred approximately one hour later when the 23 EDG tripped while powering the 6A bus. The cause of this second trip is still under review by Entergy, and the NRC opened an URI to further assess the issue.

Initial Loss of 480V Vital Buses and Loss of RHR Cooling

Introduction. A self-revealing Green NCV of TS 5.4.1, "Procedures," was identified for Entergy's failure to provide adequate guidance in procedure 2-PT-R084C, "23 EDG Eight-Hour Load Test." Specifically, Entergy failed to provide adequate procedural guidance in order to prevent an overcurrent condition on the 480V bus normal feeder breaker. As a result, the plant experienced a loss of normal power to their four 480V vital buses and a loss of RHR cooling.

Description. On March 7, 2016, while operators were cooling down the RCS and raising pressurizer level in preparation for taking the pressurizer solid, the operations test group was performing surveillance procedure 2-PT-084C, "23 EDG Eight-Hour Load Test." At 10:04 a.m., the test group had completed the breaker alignment in accordance with section 4.2. This section cross-tied the 3A and 6A 480V vital buses by closing the 52/3AT6A tie breaker and then opening the 52/6A breaker; normal feed (i.e., offsite power) to the 6A 480V bus. The plant was in cold shutdown (mode 5). Both RHR cooling trains were in service and the 24 RCP was in service with all steam generators available. At approximately 10:10 a.m., the control room received a "switch gear 21 or 22 under-voltage" overhead alarm (SGF 4-6). The operating crew responded to the alarm and stopped the 26 service water pump, which cleared the alarm condition. The operations test group continued performance of the surveillance procedure and at 10:17 a.m. started the 23 EDG in "unit" mode of operation in preparation for subsequent parallel operation with the cross-tied 3A-6A 480V buses. At 10:18 a.m. the 52/3A; 480V bus 3A normal feed breaker tripped open on an overcurrent condition. Because of the electrical lineup required by the 23 EDG load test surveillance, this resulted in the loss of the 3A and 6A 480V buses and initiated the station blackout signal with unit trip logic. That load shed all the 480V vital buses, started all three EDGs, and loaded three of the four vital buses; 5A, 2A, and 6A buses on the 21, 22, and 23 EDGs respectively. The 3A bus was locked out due to the overcurrent trip that occurred on the 3A normal feed breaker. Offsite power was maintained throughout the event.

The operating crew responded to this electrical transient entering 2-AOP-480V-1, "Loss of Normal Power to Any 480V Bus," and 2-AOP-RHR-1, "Loss of RHR." The RHR cooling was restored within three minutes. Throughout the transient, 24 RCP remained in service and available for RCS heat removal as it is powered from 6.9 kV which remained energized from offsite power.

Investigation by Entergy determined that the initial transient initiated by the opening of the 52/3A breaker was caused by an actual overcurrent condition. Entergy determined that the total 6.9 kV current on buses 3 and 6 prior to tying buses was observed to be approximately 280 amps. This equated to approximately 3,940 amps transformed through the station service transformer on the 480V side for buses 3A and 6A. The long delay trip setting for breaker 52/3A is equivalent to 3,600 amps on the primary 480V side. The procedure provided a precaution and limitation that stated that the maximum current for the breaker should be maintained below 3,240 amps (90 percent of the breaker trip setting of 3,600 amps). However, the procedure provided no guidance to the operator as to how to convert current indications at 6.9 kV across the station service transformers into current indications at 480V to ensure this load limit was not exceeded as there was no direct indication of current on the 3A and 6A 480V vital buses. Corrective actions included entering the issue into their CAP (CR-IP2-2016-01256) and revising their procedure to add a more specific amperage restriction and the control room indication to be used to ensure the amperage limitation was met.

Analysis. The inspectors determined that failing to maintain adequate procedural guidance in the surveillance procedure to prevent an overcurrent condition was a performance deficiency that was reasonably within Entergy's ability to foresee and correct and should have been prevented. The finding was more than minor because it is associated with the procedure quality attribute of the Initiating Events cornerstone and adversely affected the cornerstone objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown. The performance deficiency caused a loss of normal power to the vital 480V buses which also resulted in a loss of RHR event. The Region I SRA used IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process," to assess the safety significance of this event. The SRA determined that Worksheet 3, best represented the actual event and associated mitigation systems available. Although not actually relied upon, steam generators remained available and the 24 RCP remained running during the transient to support decay heat removal if shutdown cooling had not been promptly restored. The SRA assumed full equipment credit and operator recovery credit for this finding, resulting in a low E-7 increase in core damage frequency. This finding was of very low safety significance (Green).

This finding had a cross-cutting aspect in the area of Human Performance, Challenge the Unknown, because personnel did not stop when faced with uncertain conditions. Uncertain conditions initially presented themselves to Entergy prior to the start of the 23 EDG eight-hour load test surveillance when the "switch gear 21 or 22 under-voltage" overhead alarm (SGF 4-6) was received before the first transient. Later, the operators were provided with a load limit in the test procedure and did not know how to convert the 6.9 KV bus current loading to 480 V current loading on the vital buses. The operators proceeded on in the test procedure in the face of uncertainty. [Challenge the Unknown - H.11]

Enforcement. Unit 2 TS 5.4.1 requires that adequate written procedures shall be established, implemented, and maintained for procedures referenced in Appendix A of Regulatory Guide 1.33, Revision 2. Appendix A, Section 8.b.1(q), requires specific procedures for emergency power surveillance tests. Contrary to the above, Entergy did not adequately maintain surveillance procedure 2-PT-084C, "23 EDG Eight-Hour Load Test," by failing to include specific steps or precaution detail to preclude an overcurrent condition on the 52/3A; 3A 480V bus normal feed breaker. Corrective actions included

revising their procedure to add a more specific amperage restriction on the vital buses and designating the control room indication to be used to ensure the amperage limitation was met. Because this violation was of very low safety significance (Green) and has been entered into their CAP (CR-IP2-2016-01256), this violation is being treated as an NCV consistent with Section 2.3.2 of the Enforcement Policy. **(NCV 05000247/2016001-05, Failure to Provide Adequate Procedural Guidance in Order to Prevent an Overcurrent Condition)**

Subsequent Loss of 480V Vital Buses and Loss of RHR Cooling

Introduction. Following the initial loss of 480V vital buses and loss of RHR cooling, the operating crew was taking actions to restore normal power to all 480V buses. Before the crew was able to restore off-site power to the 6A bus, the 23 EDG tripped on overcurrent resulting in a loss of bus 6A and the subsequent blackout/unit trip signal that stripped all loads from the remaining 480V buses. The cause of this second trip is still under review by Entergy, and the NRC opened an URI related to this concern to assess whether a performance deficiency exists.

Description. On March 7, 2016, approximately one hour after the trip of the 3A normal feed breaker, the 23 EDG tripped on overcurrent while powering the 6A bus. The operators responded by re-entering 2-AOP-480V-1, “Loss of Normal Power to Any 480V Bus,” and 2-AOP-RHR-1, “Loss of RHR.” The RHR cooling was restored within five minutes. Throughout the transient, 24 RCP remained in service and available for RCS heat removal as it is powered from 6.9 kV which remained energized from offsite power. Due to ongoing performance of restoration actions from the previous trip, the 21 EDG was not ready to automatically start, so initially only the 2A bus loaded on the 22 EDG. The delay in the starting of 21 EDG combined with the associated loss of 23 vital instrument bus resulted in loss of power to the ‘C’ pressurizer level channel which then caused both a loss of letdown and loss of pressurizer heaters. These conditions along with the malfunctioning of the 24 loop pressurizer spray valve controller created additional challenges to the operator tasked with controlling pressurizer pressure and level. The delay in the start of the 21 EDG also affected the operator tasked with restoring RHR as the RHR heat exchanger outlet motor operated valves associated with 21 RHR pump were powered from the 5A bus. The crew was able to restore the 3A bus with the 22 EDG, and then start the 21 RHR pump. The 6A bus remained de-energized until the crew restored 6A via off-site power. The 23 EDG was declared inoperable. By 1:49 p.m., all four 480V buses were restored to off-site power; and by 2:07 p.m., 21 and 22 EDGs had been shut down and returned to standby (auto start) condition.

Entergy’s initial review of the second electrical transient determined the most probable cause was a spurious actuation of the ‘A’, ‘B’, or ‘C’ phase voltage controlled overcurrent relays. These relays were replaced under WO 00440073 with spare, calibrated relays. Operator observations during the event indicated that the 23 EDG breaker tripped while loads were still being added, including the start of the turbine auxiliary bearing oil pump and various motor control centers, but the 23 EDG load never exceeded the continuous load rating of 1750 kilowatt (kW). Local diesel observations indicated approximately 1650 kW load on the 23 EDG just prior to the trip. Entergy then concluded that all other equipment functioned as per design and that a monthly load test surveillance would be utilized to determine operability after replacing the overcurrent relays. On March 8, 2016, 23 EDG was declared operable following successful completion of the monthly diesel surveillance procedure. The 23 EDG was run, closed

onto Bus 6A, and loaded to 2275 kW. Later, as-found bench testing of the overcurrent relays indicated that the relay trip settings were within calibration and should have functioned as designed.

Subsequently, on March 10, 2016, during performance of PT-R14, “Automatic Safety Injection System Electrical Load and Blackout Test,” 23 EDG exhibited anomalous behavior during the train ‘B’ load sequencing. During the test, the voltage on bus 6A dropped to approximately 200V when the 23 AFW pump was sequenced onto the bus (CR-IP2-2016-01430). 23 EDG was again declared inoperable and the period of inoperability was backdated to March 7, 2016, when it originally tripped. Further troubleshooting and additional failure modes analysis found a degraded resistor associated with the 23 EDG automatic voltage regulator. The 23 EDG voltage regulator was replaced, and the 23 EDG was again tested satisfactorily. The low voltage issue exhibited during PT-R14, “Automatic Safety Injection System Electrical Load and Blackout Test,” was documented in CR-IP2-2016-01430 and has been closed in CR-IP2-2016-01260 to be included in the ACE associated with the tripping of 23 EDG breaker on March 7, 2016. Entergy was in the process of performing a failure analysis and an ACE at the end of the inspection period. NRC review of Entergy’s failure analysis and causal evaluation will be performed to evaluate if a performance deficiency exists. The inspectors determined that the issue is an URI. **(URI 05000247/2016001-06, 23 Emergency Diesel Generator Automatic Voltage Regulator Failure)**

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

.1 Plant Events

a. Inspection Scope

For the plant events listed below, the inspectors reviewed and/or observed plant parameters, reviewed personnel performance, and evaluated performance of mitigating systems. The inspectors communicated the plant events to appropriate regional personnel, and compared the event details with criteria contained in IMC 0309, “Reactive Inspection Decision Basis for Reactors,” for consideration of potential reactive inspection activities. As applicable, the inspectors verified that Entergy made appropriate emergency classification assessments and properly reported the event in accordance with 10 CFR 50.72 and 50.73. The inspectors reviewed Entergy’s follow-up actions related to the events to assure that Entergy implemented appropriate corrective actions commensurate with their safety significance.

Unit 2

- Reverse osmosis (RO) skid leak and report of high tritium levels in monitoring wells on February 5, 2016. A description of this event and associated URI is located in section 4OA5 of this report
- Loss of normal power to 480 VAC vital buses and shutdown cooling on March 7, 2016. A description of this event, associated Green NCV, and URI is listed in section 4OA2.4 of this report
- Review of a 10 CFR 50.72 report of degraded core baffle former bolts on March 28, 2016. A description of this event and URI is located in section 1R18 of this report

b. Findings

No findings were identified.

4OA5 Other Activities

Groundwater Contamination

a. Inspection Scope

On February 5, 2016, Entergy notified the NRC of a significant increase in groundwater tritium levels measured at three monitoring wells (MWs)(MW-30, MW-31, and MW-32) located near the Unit 2 Fuel Storage Building (FSB). These samples were drawn on January 26–27, 2016, and analyzed and confirmed on February 2–4, 2016.
The highest concentration was detected at MW-32, which increased from 12,000 pCi/l on January 11, 2016, to 8,100,000 pCi/l on January 26, 2016, and subsequently up to 14,800,000 pCi/l on February 4, 2016. This increased tritium concentration event was documented by Entergy in CR-IP2-2016-00564. The NRC resident inspectors began an immediate review of this incident, and a region-based specialist inspector conducted a walk down of associated Unit 2 radioactive waste drain systems and components on February 11, 2016. The specialist inspector also conducted additional on-site inspection activities on March 6–10, 2016, to review Entergy's continuing investigation into the event. Representatives of New York State Departments of Environmental Conservation and Health and the Environmental Protection Agency, Region II, accompanied portions of these on-site inspection activities.

b. Findings and Observations

Introduction. The inspectors identified an URI related to whether a performance deficiency exists associated with Entergy's controls to prevent the introduction of radioactivity into the site groundwater were adequate. Specifically, Entergy obtained increased tritium concentrations from groundwater MW samples in January 2016 indicating that a leak or spill had occurred allowing the introduction of radioactivity into the subsurface of the site. Entergy entered this issue into their CAP as CR-IP2-2016-00264, CR-IP2-2016-00266, and CR-IP2-2016-00564 with actions to characterize and evaluate this new leak.

Description. The initial Entergy investigation focused on identifying the source of the contamination which was preliminarily determined to originate from the reject water of the RO skid that was in service from January 16–31, 2016. This cause determination was based on the timing of the groundwater contamination event and based on the unique matching of the radionuclide signature from the groundwater samples and the RO skid reject water. Entergy has yet to identify the specific leakage pathway or the root cause for this event. An URI is initiated for further determination of whether a performance deficiency exists following Entergy's finalization of their root cause analysis. **(URI 5000247/2016001-07, January 2016 Groundwater Contamination)**

Observations

Following identification of the increased groundwater tritium, Entergy promptly assembled a dedicated project manager and investigation team that included

representatives of radiation protection, chemistry, operations, engineering, maintenance, hydrogeology contractor, root cause investigation, and CAP staff. The initial Entergy investigation focused on identifying the source of the contamination, which was determined to originate from the reject water of the RO skid that was in service from January 16–31, 2016. The RO skid was used to filter water from the Unit 2 refueling water storage tank and the reject water contains the filter backwash concentrates from that operation. The source determination was based on the timing of the groundwater contamination event and on the unique matching of the radionuclide signature from the groundwater samples and the RO skid reject water concentrated radioactivity. The reject water from the RO skid has a unique radiological signature relative to other sources of water at Unit 2, with a very high concentration of Antimony-125 (Sb-125). In addition to the high tritium levels seen at MW-32, a high concentration of Sb-125 (5540 pCi/l) was detected, with a trace amount (27 pCi/l) of Cobalt-60. Entergy did not report detection of any other isotopes (including Sr-90) in these MWs subsequent to this release. Along with the timing of the RO skid operation and the unique radionuclide comparison match up with the groundwater results, this provides reasonable confidence that the RO skid is the source of the groundwater contamination.

This investigation identified two previous CRs (CR-IP2-2016-00264 and CR-IP2-2016-00266), both initiated on January 17, 2016, which documented a leak and floor ponding observed inside the Unit 2 PAB during the time of the initial operation of the RO skid. On February 5, the resident inspectors conducted a walkdown of the drainage path and on February 11, 2016, NRC inspectors conducted a walk-down of various locations associated with the drainage path from operation of the RO skid, and observed evidence of recent prior spills of water inside the radiological controlled area of the PAB, both on the 35-foot elevation of the PAB (CR-IP2-2016-00264) and in the FSB pump pit (CR-IP2-2016-00266).

Entergy's investigation focused on examination of possible leakage pathways of the RO skid reject water on the drainage flow path from the RO skid located on the 95-foot elevation of the maintenance and outage building (MOB) to the Unit 2 waste hold-up tank (WHUT). This pathway included a floor drain between the MOB and the FSB sump, a temporary hose from the FSB sump to a floor drain, a floor drain to the 15-foot elevation PAB sump, and a pipe from the 15-foot PAB sump to the WHUT. Based on this investigation, Entergy initially identified: 1) at least three partial blockages in the floor drain pathway between the MOB and the WHUT, 2) the FSB 28 sump pump was out of service, resulting in a different drain pathway from the RO skid to the 15-foot elevation PAB sump, and 3) two floor drains from the 51-foot elevation pipe penetration room had been previously cut open for inspection, but not capped or sealed. This resulted in water spilling out of the floor drain piping onto the floor of the 35-foot elevation PAB pipe chase. The evidence of spillage on the 35-foot elevation of the PAB would provide a leak pathway to the groundwater through a seismic gap between the PAB and the Unit 2 containment. This spill elevation is below the elevation monitored by MW-32 (equivalent to the 45-foot elevation), therefore, Entergy continues to investigate an additional higher elevation leakage pathway. This additional leak pathway has not been determined.

Entergy's short-term corrective actions to preclude recurrence of this event included review and inspection of all Unit 2 floor drains to be used during the RFO 2R22. Seventeen partial blockages were identified and cleared prior to the commencement of RFO 2R22. The FSB sump was repaired and placed back in service. The two open

floor drain pipes located above the 35-foot elevation PAB pipe chase were capped. In addition, to reduce the tritium groundwater concentrations in the vicinity of Unit 2, beginning on March 16, 2016, Entergy began pumping water from MW-32 and sending the tritiated water back into the PAB for liquid radioactive waste processing. That action is designed to lower groundwater tritium monitoring well concentrations to normal levels in order to provide sensitivity to detect any new plant leaks.

Entergy's long-term corrective action for reducing tritium levels in the groundwater is the same as previously identified for the March 2014 tritium spike (CR-IP2-2015-03806), the start-up and operation of recovery well 1. Following installation of equipment and system testing, full operation of the recovery well system is scheduled by the end of the summer 2016. This system will allow for the collection of tritiated groundwater to be returned inside the PAB for processing. Entergy's investigation of the current leak event is still ongoing to identify the leakage pathway to groundwater as measured in MW-32 and once complete, the investigation report will be reviewed and assessed during a future inspection.

The NRC assessment of the safety significance of this event focused on validating the safety impact of dose to the public from the release of tritium to the site groundwater, and ultimately to the Hudson River. Two months after detection of the leak in groundwater MW-32, the groundwater tritium contamination from this event has not migrated downstream to the other on-site monitoring wells indicating that the tritium contamination has not yet reached the Hudson River. The NRC verified that Entergy's bounding public dose calculations on the groundwater contamination leak was conservative and a maximum worst case scenario would result in a dose of 0.000112 mrem per year, which represents a very small fraction of the allowable dose (liquid effluent dose objective of 3 millirem per year). This low value is due to groundwater at Indian Point not being a source of any drinking water. There are no drinking water wells on the Indian Point site, groundwater flow from the site is to the Hudson River and not to any near site drinking water wells, and the Hudson River has no downstream drinking water intakes as it is brackish water. Pathways to the public are therefore limited to the consumption of fish and river invertebrates. The inspection determined that there is no safety impact to the public as a result of this groundwater contamination event.

4OA6 Meetings, Including Exit

On April 29, 2016, the inspectors presented the inspection results to Mr. Larry Coyle, Site Vice President, and other members of Entergy. The inspectors verified that no proprietary information was retained by the inspectors or documented in this report.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Entergy Personnel

L. Coyle, Site Vice President
J. Dinelli, Plant Operations General Manager
R. Alexander, Unit 2 Shift Manager
T. Alexander, Operator at the Controls, RO
N. Azevedo, Code Programs Supervisor
J. Baker, Unit 2 Shift Manager
J. Balletta, Unit 2 Control Room Supervisor
K. Baumbach, Chemistry Supervisor
S. Bianco, Operations Fire Marshal
K. Brooks, Unit 2 Assistant Operations Manager
R. Burroni, Engineering Director
T. Chan, Engineering Supervisor
D. Caffery, BOP Operator, RO
T. Cramer, Unit 3 Shift Manager
D. Dewey, Assistant Operations Manager
J. Dignam, Unit 3 Control Room Supervisor
R. Dolansky, ISI Program Manager
R. Drake, Civil Design Engineering Supervisor
B. Durr, Shift Outage Manager
P. Egan, Unit 2 Control Room Supervisor
K. Elliott, Fire Protection Engineer
J. Ferrick, Production Manager
L. Frink, ALARA Supervisor
M. Fritz, Unit 3 Reactor Operator
D. Gagnon, Security Manager
R. Gioggia, System Engineer
L. Glander, Emergency Preparedness Manager
Ed Goetchius, Instructor, Ops Sr. Staff Nuclear
J. Graham, Unit 3 Shift Manager
W. Guerrier, Unit 3 Nuclear Plant Operator
J. Hill, Supervisor, Engineering
J. Johnson, Unit 2 Control Room Supervisor
M. Johnson, Unit 3 Shift Manager
A. Kaczmarek, Engineering Supervisor, Engineering
F. Kich, Performance Improvement Manager
A. King, Senior Lead Nuclear Engineer
J. Kirkpatrick, Regulatory and Performance Improvement Director
C. Kocsis, Senior Operations Instructor
P. Labuda, Unit 2 Reactor Operator
N. Lizzo, Training Manager
G. Leveque, Maintenance Planner
M. Lewis, Assistant Operations Manager
R. Louie, 95' Hill Coordinator
D. Martin, Unit 2 Control Room Supervisor
G. Martin, Unit 2 Reactor Operator
R. Martin, Senior Project Manager
D. Mayer, Unit 1 Director

B. McCarthy, Operations Manager
K. McKenna, Unit 2 Shift Manager
F. Mitchell, Radiation Protection Manager
R. Montross, Unit 2 Shift Manager
E. Mullek, Maintenance Manager
G. Norton, Instructor, Operations Senior Staff
T. Oggeri, Unit 3 Control Room Supervisor
J. Ready, Unit 2 Field Support Supervisor
K. Robinson, Lead Controller, Senior Emergency Planner
S. Ryan, Unit 2 Control Room Supervisor
T. Salentino, Vapor Containment Coordinator
C. Smyers, Manager, Chemistry
T. Soohoo, Junior Nuclear Electrical Technician
D. Sparozic, System Engineer
S. Stevens, Radiation Protection Operations Superintendent
C. Stuart, Unit 3 Nuclear Plant Operator
M. Tesoriero, System Engineering Manager
M. Troy, Nuclear Oversight Manager
B. Ulrich, Unit 2 Control Room Supervisor
J. Varga, Reactor Operator
R. Walpole, Regulatory Assurance Manager

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Opened

05000247/2016001-01	URI	Baffle-Former Bolts with Identified Anomalies (Section 1R08)
05000286/2016001-03	URI	Inadequate Screening of Reactor Protection System Test Method Change (Section 1R18)
05000247/2016001-06	URI	23 Emergency Diesel Generator Automatic Voltage Regulator Failure (Section 4OA2)
05000247/2016001-07	URI	January 2016 Groundwater Contamination (Section 4OA5)

Opened/Closed

05000247/05000286/ 2016001-02	NCV	Failure to Adequately Implement Risk Management Actions for the Containment Key Safety Function (Section 1R13)
05000247/2016001-04	NCV	Failure to Implement Surveillance Requirement for Main Boiler Feed Pump Trip Function (Section 4OA2)
05000247/2016001-05	NCV	Failure to Provide Adequate Procedural Guidance in Order to Prevent an Overcurrent Condition (Section 4OA2)

LIST OF DOCUMENTS REVIEWED

Common Documents Used

Indian Point Unit 2, Updated Final Safety Analysis Report
Indian Point Unit 2, Individual Plant Examination
Indian Point Unit 2, Individual Plant Examination of External Events
Indian Point Unit 2, Technical Specifications and Bases
Indian Point Unit 2, Technical Requirements Manual
Indian Point Unit 2, Control Room Narrative Logs
Indian Point Unit 2, Plan of the Day

Section 1R01: Adverse Weather Protection

Procedures
OAP-008, Severe Weather Preparations, Revision 23
OAP-048, Seasonal Weather Preparation, Revision 17

Condition Reports (CR-IP2-)
2016-00383 2016-00387 2016-00388

Condition Reports (CR-IP3-)
2016-00243 2016-00246 2016-00247

Section 1R04: Equipment Alignment

Procedures
3-PT-R007A, 31 & 33 ABFPs Full Flow Test, Revision 20
3-PT-R007B, 32 ABFP Full Flow Test, Revision 17
3-SOP-AFW-001, Auxiliary Feedwater System Operation, Revision 9
3-SOP-AFW-002, Auxiliary Feedwater System Support Procedure, Revision 4

Condition Reports (CR-IP3-)
2014-02289 2014-02667 2015-02765 2015-02766 2015-02843 2015-02844
2015-03119 2016-00748

Maintenance Orders/Work Orders

WO 00257935	WO 00297321	WO 00306381	WO 00374110
WO 00395789	WO 00397634	WO 00405016	WO 00413164
WO 00413977	WO 00413979	WO 51421683	WO 52422135
WO 52479901			

Drawings
9321-F-20183, Flow Diagram Condensate & Boiler Feed Pump Suction, Revision 64
9321-F-20173, Flow Diagram Main Steam, Revision 72
9321-F-20193, Flow Diagram Boiler Feedwater, Revision 63

Section 1R05: Fire Protection

Condition Reports (CR-IP2-)
2016-02117

Condition Reports (CR-IP3-)
2016-00825

Miscellaneous
PFP 306A, Component Cooling Pumps – Primary Auxiliary Building, Revision 0
PFP-345, Auxiliary Feedwater Pump Room – Auxiliary Feedwater Building, Revision 15
PFP-366, Chemical Additive Room – Auxiliary Feedwater Building, Revision 13
PFP-304, General Floor Plan – Primary Auxiliary Building, Revision 11

Section 1R06: Flood Protection Measures

Procedures
0-ELC-418-GEN, Manhole Inspections, Revision 5
2-AOP-FLOOD-1, Flooding

Maintenance Orders/Work Orders
WO 52685544

Section 1R08: Inservice Inspection Activities

Procedures
2-PT-R156, RCS Boric Acid Leakage and Corrosion Inspection, Revision 4
2-PT-R203, Visual Examination of Reactor Vessel Head Penetrations and Head Surface for Leakage, Revision 5
CEP-NDE-0255, Radiographic Examination for ASME Welds and Components, ASME XI, Revision 8
CEP-NDE-0404, (PDI UT-1), Manual UT of Ferritic Piping Welds (ASME XI), Revision 5
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CEP-NDE-0485, Manual Ultrasonic Examination of Vessel Nozzle, Inside Radius (Non-App. VIII), Revision 12
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SEP-BAC-IPC-001, Boric Acid Corrosion Control Program, Revision 2
WDI-STD-1040, Ultrasonic Examination of Reactor Vessel Head Penetrations, Revision 12
WDI-STD-1073, Ultrasonic Examination of Baffle-Former Bolts with Welded Lock Bars, Revision 4

Condition Reports (CR-IP2-)

2015-00167	2015-03550	2015-04170	2015-05358	215-05755
2016-01328	2016-01341	2016-01719		

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NRC Information Notice No. 98-11: Cracking of Reactor Vessel Internal Baffle Former bolts in Foreign Plants

Section 1R11: Licensed Operator Requalification Program

Procedures
2-E-0, Reactor Trip or Safety Injection, Revision 6
2-ES-0.1, Reactor Trip Response, Revision 5
2-POP-2.1, Operation at Greater than 45% Power, Revision 62
2-POP-3.1, Shutdown from 45 Percent Power, Revision 57
2-POP-3.2, Plant Recovery from Trip, Hot Standby, Revision 40
2-POP-3.3, Plant Cooldown – Hot to Cold Shutdown, Revision 79
3-ARP-003, Panel SAF – Reactor Coolant System, Revision 49
2-POP-1.3, Plant Startup from Zero to 45% Power, Revision 88
2-AOP-UC-1, Uncontrolled Cooldown, Revision 6
2-AOP-LOAD-1, Excessive Load Increase or Decrease, Revision 6
2-AOP-INST-1, Instrumentation/Controller Failures, Revision 8
2-AOP-FW-1, Loss of Main Feedwater, Revision 13

Condition Reports (CR-IP3-)
2016-00746

Section 1R12: Maintenance Effectiveness

Condition Reports (CR-IP2-)
2014-00397 2014-04458 2015-01939 2016-00064 2016-00109

Maintenance Orders/Work Orders
WO 00326236 WO 00412920 WO 00433939 WO 52596628

Miscellaneous
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Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
IP-SMM-00-104, Attachment 9.2, Shiftly Outage Shutdown Safety Assessment Guidelines, Revision 14
0-CON-401-EQH, Removal and Replacement of 16-Foot Diameter Equipment Hatch Assembly, Revision 10

Condition Reports (CR-IP2-)
2016-01251 2016-01503

Maintenance Orders/Work Orders
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Miscellaneous
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ORAT Report, Revision 1

Section 1R15: Operability Determinations and Functionality Assessments

Procedures
2-PT-R084C, Revision 16, 23 EDG 8 Hour Load Test
2-PT-R084C, Revision 17, 23 EDG 8 Hour Load Test
EN-LI-102, Corrective Action Program
EN-OP-104, Operability Determination Process

Condition Reports (CR-IP2-)
2015-05358 2016-01430 2016-01256 2016-01259 2016-01260 2016-01266
2016-01355 2016-01430 2016-01500

Drawings
Drawing 9321-F-2735-141, Flow Diagram Safety Injection System
Drawing B206725-06, Indian Point Unit 2 Inservice Inspection Isometric of Safety Injection Line Number 155

Miscellaneous
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EC 61758, Evaluation of Through-Wall Leak at 21 Component Cooling Water Heat Exchanger Inlet Weld, Revision 0

Section 1R18: Plant Modifications

Procedures
3-POP-3.1, Plant Shutdown from 45 Percent Power, Revision 48
EN-OP-112, Night and Standing Orders, Revision 2

Condition Reports (CR-IP3-)
2014-01903 2016-00664 2016-00665 2016-00667 2016-00683 2016-00716

Maintenance Orders/Work Orders
WO 52630783 WO 52630629 WO 52630784

Drawings
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113E301, Sheet 3, Reactor Protection System Schematic Diagram, Revision 10

Miscellaneous
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DRN-14-01173
DRN-14-01174
DRN-14-01175
DRN-14-01221
DRN-14-01222
DRN-14-01223

Section 1R19: Post-Maintenance Testing

Procedures
EN-OP-104, Operability Evaluation, Revision 10
EN-FAP-LI-001 Attachment 7.8
PC-OLO3C, Pressurizer Level Loops L-461 and L-462 Channel Calibration, Revision 3

Condition Reports (CR-IP2-)
2015-03550 2015-05728 2015-05764 2015-05755 2016-00435

Maintenance Orders/Work Orders

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WO 52521379	WO 00367766		

Drawings
A236318

Miscellaneous
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FI5565-R-001, LPI Failure Analysis Report, Revision 1
Scientech Bill of Lading #5564 Curtis Wright Certificate of Compliance PO#1045804
TST-PT-R93

Section 1R22: Surveillance Testing

Procedures
2-PT-R094C, 23 EDG 8-Hour Load Test, Revision 16
2-PT-R094C, 23 EDG 8-Hour Load Test, Revision 18
3-PT-Q120B, 32 Auxiliary Boiler Feedwater Pump (Turbine Driven) Surveillance and Inservice Test, Revision 25
2-PT-R006, Main Steam Safety Valve Setpoint Determination, Revision 31

Condition Reports (CR-IP2-)
2015-00237 2016-01204

Condition Reports (CR-IP3-)
2015-06004 2016-00257

Maintenance Orders/Work Orders

WO 52568432	WO 52575711	WO 52646946	WO 52667347
WO 52668028-01			

Section 1EP6: Drill Evaluation

Procedures
3-E-0, Reactor Trip or Safety Injection, Revision 6
3-E-1, Loss of Reactor or Secondary Coolant, Revision 4
3-ES-1.3, Transfer to Cold Leg Recirculation, Revision 9
3-FR-P.1, Response to Imminent Pressurized Thermal Shock, Revision 4
Emergency Action Level, Revision 15-2
EN-EP-306, Drills and Exercises, Revision 7
EN-EP-308, Emergency Planning Critiques, Revision 3

Condition Reports (CR-IP3-)
2015-03588 2016-00218 2016-00231 2016-00232 2016-00233 2016-00252
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Miscellaneous
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All press releases created during the exercise
Exercise Report, dated March 3, 2016
Exercise Scenario, dated February 20, 2016

Section 4OA1: Performance Indicator Verification

Procedures
0-SOP-LEAKRATE-001
3-CY-2325, Radioactive Sampling Schedule, Revision 14
3-CY-2765, Coolant Activity Limits – Dose Equivalent Iodine/Xenon, Revision 5

Condition Reports (CR-IP3-)
2016-00823

Section 4OA2: Problem Identification and Resolution

Procedures
2-PT-R084C, 23 EDG Eight-Hour Load Test, Revision 16
2-PT-R084C, 23 EDG Eight-Hour Load Test, Revision 17
2-AOP-480V-1, Loss of Normal Power to Any 480V Bus
2-AOP-RHR-1, Loss of RHR
EN-LI-102, Corrective Action Program
EN-OP-104, Operability Determination Process
2-PT-V024-DS060, Valve BFD-2-21 Inservice Test Data Sheet, Revision 10

Condition Reports (CR-IP2-)
2015-05459 2016-01256 2016-01259 2016-01260 2016-01266 2016-01355
2016-01430 2016-01500 2016-02247*

Condition Reports (CR-IP3-)
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*Denotes CR initiated as a result of the inspection

Maintenance Orders/Work Orders
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524885-6-01, 1Y Inspection of Transformer IAW 3-XFR-010-ELC, completed on May 6, 2014
52502455-01, 4Y Transformer CT Testing, completed on March 16, 2015
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Drawings
250907-35
9321-3140 Sheet 12, Boiler Feed Pump #22 Turbine Trip and Reset, Revision 34
IP2_SOD_013, Feedwater System, Revision 2

Miscellaneous
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IP3-2014-00524, Operational Decision Making Issue Process for 31 Main Transformer Gassing, Revision 1
IP3-2015-02913, Root Cause Evaluation for IP3 Turbine Trip / Reactor Trip Due to 31 Main Transformer Fault, Revision 2
System Health Report Unit 3 345 Kilovolt, Second Quarter 2014
System Health Report Unit 3 345 Kilovolt, Fourth Quarter 2015

Section 4OA3: Follow-up of Events and Notices of Enforcement Discretion

Procedures
2-PT-R084C, 23 EDG Eight-Hour Load Test, Revision 16
2-PT-R084C, 23 EDG Eight-Hour Load Test, Revision 17
2-AOP-480V-1, Loss of Normal Power to Any 480V Bus
2-AOP-RHR-1, Loss of RHR
EN-LI-102, Corrective Action Program
EN-OP-104, Operability Determination Process

Condition Reports (CR-IP2-)
2016-01256 2016-01259 2016-01260 2016-01266 2016-01355 2016-01430
2016-01500

Drawings
250907-35

Section 4OA5: Other Activities

Procedures
2-AOP-480V-1, Loss of Normal Power to Any 480V Bus
2-AOP-RHR-1, Loss of RHR
2-PT-R084C, 23 EDG Eight-Hour Load Test, Revision 16
2-PT-R084C, 23 EDG Eight-Hour Load Test, Revision 17
EN-LI-102, Corrective Action Program
EN-OP-104, Operability Determination Process

Condition Reports (CR-IP2-)
2016-00264 2016-00266 2016-00564 2016-01256 2016-01259 2016-01260
2016-01266 2016-01355 2016-01430 2016-01500

Drawings
250907-35

LIST OF ACRONYMS

10 CFR	Title 10 of the *Code of Federal Regulations*
ADAMS	Agencywide Document Access and Management System
ABFP	auxiliary boiler feedwater pump
ACE	apparent cause evaluation
AFW	auxiliary feedwater
ALARA	as low as is reasonably achievable
AOT	allowable outage time
ASME	American Society of Mechanical Engineers
CAP	corrective action program
CR	condition report
CRDM	control rod drive mechanism
ECT	eddy current testing
EDG	emergency diesel generator
FRV	feedwater regulating valve
FSB	Fuel Storage Building
FWIV	feedwater isolation valve
HRA	high radiation area
IMC	Inspection Manual Chapter
ISI	Inservice Inspection
LCO	limiting condition of operation
MBFP	main boiler feed pump
MOB	maintenance and outage building
MRP	materials reliability project
NCV	non-cited violation
NDE	non-destructive examination
NRC	Nuclear Regulatory Commission, U.S.
ORAT	outage risk assessment team
OTDT	over-temperature delta temperature
PAB	primary auxiliary building
PFP	pre-fire plan
RCS	reactor coolant system
RFO	refueling outage
RHR	residual heat removal
RO	reverse osmosis
RPS	reactor protection system
RPV	reactor pressure vessel
RWP	radiation work permit
SR	surveillance requirement
SRA	senior risk analyst
SSC	structure, system, and component
TS	technical specification
UFSAR	Updated Final Safety Analysis Report
URI	unresolved item
UT	ultrasonic examination
VT	visual examination
WHUT	waste hold-up tank
WO	work order