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

May 9, 2014

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

SUBJECT: INDIAN POINT POWER STATION – NRC INTEGRATED INSPECTION REPORT 05000247/2014002 AND 05000286/2014002

Dear Mr. Ventosa:

On March 31, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Indian Point Power Station, Units 2 and 3. The enclosed inspection report documents the inspection results, which were discussed on April 29, 2014, 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 four NRC-identified findings of NRC requirements, all of which were of very low safety significance (Green). These findings were determined to involve violations of NRC requirements. Additionally, one licensee-identified violation, which was determined to be of very low safety significance, is listed in this report. 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 the non-cited violations 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, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Indian Point Power Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding, or a finding not associated with a regulatory requirement in this report, you should provide a response with 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region I, and the NRC Resident Inspector at Indian Point Power Station.

Additionally, as we informed you in the most recent NRC integrated inspection report, cross-cutting aspects identified in the last six months of 2013 using the previous terminology were being converted in accordance with the cross-reference in Inspection Manual

Chapter 0310. Section 4OA5 of the enclosed report documents the conversion of these cross-cutting aspects which will be evaluated for cross-cutting themes and potential substantive cross-cutting issues in accordance with Inspection Manual Chapter 0305 starting with the 2014 mid-cycle assessment review. If you disagree with the cross-cutting aspect assigned, 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 Resident Inspector at Indian Point Power Station.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC'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/

Arthur L. Burritt, 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 05000247/2014002 and 05000286/2014002
w/Attachment: Supplementary Information

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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.	05000247/2014002 and 05000286/2014002
Licensee:	Entergy Nuclear Northeast (Entergy)
Facility:	Indian Point Power Station, Units 2 and 3
Location:	450 Broadway, GSB Buchanan, NY 10511-0249
Dates:	January 1, 2014 through March 31, 2014
Inspectors:	J. Stewart, Senior Resident Inspector A. Patel, Resident Inspector G. Newman, Resident Inspector T. Lamb, Acting Resident Inspector E. Burket, Emergency Preparedness Inspector S. Chaudhary, Senior Engineering Inspector J. Furia, Senior Health Physicist E. H. Gray, Senior Reactor Inspector S. Pindale, Senior Reactor Inspector
Approved By:	Arthur L. Burritt, Chief Reactor Projects Branch 2 Division of Reactor Projects

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SUMMARY

IR 05000247/2014002, 05000286/2014002; 01/01/2014 – 03/31/2014; Indian Point Power Station, Units 2 and 3; Maintenance Effectiveness; Maintenance Risk and Work Control; and Refueling and Other Outage Activities.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. Inspectors identified four non-cited violations (NCVs) of very low safety significance (Green). 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 (SDP)," dated June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Aspects Within the Cross-Cutting Areas," dated December 19, 2013. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated July 9, 2013. 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: Mitigating Systems

- Green. The inspectors identified an NCV of Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," when Indian Point Energy Center (IPEC) staff did not evaluate spalled concrete in the Unit 3 service water pit ceiling slab to the extent required by Entergy procedures. Specifically, IPEC staff referenced an operability screening for a less significant spalled condition at this location that occurred in 2012, characterized spalls that exposed load carrying rebar as "cosmetic," and did not consider the ongoing spalling. When identified by the inspectors to licensee staff, the licensee walked down the area, initiated condition report (CR)-IP3-2014-00405, and subsequently developed an operability determination and finite element analysis that determined the service water pit ceiling slab remained operable but degraded.

  The failure of licensee staff to adequately perform an operability review of concrete degradation in the Unit 3 service water pit ceiling was contrary to self-imposed procedural standards and was within the licensee ability to foresee and correct and was a performance deficiency. The performance deficiency was determined to be more than minor because, if left uncorrected, it would have the potential to become a more significant safety concern. Specifically, the failure to evaluate the spalling and exposed rebar in the operability screen resulted in IPEC staff not identifying the causes of ongoing spalling and scheduling corrective actions in a timeframe shown to be effective to maintain structural capability. The inspectors determined the finding could be evaluated using IMC 0609, Attachment 0609.04, and "Initial Characterization of Findings." The inspectors screened the finding through IMC 0609, Appendix A, "The Significance Determination Process for Findings At-Power," using Exhibit 2, "Mitigating Systems Screening Questions." The finding screened as of very low safety significance (Green) because it did not result in the loss of operability or functionality. The inspectors assigned a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, because the licensee did not thoroughly evaluate the spalled condition and in completing the operability screening process, IPEC staff did not consider

the additional spalled material that exposed rebar or causes of ongoing degradation when applying a prior operability screening for a previous less significant condition. [P.2] (Section 1R12)

- Green. The inspectors identified an NCV of 10 CFR Part 50.65(a)(4) when Entergy did not adequately re-assess and manage risk when planned maintenance was not completed as scheduled. Specifically, IPEC staff did not re-assess the risk when the scheduled activity to remove pressurizer safety valves was delayed and did not inform the control room operators in the change in plant configuration due to the delayed maintenance activity. As a result, for about one shift, the control room operators were not aware of reactor coolant system (RCS) status (intact vs. not intact) and could have been challenged in the completing recovery actions in the event of loss of residual heat removal (RHR) cooling. This issue was entered into the licensee's corrective action program as CR-IP2-2014-1986.

  Not having re-assessed risk when safety valve removal was delayed and not keeping the control room operators aware of plant status due to the delayed maintenance activity resulted in the operators not knowing RCS status (intact vs. not intact) for about 8 hours, which was contrary to Entergy's procedural requirements and was a condition reasonably within Entergy's ability to foresee and correct and was a performance deficiency. The performance deficiency was more than minor because if left uncorrected, operator response to a loss of decay heat removal could lead to an incorrect decision which could adversely affect or delay recovery actions. The inspectors evaluated the finding using IMC 0609, Attachment 0609.04, "Initial Characterization of Findings," which directed the inspectors to screen the finding through IMC 0609, Appendix G, "Shutdown Operations," using Attachment 1, Checklist 2, "PWR [pressurized-water reactor] Cold Shutdown Operation: Loops Filled and Inventory in Pressurizer." No deficiencies were identified in Checklist 2 which required a phase 2 or phase 3 quantitative assessment as the licensee maintained adequate mitigation capability. The inspectors concluded this finding had a cross-cutting aspect in the area of Human Performance, Work Management, when the licensee work process did not identify changing risk during removal of the pressurizer safety valves and manage the need for coordination between the work group and operations. Specifically, no controls were in place during the delay in pressurizer safety removal to ensure control room operators remained informed of the status of the reactor coolant system. The lack of coordination could have impacted operators' ability to respond to a loss of RHR event. [H.5] (Section 1R13)

- Green. The Inspectors identified an NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," when Entergy used a test procedure that was not appropriate to the circumstances and the operating loop of RHR was stopped during the conduct of the test. The test procedure did not assure technical specification (TS) requirements were met for an operating loop of RHR when steam generators were not available for backup decay heat removal. This issue was entered into the licensee's corrective action program as CR-IP2-2014-2709.

  The failure to accomplish testing using a procedure that ensured RCS loops were available for backup decay heat removal prior to stopping the operating RHR pump was a performance deficiency within the licensee's ability to foresee and correct and should have been prevented. The finding was more than minor because if left uncorrected, would have the potential to become a more significant safety concern, specifically, a loss of decay heat removal cooling should the RHR pump fail to restart during the test without assurance that steam generators were available to remove decay heat. The inspectors evaluated the finding using IMC 0609, Attachment 0609.04, "Initial Characterization of Findings," which directed the inspectors to screen the finding through IMC 0609, Appendix G, "Shutdown Operations," using Attachment 1, Checklist 1, "PWR Hot Shutdown Operation: Time to Core Boiling <2 Hours." No deficiencies were identified in Checklist 1 which required a phase 2 or phase 3 quantitative assessment as the licensee maintained adequate alternate mitigation capability and the finding screened to be of very low safety significance (Green). The inspectors concluded this finding had a cross-cutting aspect in the area of Human Performance, Design Margin, because the licensee did not put special attention in place to maintain safety-related equipment; specifically, when conducting testing that removed power from the running RHR loop without assurance that RCS loops remained filled and available for backup core cooling. [H.6] (Section 1R20)

Cornerstone: Barrier Integrity

- Green. The inspectors identified an NCV of 10 CFR 50, Appendix B, Criterion V, when IPEC staff failed to follow fuel handling procedures which ensure that the correct spent fuel pool configuration is used in the development of the core offload plan, ensure that a cell location is visually verified as empty prior to loading, and ensure an evaluation is performed for any situation that results in a large or unexplained change in spent fuel handling machine (SFHM) load which resulted in two fuel assembly interference events in the Unit 2 spent fuel pool. This issue was entered into the licensee's corrective action program (CAP) as CR-IP2-2014-1462.

  This finding is more than minor as it represented a challenge to the human performance attribute of the Barrier Integrity cornerstone objective to provide reasonable assurance that physical design barriers (fuel cladding) protect the public from radionuclide releases caused by accidents or events. In accordance with IMC 0609, "Significance Determination Process (SDP)," Appendix A, "The Significance Determination Process for Findings At-Power," "Barrier Integrity Screening Questions," Section D, "Spent Fuel Pool," the finding screened to be of very low safety significance (Green) when all screening questions were answered "no." The event did not result in adverse impact to the decay heat removal capabilities of the spent fuel pool; the event did not result in detectible release of radionuclides; and the event did not result in the loss of spent fuel pool water inventory. The inspectors assigned a cross-cutting aspect in the Human Performance, Avoid Complacency, when the licensee staff failed to recognize and plan for the possibility of mistakes and failed to implement appropriate error reduction tools. [H.12] (Section 1R20)

Other Findings

A violation of very low safety significance that was identified by Entergy was reviewed by the inspectors. Corrective actions taken or planned by Entergy have been entered into Entergy's corrective action program (CAP). This violation and corrective action tracking number are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 2 began the inspection period at 100 percent power and operated at full power until February 24 when the plant was shut down for a planned refueling and maintenance outage (2R21). Following refueling and maintenance activities, the reactor was started on March 18, 2014, and returned to power operation on March 19. Unit 2 achievedfull power on March 23 and remained at full power for the rest of the inspection period.

Unit 3 began the inspection period at 100 percent power. On January 6, 2014, Unit 3 tripped from full power due to a faulty feedwater valve controller that resulted in low steam generator level. The controller was repaired, and the unit restarted on January 8 and returned to full power on January 10. Unit 3 remained at full power for the remainder of the 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 cold weather on January 7, 2014. The inspectors reviewed the implementation of Indian Point adverse weather procedure OAP-48, "Seasonal Weather Preparation," before the onset of and during this adverse weather condition. The inspectors walked down the listed plant areas to ensure system availability and that there were no problems as result of the severe weather. 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 supervisors. The inspectors discussed cold weather preparedness with operators and maintained an awareness of cold weather issues throughout the cold weather periods. Documents reviewed for each section of this inspection report are listed in the Attachment.

- Unit 2 emergency diesel generator (EDG) building
- Unit 2 turbine driven fire pump building
- Unit 3 feedwater regulating valve area and adjacent auxiliary feedwater room
- Unit 3 service water room

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial System Walkdowns (71111.04Q – 5 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

Unit 2

- 22 auxiliary boiler feedwater pump using licensee procedure 2-COL-21.3, “Steam Generator Water Level,” following failure of 21 auxiliary boiler feedwater pump to start from the alternate supply 12FD3 (CR-IP2-2014-364) on January 23, 2014
- Backup spent fuel pit cooling system during core offload for refueling outage 2R21 on March 3, 2014

Unit 3

- Auxiliary feedwater train alignment on January 17, 2014
- 31 and 33 EDGs and 480V switchgear room while the 32 EDG was tagged out for maintenance on January 21, 2014
- Unit 2 appendix R diesel generator while the Unit 3 appendix R diesel generator was non-functional on March 24, 2014

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, work orders, 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 unknown deficiencies. The inspectors also reviewed whether Entergy staff had properly identified equipment issues and entered them into the 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

The inspectors performed a complete system walkdown of accessible portions of the Unit 2 safety injection 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 operability of support systems. The inspectors performed field walkdowns of accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no deficiencies. Additionally, the inspectors reviewed a sample of related CRs and work orders to ensure Entergy appropriately evaluated and resolved any deficiencies.

b. Findings

No findings were identified.

1R05 Fire Protection

.1 Resident Inspector Quarterly Walkdowns (71111.05Q – 7 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 staff 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, 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

- Auxiliary feedwater building, auxiliary feedwater pump room, and other associated elevations (pre-fire plans 259, 260, and 261 were reviewed) on January 6, 2014
- Charging pump 21, 22, and 23 cells (pre-fire plan 211 reviewed) on January 10, 2014, while an hourly fire watch was in place for spurious smoke detector alarms in 22 charging pump cell
- Fuel storage building and all associated elevations (pre-fire plan 217 was reviewed) on February 6, 2014, during multiple activities in preparation for the U2 outage
- Containment prior to return to power operations on March 15, 2014
- Compensatory actions including fire hose, foam concentrate, and fire extinguisher staging along outer fire protection loop during inner fire protection loop outage on March 31, 2014

Unit 3

- Diesel generator building, diesel generators 31, 32, and 33, and diesel generator valve room (pre-fire plan 354 was reviewed) on January 8, 2014, following planned 33 EDG two-year maintenance
- Cable spreading room, 480V switchgear room, lower and upper electrical tunnel (pre-fire plan 351, 352, 355, 356, 357 and 358 were reviewed) on January 29, 2014,

for implementation of IP-SMM-WM-101, Attachment 3, "Maintenance Rule (A)(4) Fire Risk Management Actions for Unit 3," while Temperature Element 413A, RCS wide range temperature indicator for alternate safe shutdown function was out of service (CR-IP3-2014-0274)

b. Findings

No findings were identified.

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

a. Inspection Scope

From March 3 – 12, 2014, the inspectors conducted an inspection and review of Entergy's implementation of inservice inspection (ISI) program activities for monitoring degradation of the RCS boundary, risk significant piping and components, steam generator tube integrity, and containment systems during the Indian Point Nuclear Generating Unit 2 refueling outage 2R21. 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 (NDE), reviewed documentation, and interviewed licensee personnel to verify that the NDE activities performed as part of the fourth interval, Indian Point 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.

Nondestructive Examination and Welding Activities (IP Section 02.01)

The inspectors performed direct observations of NDE activities in process and reviewed work instruction packages and records, both documentation and video of NDEs listed below:

ASME Code Required Examinations

- Observation of bare metal visual test (VT) of the reactor vessel lower head penetrations.
- Observation of bare metal VT of the reactor vessel upper head and control rod drive mechanism (CRDM) nozzle penetrations.
- Observation of the automatic computer based volumetric ultrasonic testing (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 CRDM #52.
- Observation of the visual examination and record review of the primary containment liner examination report were done per the ASME Code Section XI, IWE. The areas covered during this inspection included the accessible portions of the containment liner and containment penetrations to confirm the integrity of the containment pressure boundary.
- Review of the work package instructions and procedure for liquid penetrant surface examinations of the reactor coolant pump integral supports 23A and 23B to confirm

the inspection procedure and the examiner were qualified in accordance with the requirements of ASME Section XI.

- Observation and record review of the work package, drawings, and procedure for the manual volumetric UT of the ASME Class 1, inner radius steam generator lower head to nozzle area nozzles on steam generators 21 and 22.
- Review of the computer based UT and eddy current testing (ECT) examinations of the four reactor coolant hot leg nozzle to safe end dissimilar metal welds completed underwater from the internal root surfaces with the SQUID equipment.
- Remote observation of steam generator ECT examinations, review of the data acquisition, data evaluation, control practices, and quality assurance aspects of the eddy current examination process.

The inspectors sampled qualification certificates of the NDE examiners performing the nondestructive testing. The inspectors verified that examinations were performed in accordance with ASME Section XI procedures and the results were reviewed and evaluated by certified ASME Level III personnel.

Other Augmented or Industry Initiative Examinations

The inspectors observed Entergy's inspections in response to recommended actions in Westinghouse Nuclear Safety Advisory Letter NSAL-12-1, "Steam Generator Channel Head Degradation," which discussed industry experience on cladding defects. Specifically, the inspectors reviewed remote video coverage of the steam generator channel heads and divider plate-to-channel weld in steam generators 21, 22, and 24 and verified no appearance of degradation.

The procedure CEP-NDE-0504, Revision 2, for manual UT of small diameter piping to detect thermal fatigue per MRP-24 and MRP-146, along with the related work package, Work Order 321477, for the UT of small diameter piping of safety injection line 56 in the vicinity welds 56-3 thru 56-8 was reviewed during discussion with the UT technician performing the examinations.

Review of Previous Indications

The UT examination preparations and results of the UT of previously identified ASME Section XI NDE indications on the upper reactor head meridinal welds were observed. This examination of indications identified in 2004 verified that that no changes had occurred.

Repair/Replacement Consisting of Welding Activities

No repair/replacement activities using welding were observed during this inspection.

PWR Vessel Upper Head Penetration Inspection Activities (IP Section 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 50.55(a) and ASME Code Case N-729-1, "Alternative Examination Requirements for PWR 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 visual examination of the exterior surface of the reactor vessel upper head to verify that no boric acid leakage or wastage had been observed.

Boric Acid Corrosion Control (BACC) Inspection Activities (IP Section 02.03)

During the plant shutdown process, the NRC resident inspectors observed the boric acid leakage identification process. The ISI inspectors reviewed the BACC program, which is performed in accordance with Entergy procedures, and discussed the program requirements with the boric acid program owner. The inspector reviewed photographic inspection records of each identified boric acid leakage location and discussed the mitigation and evaluation plans. The inspector 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 (IP Section 02.04)

The inspectors directly observed a sample of the steam generator eddy current tube examinations, which consisted of full length bobbin inspection of 50 percent of all active tubes in each of the four steam generators, Rotating Probe Coil (RPC) of 50 percent in Rows 1-2 U-bends, RPC/ X probe 60 percent in the area of hot leg top-of-tubesheet, RPC/X probe of 22 percent in the area of cold leg top-of-tubesheet, and examinations of other areas of interest. The inspectors compared the scope of the ECT activities with the potential degradation mechanisms documented in the Steam Generator Degradation Assessment Report.

The inspectors verified that the steam generator eddy current tube examinations were performed in accordance with Unit 2 TS 5.5.7 and the plant Steam Generator Program. The inspectors reviewed the steam generator tube ECT results to verify that no in-situ pressure testing was required, and no primary-to-secondary leakage had occurred over the operating cycle. The inspectors verified that the steam generator tube examination screening criteria was in accordance with the Electric Power Research Institute (EPRI) Steam Generator Guidelines, Revision 7, and flaw sizing was in accordance with the EPRI guidelines.

In addition, the inspectors reviewed the sludge lancing and foreign object search and retrieval results on the secondary side of the steam generators and reviewed corrective actions to remove the foreign objects, when possible. The inspectors verified that objects not retrieved were documented, evaluated to be acceptable, or the affected tubes were stabilized and plugged.

Identification and Resolution of Problems (IP 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

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11Q – 3 samples)

Unit 2

.1 Quarterly Review of Licensed Operator Performance in the Main Control Room (1 sample)

a. Inspection Scope

The inspectors observed and reviewed reactor shutdown and cooldown activities conducted on February 24, 2014. The inspectors specifically observed the activities listed to verify that procedure use, crew communications, and coordination of activities between work groups met established expectations and standards.

- Performance of 2-E-0, Reactor Trip or Safety Injection, 2-ES-0.1, Reactor Trip Response, 2-POP-3.2, Plant Recovery from Trip, Hot Standby and transition to 2-POP-3.3, Plant Cooldown – Hot to Cold Shutdown
- Testing of main turbine stop and control valve (2-PT-SA067), OPS Logic-Actuation of Power-Operated Relief Valves (PORVs) PCV-456 & PCV-455C (2-PT-V15B), 23 EDG test (2-PT-R189C), and main steam isolation valve stroke testing (2-PT-V024E)
- Observed operator response for smoke noted coming from motor control center (MCC) 211, cubicle for breaker BFD-5-3, for 24 steam generator main feedwater isolation valve

b. Findings

No findings were identified.

.2 Quarterly Review of Licensed Operator Requalification Testing and Training

The licensee did not conduct requalification training in 2014 first quarter.

Unit 3

.3 Quarterly Review of Licensed Operator Requalification Testing and Training (1 sample)

a. Inspection Scope

The inspectors observed licensed operator simulator training on January 13, 2014, which included a loss of 480V bus, degraded reactor coolant pump seal, and a steam break in turbine building coincident with a loss of heat sink. 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 observed emergency event classification and notifications made by the shift manager and the shift technical advisor. The inspectors verified the 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 and conduct remediation activities.

b. Findings

No findings were identified.

.4 Quarterly Review of Licensed Operator Performance in the Main Control Room (1 sample)

a. Inspection Scope

The inspectors observed and reviewed portions of the reactor recovery and return to power operations conducted on January 8, 2014. The inspectors specifically observed the activities listed below to verify that procedure use, crew communications, and coordination of activities between work groups met established expectations and standards.

- Return to power operation and power escalation in accordance with licensee procedure 3-POP-1.3, "Plant Startup Zero to 45%," including block of the low power trips
- Implementation of licensee procedure 3-PT-V053E, "Mode Change Checklist Mode 3 to Mode 2"
- Infrequently performed test or evolution briefing for turbine roll, latch, and synchronize
- Response to failure of output breaker 3 to shut when placing the main generator online (CR-IP3-2014-0085)

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12Q – 3 samples)

a. Inspection Scope

The inspectors reviewed the samples listed below to assess the effectiveness of maintenance activities on structure, system, and component (SSC) performance and reliability. The inspectors reviewed system health reports, CAP documents, maintenance work orders, 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 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 staff were reasonable. As applicable, for SSCs classified as (a)(1), the inspectors assessed the adequacy of goals and corrective actions to return these SSCs to (a)(2). Additionally, the inspectors ensured that Entergy staff were identifying and addressing common cause failures that occurred within and across maintenance rule system boundaries.

Unit 2

- CR-IP2-2013-3244; Maintenance rule a(1) evaluation and actions following trip of 23 charging pump due to low oil pressure on July 11, 2013
- CR-IP2-2013-0288; Maintenance rule assessment following the loss of control power to 22 safety injection pump on January 21, 2014

Unit 3

- Structures Monitoring Report for the Indian Point Unit 3 Service Water Intake Completed in April 2011 and subsequent Corrective Action Process Documents

b. Findings

Introduction: The inspectors identified a NCV of very low safety significance (Green) of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," when the licensee did not implement procedure steps to evaluate concrete spalling that exposed rebar in the Indian Point Unit 3 service water pump pit ceiling.

Description: The Unit 3 safety-related service water motors and pumps are supported by a safety-related reinforced concrete structure that allows the deep draft pumps to be suspended in the Hudson River. A 30 inch thick concrete slab reinforced with #8 rebar in two directions with a two inch concrete cover supports the six service water motors and pumps. The bottom portion of this slab is observable, in an area called the service water pump pit, from a grating suspended above the normal Hudson River water level. Indian Point Unit 3 UFSAR Chapter 16, states, because this is a safety-related structure, that the concrete slab must be shown to maintain structural integrity under all applicable loads and load combinations.

The inspectors determined that in November 2013, the IPEC staff did not complete an adequate structural integrity verification as directed by IPEC Procedure EN-OP-104, "Operability Determination," of the service water pump structure after portions of the concrete slab were found to have fallen down from the structure on to the grating below[1]. The evaluation for this condition, documented in CR-IP3-2013-04599, inappropriately referred back to a previous 2012 evaluation of earlier spalling. The CR was closed to a work order to repair the condition, scheduled in January 2016. The inspectors found that the 2013 condition was more extensive than the 2012 condition documented and evaluated in CR-IP3-2012-2744. Specifically, inspector observation showed that the spalled area was approximately 2 feet in diameter with exposed portions of rebar, while

[1] Concrete degradation of this type, where the outer surface of the concrete separated from structure is generally referred to a spalling.

the 2012 condition was described as a spall 15 x 15 inches and less than one inch deep with no rebar exposed. The 2012 CR was closed to a work order with a statement that the spall occurred at a construction joint and justified that the condition did not affect service water pump operability because the concrete degradation "is mostly cosmetic" and "concrete slab structural integrity is not affected." The inspectors considered that the 2013 required additional evaluation because it appeared that the exposed rebar resulted in loss of bond over portions of the rebar circumference and as such could have reduced the strength of the slab. In such a situation EN-OP-104, Step 5.2.5, states when using a previous operability determination to carefully consider if a SSC is further degraded.

As a result of inspector's questions, IPEC initiated CR-IP3-2014-00405 and completed an acceptable structural finite element analysis finding that the slab remained operable but degraded or non-conforming. IPEC staff concluded the slab can perform its intended safety function, the concrete matrix itself is not subject to a degradation mechanism, and the likely cause of the spall is the existence of paths for water intrusion from a construction joint into the slab from above and freeze/thaw cycles. IPEC staff identified corrective actions to seal the slab and scheduled the work to begin in May 2015.

The inspectors further reviewed IPEC structures monitoring procedures to determine the history of this condition and whether an evaluation would be warranted under periodic maintenance rule reviews (3 year intervals). The inspectors determined the last review was completed in April 2011 and documented spalling in this area without further detail. The inspectors reviewed IPEC Procedure EN-DC-150 and identified that Attachment 9.25 provides screening and acceptance criteria for reinforced concrete structures consistent with ACI 349.3R. Specifically, the attachment lists ACI 349.3R "second tier" screening criteria that require acceptance review by the responsible engineer to determine structural integrity is maintained. These criteria include spalling 8 inches or more in any direction and spalling ¾ inches or more in depth. The inspectors noted the spalling identified under CR-IP3-2013-04599 on November 20, 2013, substantially exceeded these criteria and, if identified during periodic maintenance rule inspections, would warrant detailed review to determine whether structural integrity was maintained.

Analysis: The inspectors determined IPEC staff did not perform an adequate operability review for the spalled condition identified in CR-IP3-2013-04599, but used a previously completed evaluation for a previously identified and evaluated less significant condition. The performance deficiency was determined to be more than minor because, if left uncorrected, it would have the potential to become a more significant safety concern. Specifically, the failure to evaluate the additional spalling and exposed rebar in the operability screen resulted in IPEC staff not identifying the likely causes of ongoing spalling and scheduling corrective actions in a timeframe shown to be effective to maintain structural capability until questioned by inspectors. In addition, the finding was similar to Example 3j of NRC IMC 0612, Appendix E, "Examples of Minor Issues," in that non-conservative assumptions that the spall involved cosmetic concrete (when rebar was exposed) resulted in reasonable doubt regarding operability and warranted additional evaluation. This finding impacted the Mitigating System cornerstone considering the slab function to support service water pumps and their attendant function to support mitigating equipment in the event of a design basis seismic event.

The inspectors determined the finding could be evaluated using the Significance Determination Process," Attachment 0609.04, "Initial Characterization of Findings." Because the finding impacted the Mitigating Systems cornerstone, the inspectors screened the finding through IMC 0609 Appendix A, "The Significance Determination Process for Findings At-Power," using Exhibit 2, "Mitigating Systems Screening Questions." The finding screened as of very low safety significance (Green) because it did not result in the loss of operability or functionality. Specifically, the subsequent operability determination and supporting technical evaluation determined the SW pump slab maintained structural integrity under design basis loads with the spalled condition.

The inspectors concluded this finding had a cross-cutting aspect in the area of problem identification and resolution related to evaluation because the licensee did not thoroughly evaluate the spalled condition described in CR. Specifically, in completing the operability screening process IPEC staff did not consider the additional spalled material that exposed rebar or causes of ongoing degradation when applying a prior operability screening for a previous less significant condition. [P.2]

Enforcement: 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires, in part, that activities affecting quality shall be prescribed and accomplished by procedures appropriate to the circumstances. Step 5.2.2 of EN-LI-104 stated "Evaluate the information in the Condition Report." Step 5.6.5 stated "If a previous Operability Evaluation is being used to develop the current Operability Evaluation, carefully consider if the SSC is further degrading." Contrary to the above, as of November 20, 2013, IPEC staff did not follow Procedure EN-LI-104 when evaluating the operability of the IP3 service water pump pit ceiling slab spalled condition. Specifically, IPEC staff did not evaluate the current spalled condition as described in CR-IP3-2013-04599 and did not consider further spalling that occurred when applying a previous operability screening for the condition. In response to inspector questions, IPEC staff implemented corrective actions to develop an adequate operability determination based on a finite element analysis that showed the SW pump slab remained operable but degraded or non-conforming and scheduled repair activities planned for May 2015. Because this violation was of very low safety significance and was entered into IPEC's corrective action program as CR-IP3-2014-00405, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy (NCV 05000286/2014002-01, **Inadequate Operability Evaluation of Spalled Concrete in the Service Water Pit Structure)**

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 9 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 personnel 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 personnel 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

- January 14, 2014: Risk assessment and risk management actions taken after failure of 22 charging pump to maintain pressurizer level on program (CR-IP2-2014-0185) while 13.8 kV cross-tie 33332 was out of service for repair of breaker BT 4-5.
- January 22, 2014: Elevated risk associated with the planned maintenance and testing of the 23 charging pump. The inspectors verified Entergy's contingency postings in accordance with Entergy's procedure EN-OP-119, "Protected Equipment Postings," and procedure EN-WM-104, "On Line Risk Assessment," as part of the inspection.
- February 3, 2014: Elevated risk associated with planned safety injection train B logic testing. The inspectors verified Entergy's contingency postings in accordance with Entergy's procedure EN-OP-119, "Protected Equipment Postings," and procedure EN-WM-104, "On Line Risk Assessment," as part of the inspection.
- February 26, 2014: Risk planning and management during conduct of 2-PT-R014, "Automatic Safety Injection System Electrical Load and Blackout Test."
- February 28, 2014: Risk management during RCS draining to 68' to support vessel head removal. The inspectors verified appropriate contingency actions for coping with a loss of RHR cooling.

Unit 3

- January 13, 2014: Elevated risk associated with testing of the B reactor protection system train while cross-tie breaker BT4-5 and 35 service water pumps remained out of service for planned maintenance. Elevated trip risk due to unavailability of 345 kV output breaker 3 was also verified to be included in the licensee's determination.
- January 21, 2014: Elevated risk associated with the RCS Loop 1 temperature calibration, the 32 EDG out of service due to planned maintenance, and severe winter weather warning. The inspectors verified Entergy's contingency postings in accordance with Entergy's procedure EN-OP-119, "Protected Equipment Postings," and procedure EN-WM-104, "On Line Risk Assessment," as part of the inspection.
- February 6, 2014: Overspeed test of 31 EDG (CR-IP2-2013-0359) and Entergy's procedure OAP-008, "Severe Weather," risk assessment, and risk management actions.
- February 20, 2014: Risk assessment and risk management actions taken for de-energizing MCC 37 as a result of breaker cubicle wires heating for cubicle (MCC 37 5FH) which feeds the Fuel Storage Building (FSB) and fan house welding receptacles (CR-IP3-2014-00474).

b. Findings

Introduction: The inspectors identified a Green NCV of 10 CFR Part 50.65(a)(4) when Entergy did not adequately re-assess and manage risk when planned maintenance was not completed as scheduled. Specifically, the licensee did not re-assess the risk when the scheduled activity to remove pressurizer safety valves and vent the RCS was delayed and did not inform the control room operators in the change in plant configuration due to the delayed maintenance activity. As a result, for approximately one shift, the control room operators were not aware of RCS status (intact vs. not intact) and would have been challenged in the completing recovery actions in the event of loss of RHR cooling.

Description: On February 26, 2014, with Unit 2 in the third day of a planned refuel outage (time to boil in the RCS was less than 46 minutes), the licensee established conditions for outage testing, vessel head lift, and planned reactor coolant pump maintenance. At the time, 21 RHR pump was running to provide decay heat removal; the pressurizer was drained to about 50 percent; and the RCS was de-pressurized through blocked open PORV and open block valves. Planned work to establish a vent path to containment by removing pressurizer safety valves was ongoing.

The work to remove the pressurizer safety valves had been planned for the early morning hours of February 26, prior to the start of day shift. Due to delays from the previous shift maintenance personnel did not log onto the associated pressurizer safety valve removal tagout until 08:16. This indicated to the control room that already delayed activity was in now progress. The risk assessment for February 26 day shift assumed the safety valves were removed and the assessment was not redone when the work was delayed. Licensee procedure IP-SMM-OU-104, “Shutdown Risk Assessment,” step 6.3.2, requires the shift manager to perform a risk assessment anytime that changes to equipment status occur that have a potential for changing the current risk assessment. With the plant depressurized and vented, gas dissolved in the RCS could accumulate in the top of the steam generator tubes which would inhibit natural circulation cooling if RHR were lost. With the unbolting and removal of the first pressurizer safety, recovery of RCS loops, which would be necessary provide pressure control needed for decay heat removal by natural circulation, would be prevented. With the safety valves in place, restoration of pressure control could be established from the control room by closing the PORV block valves.

During an interview, the control room operators told the inspectors that they did not know the status of pressurizer safety removal during dayshift, however since the work was authorized in the morning, the operators assumed that the first pressurizer safety was removed. If RHR cooling was interrupted, operators would enter procedure, 2-AOP-RHR-1, “Loss of RHR,” where step 4.11 asks if RCS is intact. Not knowing the status of RCS (intact versus not intact) would have complicated the recovery actions depending how the operators answer the step 4.11 question. The inspectors could not determine which recovery path would have been taken by the operators.

The licensee did not ensure controls were in place to allow the control room operators to monitor the progress of pressurizer safety removal and no requirements were included in the maintenance instructions for pressurizer safety removal to notify the control room when the first safety valve was unbolted or removed from the system. Licensee procedure EN-OP-115, “Conduct of Operations,” requires all operators to maintain a constant awareness of plant status. The licensee did not monitor the on-going activity to remove safety valves and failed to comply with procedure IP-SMM-OU-104, “Shutdown

Risk Assessment," step 6.3.2, which requires that, "As a normal routine the SM (shift manager) or designee shall monitor equipment status and plant conditions for change. The SM shall perform a risk assessment anytime that changes to equipment status or plant conditions have a potential for changing the current risk assessment." The licensee documented the inspector's concern in the CAP as CR-IP2-2014-1986.

Analysis: The inspectors determined that the licensee did not adequately re-assess and manage the risk as required by 10 CFR 50.65 (a)(4), when the activity to remove pressurizer safety valves was delayed. The licensee did not have a method in place to keep control room operators aware of plant status as the work was in progress. This resulted in the operators not knowing RCS status (intact vs. not intact) for about 8 hours which was contrary to the licensee's procedural requirements and was a condition reasonably within the licensee's ability to foresee and correct and was a performance deficiency. The performance deficiency was determined to be more than minor because, if left uncorrected, it would have the potential to become a more significant safety concern. Specifically, operator response to a loss of decay heat removal could lead to an incorrect decision which would affect or delay recovery actions. The finding impacted the Mitigating Systems cornerstone objective to support decay heat removal capability in the event of loss of RHR.

The inspectors evaluated the finding using IMC 0609, Attachment 0609.04, "Initial Characterization of Findings," which directed the inspectors to screen the finding through IMC 0609, Appendix G, "Shutdown Operations," using Attachment 1, Checklist 2, "PWR Cold Shutdown Operation: Loops Filled and Inventory in Pressurizer." No deficiencies were identified in Checklist 2 which required a phase 2 or phase 3 quantitative assessment to determine if the licensee maintained adequate mitigation capability. Therefore, the finding screened as Green significance.

The inspectors determined that this finding had a cross-cutting aspect in the area of Human Performance, Work Management, when the licensee work process did not identify changing risk during removal of the pressurizer safety valves and manage the need for coordination between the work group and operations. Specifically, no controls were in place during pressurizer safety removal to ensure control room operators maintained awareness of the status of the reactor coolant system. The lack of coordination could have impacted operators' ability to respond to a loss of RHR event [H.5].

Enforcement: 10 CFR Part 50.65(a)(4) states, in part, "before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities." The licensee implements this requirement in part, using IP-SMM-OU-104, "Shutdown Risk Assessment," which requires, in step 6.3.2 that the shift manager perform a risk assessment anytime that changes to equipment status occur that have a potential for changing the current risk assessment. Contrary to the above, on February 26, the licensee failed to assess risk and perform a risk assessment when a maintenance activity which affected equipment status (safety valve removal) was delayed. In planning for the work, the licensee did not have a method in place to assure control room operators remained aware of RCS status and as a result, control room operators were not aware of the status of the RCS (intact or not) which could have delayed recovery had a loss of RHR cooling occurred. When identified to the licensee by the inspectors, CR-IP2-2014-1986 was written. Because this violation was of very low safety significance and was entered into IPEC's CAP as CR-IP2-2014-1986, this violation is being treated as a NCV, consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000247/2014002-02, Incomplete Risk Assessment While Pressurizer Safety Valves Were Being Removed)**

1R15 Operability Determinations and Functionality Assessments (71111.15 – 7 samples)

a. Inspection Scope

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

Unit 2

- CR-IP2-2014-00171 - Nuclear Power Range Channel N-41 delta flux read higher than normal on January 13, 2014; the inspectors verified inputs of the nuclear channels to the reactor protection system were not affected by the conditions.
- High RCS leakage identified on January 16, 2014. The inspectors verified containment parameters within normal ranges and no trend on volume control tank level. The leakage was associated with tag out of the 22 charging pump for repairs.
- CR-IP2-2014-00288 - Control room operators identified a loss of control power for 22 safety injection pump on bus 2A, where the green indicating light was not lit and the W2 light was not lit on January 21, 2014. The inspectors review included post maintenance testing of start and shutdown of the pump per 2-SOP-10.1 and verified the control power was restored to 22 safety injection pump from bus 2A.
- CR-IP2-2014-00364 - During the performance of 2-PT-Q017A, 21 Auxiliary Feed Pump 440V Breaker, 12FD3-1B, tripped free when attempting to start the pump on January 23, 2014. The inspectors review included the post-maintenance testing and corrective action to enhance preventive maintenance procedure.
- CR-IP2-2014-0776 - Operability of spent fuel pool following testing that revealed boraflex degradation exceeded assumptions in some panels on March 31, 2014. Compensatory measures reviewed included a higher than required boron concentration in the fuel pool, daily sampling, and twice per shift visual checks by operators to verify no dilution of the pool inventory.

Unit 3

- CR-IP3-2014-0074 - Discrepancies identified during 3-PT-V52, Nuclear Power Low Range Channels Functional Test, on January 7, 2014, the inspectors verified inputs of the nuclear channels to the reactor protection system were not affected by the conditions.
- CR-IP3-2014-00242 - High delta P was observed during the quarterly 34 service water pump operational test on January 22, 2014. The inspectors reviewed data from several tests, corrective actions, and the applicable engineering report to verify that the results were within the pump limits.

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. 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. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18 – 2 samples)

.1 Temporary Modification

a. Inspection Scope

The inspectors reviewed the temporary modifications listed below to determine whether the modifications affected the safety functions of systems that are important to safety. The inspectors reviewed 10 CFR 50.59 documentation and post-modification testing results and conducted field walkdowns of the modifications to verify that the temporary modifications did not degrade the design bases, licensing bases, and performance capability of the affected systems.

- Engineering Change 43656; Temporary jumper installed to provide valve indication for Unit 3 RHR suction valve AC-MOV-743 and other valves while the open limit contacts are non-functional (CR-IP3-2013-2165 and 2088).

b. Findings

No findings were identified.

.2 Permanent Modification

a. Inspection Scope

The inspectors evaluated a modification to the Unit 2 instrument air system implemented by Engineering Change 29868, Atmospheric Dump Valve Nitrogen Control Room Capability Upgrade. The inspectors verified that the design bases, licensing bases, and performance capability of the affected systems were not degraded by the modification which was installed to provide backup atmospheric dump valve operating capability from the control room on a loss of instrument air. The inspectors reviewed modification documents associated with the upgrade and design change, including installation drawings and alignment procedures. The inspectors also walked down the modification and reviewed the operating procedure to ensure the procedure could be reasonably performed.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19 – 8 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 procedure had been properly reviewed and approved. The inspectors also witnessed the test or reviewed test data to verify that the test results adequately demonstrated restoration of the affected safety functions.

Unit 2

- Functional test of 24 Service Water Pump Alternate Safe Shutdown Supply Verification following planned preventive maintenance using Entergy's Test 2-PT-017E on January 29, 2014
- Full flow test of 21 auxiliary feed pump following replacement of Foxboro controller per Engineering Change 22909 (CR-IP2-2014-0943) on February 21, 2014
- Leak rate test using 2-PT-R026A-DS004, 22 Reactor Coolant Pump Seal Injection Valves 250B, 4926, following valve 4926 stem failure and actuator overhaul on March 11, 2014
- Actuation logic test and trip actuating device operational test following replacement of 480V bus 6A undervoltage relay 27/1-6A on March 14, 2014
- One hour load test using licensee procedure PFM-119, "Static Inverter Testing," on 24 static inverter following installation of a permanent modification to the current transformer wiring under work order 00315307 on March 17, 2014

Unit 3

- Functional test of 33 EDG following planned maintenance activities using Entergy's Test 3-PT-M079C on January 6, 2014
- Functional test of 35 Service Water Pump Reference Test following pump replacement using Entergy's Test 3-PT-V059E on January 13, 2014
- Functional test of 34 service water pump strainer using section 4.3 of Entergy procedure 3-PT-Q092D on January 23, 2014, following one-year preventive maintenance

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20 – 1 sample)

a. Inspection Scope

The inspectors reviewed the station's work schedule and outage risk plan for the Unit 2 maintenance and refueling outage 2R21, which was conducted on February 24 through March 19, 2014. The inspectors reviewed Entergy's development and implementation of outage plans and schedules to verify that risk, industry experience, previous site-specific problems, and defense-in-depth were considered. During the outage, the inspectors observed activities and monitored controls associated with the following outage activities:

- Configuration management, including maintenance of defense-in-depth, commensurate with the outage plan for the key safety functions and compliance with the applicable TSs when taking equipment out of service
- Implementation of clearance activities and confirmation that tags were properly hung and that equipment was appropriately configured to safely support the associated work or testing
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication and instrument error accounting
- Status and configuration of electrical systems and switchyard activities to ensure that TSs were met
- Monitoring of decay heat removal operations
- Impact of outage work on the ability of the operators to operate the spent fuel pool cooling system
- Reactor water inventory controls, including flow paths, configurations, alternative means for inventory additions, and controls to prevent inventory loss
- Activities that could affect reactivity
- Refueling activities, including core offload and reload fuel handling
- Fatigue management
- Tracking of startup prerequisites, walkdown of the containment to verify that debris had not been left which could block the emergency core cooling system suction strainers, and startup and ascension to full power operation
- Identification and resolution of problems related to refueling outage activities

b. Findings

.1 Unit 2 Spent Fuel Pool Fuel Assembly Interference Events

Introduction: The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion V, "Procedures," associated with the licensee's failure to follow fuel handling procedures which resulted in two fuel assembly interference events on March 3, 2014.

Description: On March 2, 2014, Indian Point Unit 2 core offload to the spent fuel pool began in support of the 2R21 Refueling Outage. Offload to the spent fuel pool is performed in accordance with licensee procedure 0-NF-203, "Internal Transfer of Fuel Assemblies and Inserts." A fuel transfer control form is generated prior to the outage using the spent fuel pool configuration management program, SHUFFLEWORKS. Licensee reactor engineers prepare and verify the correct version of SHUFFLEWORKS to ensure that the condition of the spent fuel pool is known prior to developing the core offload plan. The resulting core offload plan prevents fuel assembly interference events.

On December 11, 2013, during development of the core offload plan for 2R21, the licensee did not use the current SHUFFLEWORKS revision of the spent fuel pool inventory. This resulted in selection of an occupied spent fuel pool cell location as the destination for an offloaded assembly.

While offloading the core to the spent fuel pool, a crew of two fuel handlers, an operator and a spotter, are positioned above a fuel assembly on the spent fuel handling machine (SFHM). Licensee procedure EN-FAP-OU-108, "Fuel Handling Process," requires that the SFHM operator and spotter verify that the SFHM at the correct location and that the cell is empty prior to lowering a fuel assembly into the location.

On March 3, 2014, at 9:30 pm, the fuel handling crew at the spent fuel pool had received a fuel assembly to be placed in the spent fuel pool. Due to cloudy conditions in the spent fuel pool water, the fuel handling crew had difficulty visually verifying the conditions of the individual spent fuel locations. In this case the fuel handling crew noted that the target cell appeared to be dark with a blue glow. The blue glow was believed to be coming from an adjacent cell already occupied with a fuel assembly based upon conditions observed in other locations. This destination cell was identified as empty; but due to a latent error in the offload plan, the destination location was occupied.

Upon lowering the assembly at a slow speed into the cell, the SFHM experienced an unexpected underload condition which immediately stopped the lowering of the assembly (fuel interference event 1). Licensee procedure 2-SOP-17.12, "Spent Fuel Handling Machine and Spent Fuel Pit Operations," precaution step 2.18 states that, "The operator when moving fuel or inserts should monitor the load cell indication, and when any tool is being raised and lowered. In the event that a large or unexplained change in load occurs, the operator SHALL immediately stop the equipment and evaluate the situation."

Without investigating the source of the underload condition, the crew lifted the assembly to clear the underload condition, and then lowered it again resulting in a second underload condition (fuel interference event 2). Upon raising the assembly the crew was able to confirm that a fuel assembly already occupied the location. The offloaded assembly was moved to a different analyzed empty location; and, licensee management was informed. The inspectors provided information gathered from interviews not known to licensee management concerning the event including the fuel handlers' attempt to lower the assembly a second time as well as refuel floor supervisor's request to perform a stand down prior to continuing offload which was denied. The event was entered into the CAP as CR-IP2-2014-1462. The licensee performed evaluations and video examinations of the fuel assemblies and found no damage to the fuel assemblies. These activities were verified by the inspectors.

Analysis: The inspectors determined that failure to follow fuel handling procedures which ensure that the correct spent fuel pool configuration is used in the development of the core offload plan, ensure that a cell location is visually verified as empty prior to loading, and ensure that an evaluation is performed for any situation that results in a large or unexplained change in SFHM load was a performance deficiency that was reasonably within the licensee's ability to foresee and correct. This finding was more than minor in accordance with IMC 0612, "Power Reactor Inspection Reports," Appendix B, "Issue Screening," dated September 7, 2012, as it represented a challenge to the human performance attribute of the Barrier Integrity cornerstone objective to provide reasonable assurance that physical design barriers (fuel cladding) protect the public from radionuclide releases caused by accidents or events. Reasonable assurance was lost based upon the unknown condition of the fuel assemblies subsequent to the two interference events and the licensee's need to perform evaluation and visual examination to verify the condition of the physical design barrier.

In accordance with IMC 0609, Attachment 0609.04, "Initial Characterization of Findings," and IMC 0609, Appendix A, Exhibit 3, "Barrier Integrity Screening Questions", Section D, "Spent Fuel Pool," the finding screened to be of very low safety significance (Green), when all screening questions were answered "no." There was no impact to the decay heat removal capabilities of the spent fuel pool; the event did not result in detectible release of radionuclides; the event did not result in any loss of water inventory; and the event did not affect the spent fuel pool reactivity.

The inspectors assigned a cross-cutting aspect in Human Performance, Avoid Complacency, in that, the licensee staff failed to recognize and plan for the possibility of mistakes and did not implement appropriate error reduction tools. Specifically, Reactor Engineering did not recognize the use of an out-of-date spent fuel pool configuration when developing the core offload plan. Further, after performing a number of fuel moves in the spent fuel pool in support of core offload, the SFHM operator and spotter did not verify that the destination rack location was empty prior to lowering a fuel assembly and failed to evaluate the cause of the unplanned underload condition prior to attempting to lower the bundle for a second time [H.12].

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Procedures," states, in part, "activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings." Entergy implements this requirement through fuel handling procedures 2-NF-203, which requires the use of the current spent fuel pool configuration when developing any fuel transfer forms, EN-FAP-OU-108, which requires verification that a fuel assembly cell is empty prior to attempting to load a fuel assembly, and 2-SOP-17.12, which requires the evaluation of any situation that results in a large or unexplained change in SFHM load. Contrary to the above, licensee staff on December 11, 2013, did not use of the current spent fuel pool configuration when developing the fuel transfer form associated with core offload. This violation existed until March 3, 2014, when contrary to the above, licensee staff did not verify that a fuel assembly cell was empty prior to attempting to load a fuel assembly into it and did not evaluate a large and unexplained change in SFHM load and underload condition prior to attempting to load the assembly into the cell a second time. Because this issue is of very low safety significance (Green) and the licensee has entered this issue into their CAP asCR-IP2-2014-1462, this finding is being treated as an NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. (**NCV 05000247/2014002-03, Spent Fuel Pool Fuel Assembly Interference Events**)

.2 Unit 2 Blackout Test with Reactor Coolant Loops Not Available for Residual Heat Removal

Introduction: The Inspectors identified a Green, NCV of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," when Entergy used a test procedure that was not appropriate to the circumstances when the operating loop of RHR was stopped during the conduct of the test. The test procedure did not assure TS requirements were met for an operating loop of RHR when steam generators were not available for backup decay heat removal. As part of the 2014 outage plan (2R21) and in previous outages, the licensee planned testing which stopped the running RHR pump by securing power to its associated 480 volt safety bus without procedure provisions to assure reactor coolant loops were available for backup decay heat removal as required.

Description: On February 26, 2014, with Unit 2 in the third day of a planned refueling outage, the licensee performed 2-PT-R014, "Automatic Safety Injection System Electrical Load and Blackout Test." Prior to start of the test, 21 RHR pump was running providing decay heat removal. The RCS was drained to 50 percent pressurizer level and depressurized through open pressurizer PORVs. The outage plan included removing pressurizer safety valves over a 12-hour period that started when the pressurizer draining was complete at approximately 3:00 a.m. on the same day. At 11:20 a.m. for Train A and again at 2:17 p.m. for Train B, the licensee performed the blackout test, each time removing offsite power to the 480V buses which stopped the operating 21 RHR pump. The pump automatically re-started as the buses recovered on emergency power. TS 3.4.8 requires a minimum of one running RHR pump when RCS loops are not available for backup decay heat removal. RCS loops are not available for decay heat removal when the plant is depressurized with pressurizer safety valves removed as adequate subcooling (more than 10 degrees) to support natural circulation cooling cannot be maintained.

The inspectors reviewed the 2012 outage (2R20) to determine if the 2014 plan to stop the running RHR pump with loops not available for backup decay heat removal was an isolated occurrence. The inspectors noted that during 2R20 the blackout test was performed on March 7, 2012, at 9:36 a.m. for Train A and 1:32 p.m. for Train B. The operator log entry on the morning of March 7, 2012, stated that the RCS was not intact and steam generators were not available for core cooling. In 2014, the RCS was drained to 50 % in the pressurizer and work to remove pressurizer safety valves was authorized and in progress when the test was conducted. The inspectors concluded that the licensee in 2014 as well as 2012 planned and performed a test procedure that did not assure compliance with the TS requirement to maintain one RHR pump running for decay heat removal when RCS loops were not filled and available for natural circulation cooling. When identified to the licensee by the inspectors, the licensee documented the procedure inadequacy in CR-IP2-2014-2709 and began an investigation. The licensee investigated the inspector's concerns and informed the inspectors that due to further work delays, the pressurizer safety valves remained in-place and RCS loops were available for backup decay heat removal when the testing was actually performed.

Analysis: The failure to accomplish testing using a procedure that ensured RCS loops were available for backup decay heat removal prior to stopping the operating RHR pump while in Mode 5 was a performance deficiency within the licensee's ability to foresee and correct and should have been prevented. The finding was more than minor because if left uncorrected, would have the potential to become a more significant safety concern, specifically, a loss of decay heat removal cooling should the RHR pump fail to restart during the test without assurance that steam generators were available to remove decay heat. The finding impacted the Mitigating Systems cornerstone attribute of Configuration Control – Shutdown Equipment Lineup which has an objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences.

The inspectors evaluated the finding using IMC 0609, Attachment 0609.04, "Initial Characterization of Findings," which directed the inspectors to screen the finding through IMC 0609, Appendix G, "Shutdown Operations," using Attachment 1, Checklist 1, "PWR Hot Shutdown Operation: Time to Core Boiling <2 Hours." No deficiencies were identified in Checklist 1 which required a phase 2 or phase 3 quantitative assessment as the licensee maintained adequate alternate mitigation capability and the finding screened as Green.

The inspectors concluded this finding had a cross-cutting aspect in the area of Human Performance, Design Margin, because the licensee did not put special attention in place to maintain safety-related equipment; specifically, when conducting testing that removed power from the running RHR loop without assurance that RCS loops remained filled and available for backup core cooling [H.6].

Enforcement: 10 CFR 50, Appendix B, Criterion V, "Procedures," states, in part, "activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings." Entergy implements this requirement, in part, with test procedure 2-PT-R014, "Automatic Safety Injection System Electrical Load and Blackout Test," which directs testing operations that simultaneously removes offsite power from all safety buses momentarily stopping loads, including the running RHR pump. TS 3.4.8 requires a minimum of one RHR pump operating when RCS loops are not available for backup decay heat removal. Contrary to the above, on April 26, 2014, Entergy conducted testing using procedure 2-PT-R014 that was not appropriate to the circumstance when prerequisites to conduct the test did not assure that RCS loops were available for backup decay heat removal prior to stopping the running RHR pump. As a result, Entergy planned to conduct the test while establishing conditions that rendered the RCS loops unavailable for backup decay heat removal. This issue was entered into the licensee's corrective action program as CR-IP2-2014-2709. Because this issue is of very low safety significance (Green) and the licensee has entered this issue into their CAP as CR-IP2-2014-2709, this finding is being treated as an NCV consistent with Section 2.3.2.a of the NRC Enforcement Policy. **(NCV 05000247/2014002-04, Inappropriate Procedural Controls When Stopping RHR Without Assurance that RCS Loops Were Filled and Available for Natural Circulation Cooling)**

1R22 Surveillance Testing (71111.22 – 8 samples)

a. Inspection Scope

The inspectors observed performance of surveillance tests and/or reviewed test data of selected risk-significant systems to assess whether test results satisfied TSs, the UFSAR, and Entergy 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, including inservice testing (IST) and containment isolation valve testing (CIV):

Unit 2

- 2-PT-Q029C, 23 Safety Injection Pump, on January 6, 2014
- 2-PT-R022A, Steam Driven Auxiliary Feed Pump Full Flow, on February 23, 2014 (IST)
- 2-PT-R026A-DS020, Reactor Coolant Drain Tank to Gas Analyzer Valves 1788, 1789, on February 27, 2014 (CIV)
- 2-PT-R027C-DS002, Containment Pressure Relief Valves PCV-1191 and PCV-1192, on March 15, 2014 (CIV)

Unit 3

- 3-PT-M079A, 31 EDG Functional Test, on January 9, 2014
- 3-PT-Q93C, Reactor Coolant Flow Functional Test – Channel III, on January 16, 2014
- 3-PT-M14B, Safety Injection System Logic Functional Train B, on January 22, 2014
- 3-PT-Q120C, 33 Auxiliary Feedwater Pump, on January 30, 2014

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04 – 1 sample)

a. Inspection Scope

Entergy implemented various changes to the Indian Point Energy Center Emergency Action Levels (EALs), Emergency Plan, and Implementing Procedures. Entergy had determined that, in accordance with 10 CFR 50.54(q)(3), any change made to the EALs, Emergency Plan, and its lower-tier implementing procedures, had not resulted in any reduction in effectiveness of the plan, and that the revised plan continued to meet the standards in 50.47(b) and the requirements of 10 CFR 50 Appendix E.

The inspectors performed an in-office review of all EAL and Emergency Plan changes submitted by Entergy as required by 10 CFR 50.54(q)(5), including the changes to lower-tier emergency plan implementing procedures, to evaluate for any potential reductions in effectiveness of the Emergency Plan. This review by the inspectors was not documented in an NRC Safety Evaluation Report and does not constitute formal NRC approval of the changes. Therefore, these changes remain subject to future NRC inspection in their entirety. The requirements in 10 CFR 50.54(q) were used as reference criteria.

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)

During the week of March 10–14, 2014, the inspectors reviewed licensee performance in assessing the radiological hazards in the workplace associated with licensed activities and the implementation of appropriate radiation monitoring and exposure control measures for both individual and collective exposures. The inspectors verified that the licensee is properly identifying and reporting performance indicators (PIs) for the Occupational Radiation Safety Cornerstone and identifying those performance deficiencies that were reportable as a PI. The inspectors used the requirements in 10 CFR Part 20 and guidance in Regulatory Guide 8.38, “Control of Access to High and Very High Radiation Areas for Nuclear Plants,” TSs, and the licensee’s procedures required by TSs as criteria for determining compliance.

a. Inspection Scope

Radiological Hazard Assessment

The inspectors verified that appropriate pre-work surveys were performed which were appropriate to identify and quantify the radiological hazard and to establish adequate protective measures. The inspectors evaluated the radiological survey program to determine if hazards were properly identified, including the following:

- Identification of hot particles
- The presence of alpha emitters
- The potential for airborne radioactive materials, including the potential presence of transuranics and/or other hard-to-detect radioactive materials
- The hazards associated with work activities that could suddenly and severely increase radiological conditions
- Severe radiation field dose gradients that can result in non-uniform exposures of the body

The inspectors selected air sample survey records and verified that samples were collected and counted in accordance with licensee procedures. The inspectors observed work in potential airborne areas, and verified that air samples were representative of the breathing air zone. The inspectors verified that the licensee has a program for monitoring levels of loose surface contamination in areas of the plant with the potential for the contamination to become airborne.

Instructions to Workers

The inspectors reviewed radiation work permits (RWPs) used to access high radiation areas (HRAs) and identify what work control instructions or control barriers had been specified. The inspectors verified that allowable stay times or permissible dose for radiologically significant work under each RWP was clearly identified. The inspectors verified that electronic personal dosimeter (EPD) alarm set points were in conformance with survey indications and plant policy.

Radiological Hazards Control and Work Coverage

During tours of the facility and review of ongoing work the inspectors evaluated ambient radiological conditions. The inspectors verified that existing conditions were consistent with posted surveys, RWPs, and worker briefings.

During job performance observations, the inspectors verified the adequacy of radiological controls, such as required surveys, radiation protection job coverage, and contamination controls. The inspectors evaluated the licensee's means of using EPDs in high noise areas as HRA monitoring devices.

The inspectors verified that radiation monitoring devices were placed on the individual's body placed in the location of highest expected dose or that the licensee was properly employing an NRC-approved method of determining external dose.

For high-radiation work areas with significant dose rate gradients (a factor of 5 or more), the inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel. The inspectors verified that licensee controls were adequate.

The inspectors reviewed RWPs for work within airborne radioactivity areas and evaluated the air monitoring and personnel controls. For these selected airborne radioactive material areas, the inspectors verified barrier integrity and temporary high-efficiency particulate air ventilation system operation.

The inspectors examined the licensee's physical and programmatic controls for highly activated or contaminated materials stored within spent fuel and other storage pools. The inspectors verified that appropriate controls were in place to preclude inadvertent removal of these materials from the pool.

The inspectors conducted selective inspection of posting and physical controls for HRAs and very high radiation areas to verify conformance with the Occupational PI.

Radiation Worker Performance

During job performance observations, the inspectors observed radiation worker performance with respect to radiation protection work requirements. The inspectors determined that workers were aware of the significant radiological conditions in their workplace and the RWP controls/limits in place and that their performance reflected the level of radiological hazards present.

The inspectors reviewed radiological problem reports since the last inspection that found the cause of the event to be human performance errors. The inspectors determined that there was no observable pattern traceable to a similar cause. The inspectors determined that this perspective matched the corrective action approach taken by the licensee to resolve the reported problems. The inspectors discussed with the radiation protection manager (RPM) any problems with the corrective actions planned or taken.

Radiation Protection Technician Proficiency

During job performance observations, the inspectors observed the performance of the radiation protection technician with respect to radiation protection work requirements. The inspectors determined that technicians were aware of the radiological conditions in their workplace and the RWP controls/limits and that their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

The inspectors reviewed radiological problem reports since the last inspection that found the cause of the event to be radiation protection technician error. The inspectors determined that there was no observable pattern traceable to a similar cause. The inspectors determined that this perspective matched the corrective action approach taken by the licensee to resolve the reported problems.

Miscellaneous

Since the last inspection of this area, the licensee assigned a new individual to serve as the RPM. This position has specific qualifications set forth in TS 5.3.1. When the inspectors asked to see the licensee's records verifying that the new RPM met the TS criteria, no record could be found. The licensee wrote CR-IP3-2014-00611 to document this discrepancy, and later provided the inspectors with a copy of a completed (March 10, 2014) Attachment 9.1 of procedure EN-HR-137, Revision 4, "Complying with the Standards for Selecting Nuclear Power Plant Personnel," which documented the licensee's evaluation of the qualifications for the newly designated RPM.

b. Findings

No findings were identified.

2RS2 Occupational As Low As Is Reasonably Achievable Planning and Controls (71124.02)

During the week of March 10–14, 2014, the inspectors assessed performance with respect to maintaining individual and collective radiation exposures as low as is reasonably achievable (ALARA). The inspectors used the requirements in 10 CFR Part 20, Regulatory Guide 8.8, "Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Plants will be As Low As Reasonably Achievable," Regulatory Guide 8.10, "Operating Philosophy for Maintaining Occupational Radiation Exposure As Low as Reasonably Achievable," TSs, and the licensee's procedures required by TSs as criteria for determining compliance.

a. Inspection Scope

Radiological Work Planning

The inspector obtained from the licensee a list of work activities ranked by estimated exposure that were in progress during the Unit 2 refueling outage (2R21) and selected work activities of the highest exposure significance.

The inspector reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements. The inspector determined that the licensee had reasonably grouped the radiological work into work activities, based on historical precedence and industry norms.

The inspector verified that the licensee's planning identified appropriate dose mitigation features, considered alternate mitigation features, and defined reasonable dose goals. The inspector verified that the licensee's ALARA assessment had taken into account decreased worker efficiency from use of respiratory protective devices. The inspector determined that the licensee's work planning considered the use of remote technologies as a means to reduce dose and the use of dose reduction insights from industry operating experience and plant-specific lessons learned. The inspector verified the integration of ALARA requirements into work procedure and RWP documents.

Verification of Dose Estimates and Exposure Tracking Systems

The inspector verified that for the selected work activities that the licensee had established measures to track, trend, and reduce occupational doses for ongoing work activities. The inspector verified that dose thresholds were established to prompt additional reviews and/or additional ALARA planning and controls.

Radiation Worker Performance

The inspector observed radiation worker and radiation protection technician performance during work activities being performed in radiation areas, airborne radioactivity areas, or HRAs. The inspector concentrated on work activities that present the greatest radiological risk to workers. The inspector determined that workers demonstrate the ALARA philosophy in practice and that there were no procedure compliance issues. Also, the inspector observed radiation worker performance to determine whether the training and skill level was sufficient with respect to the radiological hazards and the work involved.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151 – 4 samples)

a. Inspection Scope

The inspectors reviewed Entergy's submittal for the RCS specific activity and RCS leak rate PIs for both Unit 2 and Unit 3 for the period of January 1, 2013, through December 31, 2013.

- Unit 2 RCS Specific Activity (BI01)
- Unit 2 RCS Leak Rate (BI02)
- Unit 3 RCS Specific Activity (BI01)
- Unit 3 RCS Leak Rate (BI02)

To determine the accuracy of the PI 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 PI. Additionally, the inspectors observed surveillance activities that determined the RCS identified leakage rate, and chemistry personnel taking and analyzing an RCS sample.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 – 1 sample)

.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 screening meetings.

b. Findings

No findings were identified.

.2 Annual Sample: Turbine-Driven Auxiliary Feedwater Pump Test Failure (1 sample)

a. Inspection Scope

The inspectors performed an in-depth review of Entergy's evaluations and corrective actions associated with condition report CR-IP3-2013-00887, which documented an in-service test (IST) failure of the No. 32 turbine-driven auxiliary feedwater (AFW) pump. Specifically, during a full flow test, the pump achieved about 400 gpm compared to the associated acceptance criterion of 740 gpm. The turbine speed and pump discharge pressure parameters also did not meet acceptance criteria.

The inspectors assessed Entergy's problem identification threshold, problem analysis, extent of condition reviews, compensatory actions, and the prioritization and timeliness of their corrective actions to evaluate 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 corrective action program and 10 CFR Part 50, Appendix B. The inspectors performed a field walkdown and interviewed engineering personnel to assess the adequacy of the planned and completed corrective actions. The inspectors also observed a portion of a quarterly IST of the No. 32 AFW pump on April 2, 2014. Finally, the inspectors reviewed the associated Licensee Event Report (LER 05000286/2013-003-00) as described in Section 4OA3.2 of this report.

b. Findings and Observations

No findings were identified.

Entergy discovered the condition during the No. 32 AFW pump full flow IST on March 3, 2013. Their subsequent investigation identified that the steam admission valve failed to stroke properly, which was the result of poor maintenance during Spring 2011 refueling outage. Specifically, sealant was identified on the turbine thrust bearing housing external surface, which prevented the housing from moving axially to open the steam admission valve. Sealant is used on the nearby mating surfaces of the upper and lower governor housing to allow the mating surfaces to be joined together, but was not to be applied to other surfaces/components. Entergy initiated condition report CR-IP3-2013-00887, performed corrective maintenance, conducted an extent-of-condition review for the IP Unit 2 turbine-driven AFW pump, and completed a detailed technical analysis and operability assessment of the impact of the reduced flow from the No. 32 AFW pump.

Entergy's technical review (past operability assessment) determined that, although the No. 32 AFW was inoperable per Technical Specifications, as identified by the full-flow IST, the pump remained functional for analyzed transients and accidents. Entergy's determination was based on actual flow data from the March 3, 2013, test, as well as existing design and licensing bases assumptions. The inspectors reviewed Entergy's analyses and found them to be reasonable and consistent with existing design and licensing bases.

The inspectors also reviewed Entergy's corrective actions, including their extent-of-condition review. Overall, Entergy's actions were appropriate and addressed the apparent and contributing causes for the event. One exception was related to a procedure change to the IST quarterly test which incorporated an additional verification to stroke and measure movement of the steam admission valve. The inspectors determined the associated procedure change was inappropriately implemented as an editorial change, contrary to guidance specified in procedure IP-SMM-AD-102, "IPEC Implementing Procedure Preparation, Review, and Approval," Revision 7; and that the change should have had a Process Applicability Determination review performed in accordance with EN-LI-100, "Process Applicability Determination." The inspectors determined that this issue was minor because the procedure change was not substantial and did not change the procedure's intent. Entergy entered this issue into their CAP as CR-IP3- 2014-00727.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153 – 1 sample)

.1 Plant Events

a. Inspection Scope

For the plant event 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 Parts 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 3

- On January 6, 2014, Unit 3 tripped from full power due to a faulty feedwater valve controller that resulted in low steam generator level. The controller was repaired, and the unit restarted on January 8 and returned to full power on January 10, 2014.

b. Findings

No findings were identified.

.2 (Closed) LER 05000286/2013-003-00, Technical Specification Prohibited Condition Due to Turbine-Driven Auxiliary Feedwater Pump Failure to Meet Test Acceptance Criteria (1 sample)

On March 3, 2013, the turbine-driven AFW pump failed to meet the IST Program full flow test acceptance criteria during its full flow test. A subsequent investigation identified that the steam admission valve failed to stroke properly, which was the result of poor maintenance during the Spring 2011 refueling outage. Specifically, sealant was identified on the turbine thrust bearing housing external surface, which prevented the housing from moving axially to open the steam admission valve. Sealant is used on the nearby mating surfaces of the upper and lower governor housing to allow the mating surfaces to be joined together. Entergy initiated condition report CR-IP3-2013-00887, performed corrective maintenance, conducted an extent-of-condition review for the IP Unit 2 turbine-driven AFW pump, and completed a detailed technical analysis and operability assessment of the impact of the reduced flow from the No. 32 AFW pump. The LER and associated apparent cause evaluation were reviewed for accuracy, the appropriateness of corrective actions, violations of requirements, and generic issues. The enforcement aspects of this issue are discussed in Section 4OA7 of this report. The inspectors did not identify any new issues during review of the LER. This LER is closed.

4OA5 Other Activities

.1 Inspection Procedure 92709 Licensee Strike Contingency Plans

a. Inspection Scope

Entergy developed a Staffing Contingency Plan to ensure a sufficient number of qualified personnel were available to continue operations in the event of a job disruption associated with the January 18, expiration of the Entergy contract with the Utility Workers Union of America (UWUA), Local 1-2. Using the guidance contained in NRC Inspection Procedure 92709, “Licensee Strike Contingency Plans,” the inspectors reviewed Entergy’s plans to address the potential job action at the site. The inspection included an evaluation of the Staffing Contingency Plan content and the actions needed to implement the plan; a review to determine whether the number of qualified personnel needed for the proper operation of the facility would be available; a review to determine if reactor operations could be maintained, as required; and a review to determine if the plan complied with TS requirements and other NRC requirements. On January 17, NRC inspectors started continuous site coverage pending a contract agreement. During this time, the inspectors conducted walkdowns of systems important to safety and monitored the licensee’s activities. On January 18, at approximately 3:45 a.m., Entergy and UWUA, Local 1-2, announced a tentative agreement and extended the contract. The tentative agreement was subsequently ratified.

b. Findings

No findings were identified.

.2 Cross-Reference of 2013 Cross-Cutting Aspects to New Cross-Cutting Aspects

The table below provides a cross-reference from the 2013 and earlier findings and associated cross-cutting aspects to the new cross-cutting aspects resulting from the common language initiative. These aspects and any others identified since January 2014 will be evaluated for cross-cutting themes and potential substantive cross-cutting issues in accordance with IMC 0305 starting with the 2014 mid-cycle assessment review.

Finding	Old Cross-Cutting Aspect	New Cross-Cutting Aspect
05000247/2013403-01 05000286/2013403-01	H.4(b)	H.8
05000247/2013403-02 05000286/2013403-02	H.1(b)	H.14
05000247/2013403-03 05000286/2013403-03	P.1(a)	P.1
05000247/2013404-02 05000286/2013404-02	H.2(b)	H.9
05000247/2013404-03 05000286/2013404-03	H.4(c)	H.2
05000247/2013404-04 05000286/2013404-04	P.1(a)	P.1

4OA6 Meetings, Including Exit

On April 29, 2014, the inspectors presented the inspection results to Mr. John Dinelli, General Manager Plant Operations, and other members of the Entergy staff. The inspectors verified that no proprietary information was retained by the inspectors or documented in this report.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by Entergy and is a violation of NRC requirements which meets the criteria of the NRC Enforcement Policy for being dispositioned as an NCV.

- On March 3, 2013, Energy discovered that the No. 32 turbine-driven AFW pump failed to meet the IST Program full flow test acceptance criteria during its full flow test. A subsequent investigation identified that the steam admission valve failed to stroke properly, which was the result of poor maintenance during the Spring 2011 refueling outage. Specifically, sealant was identified on the turbine thrust bearing housing external surface, which prevented the housing from moving axially to open the steam admission valve. Technical Specification 3.7.5 Limiting Condition for Operation requires all three AFW trains to be operable in Modes 1, 2, and 3. Contrary to this requirement, the No. 32 turbine-driven AFW pump was inoperable for a time period that exceeded the Technical Specification allowed outage time of 72 hours (exact time was indeterminate since it was the result of maintenance performed during the Spring 2011 refueling outage). This finding was determined to be of very low safety significance (Green) because the finding did not represent a loss of the entire AFW system or function. Specifically, further detailed evaluation concluded that although the turbine-driven pump was not operable as per technical specifications, the pump remained functional for analyzed transients and accidents. This issue was documented in Entergy's CAP as condition report IP3-2013-00887.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Entergy Personnel

J. Ventosa, Site Vice President
N. Azevedo, Code Programs Supervisor
S. Bianco, Operations Fire Marshall
R. Burroni, Engineering Director
T. Chan, Mechanical Systems Supervisor
D. Dewey, Assistant Operations Manager
J. Dinelli, General Manager Plant Operations
R. Dolanksy, ISI Program Manager
R. Drake, Civil Design Engineering Supervisor
J. Ferrick, Production Manager
D. Gagnon, Security Manager
F. Inzirillo, Training Manager
F. Kich, Performance Improvement Manager
J. Kirkpatrick, Director, Regulatory and Performance Improvement
D. Mayer, Unit 1 Director
T. McCaffrey, Design Engineering Manager
B. McCarthy, Operations Manager
M. Miele, Emergency Planning Manager
F. Mitchell, Radiation Protection Manager
J. Spagnulo, Maintenance Manager
M. Tesoriero, System Engineering Manager
M. Troy, Quality Assurance Manager
R. Walpole, Regulatory Assurance Manager
T. Chan, Engineering Supervisor
R. Gioggia, System Engineer

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Opened/Closed

05000286/2014-002-01	NCV	Inadequate Operability Evaluation of Spalled Concrete in the Service Water Pit Structure (Section 1R12)
05000247/2014-002-02	NCV	Incomplete Risk Assessment While Pressurizer Safety Valves Were Being Removed (Section 1R13)
05000247/2014-002-03	NCV	Spent Fuel Pool Fuel Assembly Interference Events (Section 1R20)
05000247/2014-002-04	NCV	Inappropriate Procedural Controls When Stopping RHR Without Assurance that RCS Loops Were Filled and Available for Natural Circulation Cooling (Section 1R20)

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
Indian Point Unit 3, Updated Final Safety Analysis Report
Indian Point Unit 3, Individual Plant Examination
Indian Point Unit 3, Individual Plant Examination of External Events
Indian Point Unit 3, Technical Specifications and Bases
Indian Point Unit 3, Technical Requirements Manual
Indian Point Unit 3, Control Room Narrative Logs
Indian Point Unit 3, Plan of the Day

Section 1R01: Adverse Weather Protection

Condition Reports (CR-IP2-)
2013-0398 (reviewed ACE for frozen piping and verified seasonal weather preparations procedure revised)

Section 1R04: Equipment Alignment

Procedures
3-COL-EL-005, Diesel Generators

2-COL-21.3, Steam Generator Water Level, Revision 32
2-COL-10.0, Locked Safeguards Valves, Revision 42
2-COL-10.1.1, Safety Injection System

Drawings
Dwg. No. 9321-F-2735, Flow Diagram Safety Injection System
Dwg. No. A235296-71, Flow Diagram Safety Injection System

Miscellaneous
IPEC, Unit 2, SI – SIS, System Health Report for Period Q4-2013

Section 1R05: Fire Protection

Condition Reports (CR-IP2-)
2014-02445

Miscellaneous
EN-DC-128, Attachment 9.1 Appendix R Fire Protection Program Review for IP1/IP2 Fire Header Outage for FP-1, 2, 3, 4, 6, 7 Replacement

Section 1R08: Inservice Inspection Activities

Procedures
2-PT-R204, Visual Examination of Reactor Vessel Bottom Mounted Instrumentation Penetrations for Leakage, Revision 3
SEP-BAC-IPC-001, Boric Acid Corrosion Control Program, Revision 0
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LIST OF ACRONYMS

10 CFR	Title 10 of the *Code of Federal Regulations*
ALARA	as low as is reasonably achievable
ASME	American Society of Mechanical Engineers
BACC	boric acid corrosion control
CAP	corrective action program
CFR	*Code of Federal Regulations*
CIV	containment isolation valve
CR	condition report
CRDM	control rod drive mechanism
EAL	emergency action level
ECT	eddy current examination
EDG	emergency diesel generator
Entergy	Entergy Nuclear Northeast
EPD	electronic personal dosimeter
EPRI	Electric Power Research Institute
HRA	high radiation area
IMC	Inspection Manual Chapter
IP3	Indian Point Unit 3
IPEC	Indian Point Energy Center
ISI	inservice inspection
IST	inservice test
MCC	motor control center
NCV	non-cited violation
NDE	nondestructive examination
NRC	Nuclear Regulatory Commission
PI	performance indicator
PORV	power-operated relief valve
PWR	pressurized-water reactor
RCS	reactor coolant system
RHR	residual heat removal
RPC	rotating probe coil
RPM	radiation protection manager
RWP	radiation work permit
SFHM	spent fuel handling machine
SM	Shift Manager
SSC	structure, system, and component
TS	technical specification
UFSAR	Updated Final Safety Analysis Report
UT	ultrasonic testing
UWUA	Utility Workers Union of America
VT	visual test