August 4, 2003

Mr. Fred R. Dacimo
Site Vice President
Entergy Nuclear Northeast
Indian Point Energy Center
295 Broadway, Suite 1
Post Office Box 249
Buchanan, NY 10511-0308

SUBJECT: INDIAN POINT 3 NUCLEAR POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000286/2003006

Dear Mr. Dacimo

On June 28, 2003, the US Nuclear Regulatory Commission (NRC) completed an inspection at the Indian Point 3 Nuclear Power Plant. The enclosed report presents the results of that inspection. The results were discussed on July 16, 2003, with Mr. Chris Schwarz 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. Within these areas, the inspection consisted of a selected examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of the inspection, four findings of very low safety significance (Green) were identified. None of these findings represented an immediate safety concern, but two of the findings were determined to involve violations of NRC requirements. However, because of their very low safety significance, and because they are entered into your corrective action program, the NRC is treating these two findings as Non-Cited Violations (NCVs) consistent with Section VI.A. of the NRC Enforcement Policy. If you contest any NCV 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, D.C. 20555-0001; and the NRC Resident Inspector at Indian Point 3.

Since the terrorist attacks on September 11, 2001, NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance controls over access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order. Phase 1 of TI 2515/148 was completed at all commercial power nuclear power plants during calender year '02 and the remaining inspection activities for Indian Point 3 were completed in January 2003. The NRC will continue to monitor overall safeguards and security controls at Indian Point 3.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room **or** from the Publicly Available Records (PARS) component of the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Peter W. Eselgroth, Chief
Projects Branch 2
Division of Reactor Projects

Docket No. 50-286
License No. DPR-64

Enclosure: Inspection Report No. 50-286/03-06

Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-286
License No.	DPR-64
Report No.	05000286/2003006
Licensee:	Entergy Nuclear Northeast
Facility:	Indian Point 3 Nuclear Power Plant
Location:	Buchanan, NY
Dates:	March 30 - June 28, 2003
Inspectors:	P. Drysdale, Senior Resident Inspector M. Cox, Resident Inspector P. Habighorst, Senior Resident Inspector L. James, Resident Inspector W. Cook, Senior Project Engineer T. Jackson, Project Engineer M. Modes, Senior Reactor Inspector S. Barr, Operations Engineer J. McFadden, Radiation Specialist G. Smith, Senior Physical Security Inspector D. Silk, Senior Emergency Preparedness Inspector A. Dimitriadis, Physical Security Inspector
Approved by:	Peter W. Eselgroth, Chief Projects Branch 2 Division of Reactor Projects

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SUMMARY OF FINDINGS

Summary of Findings (cont'd)

IR 05000286/2003-006, on 03/30/2003 - 06/28/03, Entergy Nuclear Northeast, Indian Point 3 Nuclear Power Plant. Operability Evaluations; Refueling and Outage Activities; Event Follow-up.

The report covered a 3-month period of inspection by resident inspectors, regional project engineers, a reactor inspector, an operations engineer, radiation specialist, security inspectors, and a health physics specialist. Four Green findings were identified, of which, two were non-cited violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," (SDP). The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 3, dated July 2000.

A. <u>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Initiating Events

- <u>Green</u>. On April 29, 2003, a self-revealing Green finding was identified involving poor maintenance practices and inadequate work controls during main turbine bearing inspections which contributed to the improper reinstallation of the No. 2 bearing casing and an oil leak which caused a fire. Operators initiated a manual turbine and reactor trip and declared an Unusual Event based upon the duration of the fire.

  This finding was greater than minor since it was associated with the protection against external factors (fire) and the human performance attributes that affect the Initiating Events cornerstone objective; and since maintenance work control inadequacies resulted in a perturbation in plant stability by causing a reactor trip. The finding is of very low safety significance (Green) as determined using the SDP Phase 1 worksheet. Specifically, the event did not increase the likelihood of a primary or secondary system loss of coolant accident initiator, did not contribute to a loss of mitigation equipment functions, and did not increase the likelihood of an internal/external flood. (Section 4OA3)

Cornerstone: Mitigating Systems

- <u>Green</u>. The inspectors identified a violation of 10CFR50, Appendix B, Criterion V, involving inadequate configuration controls that led to the unintended operation of the No. 31 safety injection (SI) pump with zero flow for greater than the maximum time limit established by the pump manufacturer.

  This finding is greater than minor because it is associated with the human performance and configuration control attributes that affect the Mitigating Systems cornerstone objective; and since the operators did not properly implement configuration controls required by the procedures that govern SI pump operation. The finding is of low safety significance since pump damage did not occur as a result of this human performance error. This issue is being treated as a non-cited violation. (Section 1R15)

- Green. A self-revealing finding occurred involving a configuration control error which resulted in the inadvertent loss of primary spent fuel pool cooling for approximately 15 minutes.

  This finding is greater than minor since it is associated with the configuration control and human performance attributes that affect the Mitigating Systems cornerstone objective. This finding is of very low safety significance since the loss of normal cooling was of short duration, there was no appreciable increase in spent fuel pool temperature, and the back-up spent fuel pool cooling system was in service at the time. (Section 1R20)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a violation of 10 CFR 50, Appendix B, Criterion V, involving an inadequate procedure and poor maintenance practices which contributed to the ejection of a barrier plug in a steam generator nozzle. The consequence of these inadequacies was the draining of approximately 5000 gallons of reactor coolant system inventory to the containment sump.

  This finding is greater than minor since it is associated with the procedure quality attribute of the Barrier Integrity cornerstone objective. The failure to perform an adequate verification that the bowl drain plug was properly installed was of a very low safety significance since RCS inventory control was maintained and there was no rise in RCS temperature. Accordingly, this issue is treated as a non-cited violation. (Section 1R20)

B. Licensee Identified Violations

None

Report Details

SUMMARY OF PLANT STATUS

At the beginning of the inspection period, the reactor was in cold shutdown (Mode 4) and outage activities were underway at the beginning of the plant's 12^{th} refueling (3R12). A plant shutdown was initiated on March 28, 2003, and cold shutdown was achieved on March 29. The plant remained shutdown in a refueling outage until April 20 when plant heat-up commenced. Criticality was achieved on April 22, and the plant returned online on April 23.

During the plant power ascension on April 29, 2003, the main turbine and reactor were manually tripped from 59% power after operators detected a fire in the insulation surrounding the high pressure turbine. The licensee declared a Notice of Unusual Event (NUE) in accordance with plant procedures when the duration of the fire exceeded 15 minutes. The fire was extinguished after 51 minutes. The plant remained in hot shutdown while an investigation was performed into the root cause of the fire, the extent of fire damage was determined, and repairs to the damaged insulation were completed. The plant was restarted on April 29, returned online on April 30, and achieved full power on May 1.

On June 22, 2003, the reactor automatically tripped from 100% power following the failure of a 345KV output breaker in the Buchanan switchyard. Automatic protective actions within the switchyard caused all output circuits to open and the subsequent load rejection caused the turbine and reactor to automatically trip. Shortly after the trip, the licensee depressurized and cooled down the reactor in order to repair a core exit thermocouple Conoseal joint above the reactor head, to repair several leaks in the electro-hydraulic control oil system of the main turbine-generator, and to repair piping to a feedwater heater drain pump cooler. Following these repairs, the plant was restarted on June 26, synchronized to the grid on June 27, and returned to full power on June 28.

1. REACTOR SAFETY
(Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness)

1R04 Equipment Alignment (Quarterly)

a. Inspection Scope (71111.04Q)

The inspectors performed a system walkdown during a period of system train unavailability in order to verify that the alignment of the available train was proper to support the required safety functions and to assure there were no equipment discrepancies that could potentially impair the functional capability of the available train.

- During March 31 - April 1, 2003, the inspectors performed a partial system alignment check of the 32 and 33 emergency diesel generators (EDGs) to verify operability while the 31 EDG was out of service for planned maintenance. The inspectors used check-off list COL-EL-5, "Diesel Generators," and System Operating Procedure SOP-EL-001, "Diesel Generator Operation" to verify the proper equipment alignment and to identify any discrepancies that could impact the function of the available EDGs or that could potentially increase plant risk.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (Semi-Annual)

a. Inspection Scope (71111.04S)

Between May 20 and June 21, 2003, the inspectors performed a comprehensive walkdown of the safety injection (SI) system including all system piping, pumps, valves, and instruments outside containment. The inspection was performed to verify that the system alignment was proper to support the availability of the SI safety functions, and to assure that the licensee had identified equipment discrepancies that could potentially impair the functional capability of the system. The inspectors used check-off list COL-SI-1, "Safety Injection System," and flow diagrams 9234-F-27203 and 9234-F-27353 to verify proper system alignment for full power operations, and to assure consistency between the check-off list and the flow diagrams.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (Quarterly)

a. Inspection Scope (71111.05Q)

.1 The inspectors conducted fire protection tours in the fire zones listed below to ensure that the licensee was controlling transient combustibles in accordance with fire protection procedure FP-9 "Control of Combustibles"; to ensure that ignition sources were controlled in accordance with FP-8, "Controlling of Ignition Sources"; to ensure that fire protection equipment was provided as specified in the Pre-Fire Plans (PFPs); and to assess the general material condition of fire protection barriers and fire suppression equipment. These areas were selected for inspection based on their relative fire initiation risk and the safe shutdown equipment located in the areas.

- Fire Zones 39A and 41A: On April 3, 2003, the inspectors performed a walk-through of the feedwater heater drain pump area on the 15-foot elevation of the turbine building, using PFP-41, "Heater Drain Pumps - Turbine Building." The inspectors observed a number of 55-gallon waste oil storage drums in the north-west corner of fire zone 41A and various other outage-related equipment and components near the roll-up door. The inspectors verified through the fire protection supervisor that the 55-gallon drums were empty and that other materials were within combustible loading limits.

- Fire Zones 16, 17, 18, and 42A: On April 3, the inspectors performed an inspection of the turbine lube oil storage and reservoir area on the 15-foot elevation of the turbine building, using PFP-42, “Turbine Lube Oil Storage/Reservoir - Turbine Building.”

- Fire Zones 43A, 44A, 46A, 47A, and 48A: On April 3, the inspectors performed a walk-through of the 36-foot elevation of the turbine building, using PFP-43, “General Floor Plan - Turbine Building.” The inspectors discussed fire protection precautions with a number of plant workers involved with a variety of outage-related work activities including major equipment overhauls, piping repairs/replacements, and non-destructive examinations. The inspectors reviewed the numbers and locations of additional portable fire suppression equipment (fire extinguishers) that was staged in areas where hot work was being conducted.

- Fire Zones 2 & 2A: On May 16, the inspectors toured the area around the containment spray pumps on the 41-foot level of the Primary Auxiliary Building (PAB) using PFP-9, “Containment Spray Pumps - Primary Auxiliary Building.”

- Fire Zone 22: On May 16, the inspectors performed a walk-through of the plant intake structure using PFP-69, “Circulating & Service Water Pump Bldg.”

- Fire Zone 52A: On May 20, the inspectors performed a walk-through of the 32-foot 6-inch elevation of the Auxiliary Boiler Feedwater Building using PFP-48, “Chemical Additive Room - Auxiliary Feedwater Building.” The inspectors examined chemical drums in the area of chemical addition mixing tanks for proper storage and labeling.

- Fire Zone 131: On May 23, the inspectors performed a walk-down of the Appendix “R” diesel generator enclosure and the adjacent exterior areas, using PFP-72, “Service Water Back-Up Pumps/Appendix “R” Diesel.”

- Fire Zones 64A, 65A, 66A, & 67A: On June 6, the inspectors performed an inspection of the main transformer yard using PFP-62, “Main Transformer Yard.” The inspectors observed the physical condition of the deluge system for the 31 and 32 Main Transformers, and the Unit and Station Auxiliary Transformers. The inspectors also evaluated the transformer oil cooling systems for leakage and observed the general area for combustible material loading.

1R05 Fire Protection (Annual)

a. Inspection Scope (71111.05A)

On June 19, 2003, the inspectors observed an unannounced fire brigade drill. The drill was conducted in accordance with the licensee's pre-planned drill scenario, and simulated an oil fire at the 31 EDG. The drill was a routine training exercise for current fire brigade members. The inspectors evaluated the readiness of the fire brigade to suppress and contain the fire, and evaluated the following aspects of the drill:

- The fire brigade properly donned protective clothing/turnout gear.
- Self-contained breathing apparatus (SCBA) equipment was properly worn and used.
- Fire hose lines were capable of reaching all necessary fire hazard locations, were laid out without flow restrictions, and were simulated as charged with water.
- Brigade members entered the fire area in a controlled manner.
- Sufficient fire fighting equipment was brought to the scene by the fire brigade.
- Effective smoke removal operations were simulated.
- The fire fighting pre-plan strategies were utilized.
- The licensee's pre-planned drill scenario was followed.
- The drill objectives and acceptance criteria are met.

The inspectors also observed the post-drill critique and evaluated it for thoroughness and degree of critical self-assessment.

b. Findings

No significant findings were identified (Quarterly & Annual).

1R08 In-service Inspection

.1 Steam Generator Eddy Current Testing

a. Inspection Scope (71111.08)

The inspectors evaluated the licensee's steam generator (SG) degradation assessment program, and compared it with the NRC accepted guidance contained in the Electric Power Research Institute, "Pressurized Water Reactor Steam Generator Examination Guidelines," Rev 5. To evaluate how the SG assessment program was implemented, the inspectors witnessed the remote visual survey of the 31 SG tube sheet to verify that the eddy current data collection station was correctly positioned and that the robotic probe placement was correct. The inspectors also witnessed the calibration verification of an eddy current probe used in the 31 SG and verified that the eddy current "C" scan representations corresponded with the correct location on the calibration standard. The inspectors witnessed the eddy current data being extracted from the 31 SG (taken from tubes located at row 23, column 41 and row 15, column 73), and also witnessed the independent qualified data analyst review of indications at row 15, column 73 of the 31

SG. The inspectors reviewed the bobbin coil data taken from row 1, columns 4, 40, and 42 with two resolution analysts to determine how probe noise (caused by slight tube ovality in the bend) was being accommodated in the evaluation process. The inspectors discussed with an independent resolution analyst the tentative characterization as a lancing scar of a signal in the 33 SG, located at row 1, column 66. The inspectors reviewed the eddy current data acquired, during the current outage for the scar indication, the data from the same location taken the last time the tube was inspected in 1999, and the data originally taken when the SG was installed (8.9 effective full power years ago) to determine if the indication was present prior to lancing of the generator. The inspectors discussed with the resolution analyst the planned evaluation of the indication with a rotating pancake coil.

The inspectors discussed with the licensee's technical lead the loose parts monitoring and removal program for the SGs. The inspectors also reviewed with responsible vendor personnel the visual survey of the secondary side of the SGs. The recorded remote visual survey of columns 28 and 29 of the 31 SG was reviewed to determine if the possible loose part (identified by eddy current) was found by the remote visual inspection.

The inspectors reviewed the results of the nondestructive testing of various components chosen from a list that was limited by the licensee's application for a risk informed in-service inspection sample set to determine the licensee's conformance with American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, and NRC guidance. The inspectors discussed the results of the inspections with licensee staff and vendor personnel. The inspectors discussed with a cognizant technical lead the radiograph of a socket weld chosen through the risk-informed inservice inspection program, and the resolution of a possible thinned section of the tubing that was revealed by the radiography.

b. Findings

No findings of significance were identified.

.2 Pressure Vessel Head Ultrasonic Inspection

a. Inspection Scope (Temporary Instruction 2515/150)

In April 2003, Entergy conducted volumetric (ultrasonic) inspections of the IP3 reactor pressure vessel (RPV) head in accordance with the requirements of Section XI of the ASME Pressure Vessel Code. These inspections were conducted as part of the licensee's routine in-service inspection program. The licensee discovered an indication in the head-to-flange weld inspection region. The licensee characterized the indication consistent with ASME Code criteria as being parallel to the plane of the head-to-flange weld, surface breaking on the head inside diameter, with a length of 1.0 inch in the circumferential or azimuthal direction, and a depth into the base metal of the head of 0.4 inches. The licensee used this characterization of the indication in their fracture mechanics-based flaw evaluation. The licensee evaluated the flaw in accordance with the requirements of ASME Code, Section XI, IWB-3600. The licensee's evaluation was performed by Structural Integrity Associates, which concluded that:

> "the observed indication meets...for acceptability the requirements of the flaw evaluation procedures of ASME Section XI, IWB-3600, because there is no active mechanism for flaw propagation, no flaw growth is expected, and the indication will remain acceptable for the life of the component."

The NRC staff reviewed the analysis performed for the licensee as contained in Report HLG-03-006/SIR-03-047, "Disposition of Indication Found in the Indian Point 3 Closure Head," Revision 1, dated April 14, 2003, by Structural Integrity Associates, Inc. The staff's review was performed to verify that the evaluation procedures and acceptance criteria used were in accordance with the requirements of Section XI of the ASME Code. Further, the staff evaluated the assumptions made with regard to the applied loadings on the flaw indication and the material properties of the head material to assure that they were either accurate or conservative. The staff verified that the licensee's evaluation supported the determination that the observed flaw indication can be left in service and that, in accordance with ASME Code Section XI, IWB-3132.4(b) and IWB-2420(b), the licensee planned to re-examine the area containing the flaw indication during the next three inspection periods, consistent with IWB-2410.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (Quarterly)

a. Inspection Scope (71111.11Q)

On June 2, 2003, the inspectors observed simulator training for licensed operators of Operations Team "3E" (2003 requalification cycle 032). The inspectors reviewed the simulator scenario documented in Lesson Plan No. LRQ-SES-001, "Loss of Condenser Vacuum / Faulted SG," to determine if the scenario contained: 1) clear event descriptions with realistic initial conditions; 2) clear start and end points; 3) clear descriptions of visible plant symptoms for the crew to recognize; and 4) clear expectations of operator actions in response to abnormal conditions.

During the simulator exercise, the inspectors evaluated the team's performance for: 1) clarity and formality of communications; 2) correct use and implementation of emergency operating procedures (EOPs) and off-normal operating procedures (ONOPs); 3) operators' ability to properly interpret and verify alarms; and 4) operators' ability to take timely actions in a safe direction based on transient conditions. In addition, the inspectors evaluated the control room supervisor's ability to exercise effective oversight and control of the crew's actions during the exercise. The inspectors verified that the feedback from the instructors was thorough, that they identified specific areas for improvement, and that they reinforced management expectations regarding crew competencies in the areas of procedure use, communications, and peer-checking. The inspectors also evaluated the adequacy of the licensee's post-scenario critique.

b. Findings

No findings of significance were identified. One minor issue involving problems with simulator phone service was documented in condition report CR-IP3-2003-3420.

1R12 Maintenance Effectiveness (Quarterly)

.1 Corrective Maintenance Effectiveness

a. Inspection Scope (71111.12Q)

The inspectors reviewed the following maintenance activities and recent systems and components performance issues to assess the effectiveness of the licensee's Maintenance Rule program. Using 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," and Regulatory Guide 1.1.60, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," the inspectors verified that the licensee was implementing their Maintenance Rule program in accordance with NRC regulations and guidelines, properly classifying equipment failures, and using the appropriate performance criteria for Maintenance Rule systems in 10 CFR 50.65 (a)(2) status.

The inspectors also reviewed work orders (WOs), and associated post-maintenance test (PMT) activities, to assess whether: 1) the effect of maintenance work in the plant had been adequately addressed by control room personnel; 2) work planning was adequate for the maintenance performed; 3) the acceptance criteria were clear and adequately demonstrated operational readiness consistent with design and licensing documents; and 4) the equipment was effectively returned to service. The following maintenance activities and associated documents were observed and evaluated:

- WOs IP3-03-02492 and IP3-03-14220: Repair of 34 Steam Generator Atmospheric Dump Valve (ADV) following difficult operation from the control room, and subsequent stroke time test failure (reference CR-IP3-2003-1591 and CR-IP3-2003-01709).

  During the plant cooldown on March 29, 2003, the inspectors noted that operators had difficulty operating the 34 ADV (MS-PCV-1137) from inside the control room while releasing main steam through the ADVs. Operators had to operate this valve manually until Instrumentation and Control (I&C) technicians performed troubleshooting, which concluded that the valve had been sticking. During a subsequent inservice test, the valve failed to stroke within its required time, and the valve's indicated position at 20% open did not agree with the demand signal (35%) from the valve's pressure controller (PC-449). The licensee performed diagnostic testing on the valve and found degradation of the valve frame near the stem guide bushing, wear on the operator diaphram case, rubbing of the yoke on the frame, and mispositioned bracket bolts on two limit switches. The licensee performed maintenance on the valve to correct these conditions, and conducted post-maintenance testing to restore the valve to operability.

- WO IP3-03-16303: Replacement of Power Range Nuclear Instrument (PRNI) Detector N-44

  During preparations for low power physics testing on April 22, 2003, the licensee noted a significant difference between the upper and lower detector currents for N-44. This was documented in CR-IP3-2003-02643 and evaluated by systems engineering, which concluded that the detectors would function properly at higher power. While increasing reactor power between 22% and 25% on April 24, N-44 indication began to oscillate, which caused relay chatter and eventually a blown control power fuse. A vendor specializing in PRNI cable testing was contracted to troubleshoot the system. A high resistance connection was identified in the detector that induced noise onto the cable's center conductor and caused the oscillations. This required replacement of the detector.

  The inspectors reviewed the work order (IP3-03-16303) that governed the replacement, and Westinghouse procedure (NSBU-EIS-00-027), "NIS Power Range Channel N-44 Replacement Procedure." The inspectors verified the documentation was sufficient in scope to perform the replacement work. PRNI replacements were normally performed while the plant is shut down; however, the licensee elected to perform the work with the reactor critical at less than 2% power. The inspectors reviewed the licensee's radiation dose estimate and surveys for the work and discussed these with the licensee to ensure they met the principles of ALARA. The inspectors reviewed the post-work test and documentation to ensure that the testing was comprehensive, based on the work performed, and that the instrument was properly returned to service.

  The inspectors also evaluated how the PRNI system was being tracked in the licensee's Maintenance Rule Program. The inspectors verified Technical Service Procedure TSP-057, "Maintenance Rule Instruction for Maintenance Preventable Functional Failure Determination," was being properly used to evaluate the failure with respect to Maintenance Rule program guidelines.

b. Findings

No findings of significance were identified

.2 Routine Maintenance Effectiveness Observations

a. Inspection Scope (71111.12)

The inspectors evaluated Entergy’s work practices and follow-up corrective actions for the auxiliary feedwater (AFW) system to assess the effectiveness of Entergy’s maintenance activities. The inspectors reviewed the performance history and assessed the extent of condition determinations for issues with potential common cause or generic implications to evaluate the adequacy of corrective actions taken. The inspectors reviewed Entergy’s problem identification and resolution of issues to evaluate whether Entergy had appropriately monitored, evaluated, and resolved the issues in accordance with Entergy procedures and the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance." In addition, the inspectors reviewed selected systems, structures, and components (SSC) classification, performance criteria and goals, and Entergy's corrective actions that were taken or planned, to verify whether the actions were reasonable and appropriate. The following procedures and documents were reviewed:

- Maintenance Rule Basis Documents for the AFW System
- System Health Reports for the AFW System
- Administrative Procedure AP-62, “Maintenance Rule.”
- Final Safety Analysis Report Chapter 10, Steam and Power Conversion System
- 4th Quarter 2003 System Health Report for the AFW System
- Condition Report Nos. IP3-2001-04580; IP3-2002-00806; IP3-2002-00807; IP3-2002-02082; IP3-2002-03510; and IP3-2003-00764.
- WO IP3-02-014404, replacement of main steam isolation valves (MS-PCV-1310A & B) to the trubine-driven AFW pump.

b. Findings

No findings of significance were identified

1R12 Maintenance Effectiveness (Bienniel)

a. Inspection Scope (71111.12B)

Biennial Evaluation Inspection

The inspectors reviewed the licensee’s periodic evaluation required by 10 CFR 50.65(a)(3) for Indian Point 3 to verify that SSCs within the scope of the Maintenance Rule were included in the evaluation, and that the balancing of reliability and unavailability for those SSCs was given adequate consideration. The inspectors reviewed Entergy's most recent periodic evaluation report that covered the period of June 2001 through April 2003.

The inspectors performed a detailed review of the two systems currently classified as (a)(1) status at Indian Point 3:

- 345 kilovolt (KV) Electrical Distribution System
- Circulating Water System

During the review of these systems, the inspectors verified that: 1) goals and performance criteria were appropriate; 2) industry operating experience had been considered; 3) problem identification and resolution of maintenance rule related issues were addressed; 4) corrective action plans were effective; and 5) system performance was being effectively monitored. The inspectors verified that adjustments were made in action plans for the SSCs in (a)(1) status as a result of the licensee's review of system performance against established goals. The inspectors reviewed documentation for the SSCs to verify that Entergy balanced reliability and availability/unavailability and adjusted (a)(1) goals, as necessary.

The inspectors also reviewed documentation for the two systems that Entergy had changed from (a)(1) status to (a)(2) status during the periodic assessment period:

- Engineered Safeguards Initiation Logic
- Boric Acid Heat Trace

The inspectors reviewed the licensee's action plans for these systems, which included evaluation of industry operating experience, proposed system modifications, and additional equipment monitoring. The inspectors verified that the (a)(1) goals for the systems had been satisfied, and that the return of the systems to (a)(2) status was appropriate.

The inspectors selected a sample of high risk significance SSCs that had been in (a)(2) status:

- Auxiliary Feedwater System
- Emergency Diesel Generators
- Safety Injection/recirculation System,
- DC Power Distribution System

The inspectors verified that Entergy had established appropriate Maintenance Rule performance criteria for these systems, and that Entergy had examined any functional failures experienced by these SSCs against those performance criteria for consideration of changing the SSC to an (a)(1) status.

The inspectors also verified that Entergy had established and implemented a preventive maintenance program to manage preventive maintenance activities for systems in both (a)(1) and (a)(2) status. A sample of risk significant systems in (a)(1) and (a)(2) status was reviewed to verify the adequacy of performance monitoring and scheduled maintenance.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Control

a. Inspection Scope (71111.13)

During refueling outage 3R12, the inspectors reviewed maintenance risk assessments, work request tags (WRTs), corrective maintenance WO packages for emergent and scheduled work, observed the repair activities in the plant, and discussed the degraded conditions with cognizant plant personnel (system engineers, technicians, and maintenance workers). The following activities were reviewed:

- WO IP3-02-16871: 480 Volt Bus 5A Outage:

  480 volt Bus 5A was de-energized for preventive maintenance from April 8 through 11, 2003, in accordance with WO IP3-02-16871. Prior to the bus outage, the inspectors independently reviewed the electrical loads supplied by the 5A bus that would be lost and assessed the impact to the plant based on existing plant conditions. The inspectors evaluated the licensee's risk assessment for the bus outage to ensure it comprehensively addressed the equipment that would be without power and the effects on the plant with respect to shutdown risk. The inspectors also reviewed the plant's "protected equipment" list to verify single trains of safety-related equipment were placed in a protected status until the bus was restored. The inspectors also evaluated the adequacy of the 3R12 Scheduled Risk Assessment for the bus outage and the contingency plan for spent fuel pit cooling (Risk Assessment Contingency Plan 8) to ensure that the loss of cooling to the spent fuel pool risk was minimized and back-up cooling methods were appropriate.

- WOs IP3-03-02632 and IP3-03-16044: Degraded Spent Fuel Pool (SFP) Cooling Systems.

  On April 20, 2003, the inspectors performed a risk assessment of the spent fuel pool cooling systems while associated components were in a degraded condition. The 31 SFP pump was out of service due to an oil seal failure and the 32 SFP pump was in a degraded condition due to excessive oil leaking around its shaft seal. The backup spent fuel pool cooling system (BUSFPCS) was out of service due to a primary to secondary leak in its heat exchanger that was caused by a water hammer transient during system start-up. These problems were noted in Condition Reports CR-IP3-2003-2373, -2577, and -2602. The inspectors reviewed the licensee's contingency plans to maintain adequate pool cooling, which included stationing a watch-stander in the SFP pump area to continuously monitor the 32 pump and to maintain its oil level. The inspectors also reviewed the action plan to repair the 31 pump and return it to service, and the action plan to repair the BUSFPCS heat exchanger. The inspectors evaluated how the licensee incorporated this emergent work into the daily work schedule to ensure that the risk was appropriately defined and minimized, and that the daily risk assessment was updated as required until the 31 and 32 SFP pumps were restored and returned to service.

- WO IP3-03-17713: 31 Heater Drain Pump (HDP) Elevated Seal and Jacket Water Temperatures:

  On May 20, 2003, the licensee identified that the jacket and seal water cooling temperatures for the 31 HDP were elevated approximately 40F above normal (CR-IP3-2003-03188). Further analysis showed the turbine hall closed cooling (THCC) system lines that provide cooling to the HDP's heat exchanger had restricted flow upstream due to blockage in the lines from corrosion buildup. On June 5, the licensee installed a temporary cooling system by "hot tapping" the installed THCC lines and providing cooling flow from a city water manifold in accordance with temporary alteration TA-03-3-054. The inspectors evaluated the work based on the potential plant transient risk involved and reviewed the temporary alteration and work package for WO IP3-03-17713. The inspectors observed the work in the field to verify effective work controls were established and implemented. The inspectors also evaluated the licensee's risk assessment for the work and reviewed the licensee's contingency plans to mitigate potential problems to ensure they were appropriate in scope and could be properly implemented by the operators. The inspectors also verified that guidance was available to the operators to prevent an isolation of city water to the 31 HDP heat exchanger, and to respond to an inadvertent loss of city water while the temporary alteration was in place.

- WO IP3-03-17724; Repair of Conoseal No. 5; Boron Accumulation on Lower Clamp Assembly

  On May 23, 2003, during monthly vapor containment (VC) checks for boric acid deposits, the licensee discovered boron crystals on the lower clamp assembly of Conoseal No. 5 (CR-IP3-2003-3266). The licensee determined that the Conoseal joint leak was not an operability issue since it was not reactor coolant system (RCS) pressure boundary leakage, and the leak rate did not exceed the Technical Specifications limit for identified RCS leakage. The leakage was not detectable by any plant instruments (e.g., the VC particulate and gaseous radiation monitors). The licensee developed an action plan (IDSE-APL-03-013) to perform weekly inspections inside the VC to observe the progress of the leak, to develop a seal repair package, and to establish maximum acceptable leakage criteria for plant operators. The inspectors entered the VC with the licensee on May 29, June 12, and June 17 to evaluate the condition of the Conoseal joint leak.

On June 12, 2003, the licensee determined that the leak was “active,” based on the rate of accumulation over the previous week. The Inspectors discussed the risk of the leak on continued plant operations with cognizant engineering and operations personnel, and evaluated the licensee’s efforts to factor the Conoseal inspections into other work activities performed inside the VC. The Conoseal joint was subsequently repaired when the plant entered a forced maintenance outage following a reactor trip on June 22, 2003.

- WOs IP3-03-03197 and IP3-01-290800; Overhaul of 31 condenser valve HD-LCV-1127

  On May 21-23, 2003, the licensee repaired an air leak in the valve operator for a feedwater heater drain tank bypass line to 31 condenser valve HD-LCV-1127 (CR-IP3-2003-03189). This work was part of an overhaul of the valve to resolve longstanding equipment performance problems.

- WO IP3-03-03125: On May 21, 2003, the inspectors observed the licensee’s troubleshooting and measurements of the electro-hydraulic control (EHC) piping for the 33 main turbine stop valve in preparation for the repair of a significant oil leak (CR-IP3-2003-03279).

b. Findings

No findings of significance were identified

1R14 Personnel Performance During Non-routine Plant Evolutions and Events

a. Inspection Scope (71111.14)

.1 Offsite Grid Disturbance

On April 28, 2003, a local grid disturbance caused the loss of all Technical Specifications required sources of 138KV offsite power to Indian Point 3. One non-TS required source remained in service for approximately five minutes, and prevented a plant transient until the normal feeders were restored. The inspectors responded to the IP3 control room to observe the operators’ response to this event. The electrical perturbations resulted in multiple alarms and plant equipment problems including a trip of the 32 rod drive motor-generator and central control room (CCR) air conditioner compressors, an auto-start of the 32 component cooling water (CCW) pump, a transfer of the 33 static inverter to its alternate power supply, a transfer of the 32 main transformer auxiliaries to their emergency power supply, and a trip of the traveling water screen wash pumps. The inspectors evaluated the aggregate effects on overall plant safety that these equipment problems and realignments had on mitigating systems. The inspectors also observed operator actions to restore the plant to its normal system configuration.

After discussions with Consolidated Edison, the licensee determined the grid disturbance resulted in the loss of all qualified 138KV sources of power, credited in the design basis of the plant, for approximately five minutes. Offsite 138KV power was maintained by one non-qualified source supplying IP3's 138KV ring bus in the Buchanan Switchyard.

.2 Automatic Reactor Trip

On June 22, 2003, the plant automatically tripped at 100% power when 345KV output breaker No. 3 failed. The inspectors responded to the site to monitor the licensee's actions following the trip. The inspectors evaluated plant performance during the transient to verify the plant responded within its design limitations and observed operator actions in the control room to maintain the plant in a stable condition. Several minor plant anomalies following the trip were noted by the licensee. The inspectors reviewed these issues and ensured that appropriate corrective actions were implemented.

.3 Plant Start-up Special Evolution

On June 26, 2003, the inspectors observed a special evolution to start up the reactor following a five-day forced outage for maintenance. The inspectors reviewed plant operating procedures POP 1.2, "Reactor Startup," and POP 1.3, "Plant Startup from Zero to 45%." The inspectors attended the special evolution pre-job briefing and observed operators in the control room to verify procedural adherence. The inspectors observed the operators to ensure that formal communications were maintained throughout the evolution and that alarm response actions were adhered to. The inspectors also verified that proper supervisory controls were maintained for the operators-in-training who were conducting their required start-up evolution practical factors.

.4 Unavailability of Emergency Planning Zone Sirens

The inspectors evaluated the licensee's problem identification and resolution activities associated with a number of emergency planning siren failures reported in accordance with 10CFR50.72 between February and June 2003. The inspectors observed the on-line monitoring of siren performance at the emergency operations facility, reviewed the licensee's assessment of overall system availability, and discussed proposed corrective actions with cognizant licensee personnel.

The inspectors consulted NRC Inspection Manual Chapter (IMC) 0609, Appendix B, for examples of a loss and/or degraded risk significant planning standard (10 CFR 50.47(b)(5) associated with the public alert and notification system.

The NRC previously documented a review of emergency planning siren failures in report 50-247/03-03, Section 4OA2.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope (71111.15)

The inspectors reviewed various condition reports (CRs) on degraded or non-conforming conditions that raised questions on equipment operability. The inspectors also reviewed the licensee's operability determinations (ODs) for technical adequacy, whether or not continued operability was warranted, and to what extent other existing degraded systems adversely impacted the affected system or compensatory actions. The following CRs and ODs were evaluated:

- CR-IP3-2003-2367: 32 Safety Injection (SI) Pump Operation at Zero Flow.

  On April 15, 2003, the 32 SI pump was started to raise accumulator level. Due to a configuration control error the pump's discharge and recirculation valves were shut. When the pump was started there was no discharge path available and the pump was run under zero flow (dead head) for three minutes and 12 seconds.

  To evaluate pump operability, the inspectors reviewed data provided from the plant computer on pump discharge and suction pressure and the licensee's calculations to determine initial and final water temperature in the pump volute. This data was used to determine if boiling had occurred in the pump. The inspectors also evaluated pump data collected on April 18, during the performance of quarterly surveillance 3PT-Q116B. This data included pump vibration readings, bearing temperatures, flow rate, and discharge pressure. This data was compared to the previous quarterly surveillance data to provide a reference point.

- CR-IP3-2003-2931: Incorrect Amperage Breaker Installed for the 32 EDG Pre-lube Pump.

  On May 6, 2003, the licensee discovered that a 20 ampere (amp) molded case circuit breaker had been substituted for a 10 amp breaker on the 32 EDG pre-lube pump. This was identified during an extent-of-condition review after an error was discovered in a breaker replacement work package on the 33 EDG. WO I3-027708502 was being worked to replace three circuit breakers on the 33 EDG. While work was in progress, the licensee found that the package called for the replacement of a 10 amp breaker with a 20 amp breaker. Similar work on the 32 EDG was performed last quarter and therefore was evaluated under the extent-of-condition review.

  On May 7, the licensee completed an operability determination (OD 03-14) to verify the pre-lube pump could still perform its intended function with the 20 amp breaker installed. The inspectors evaluated the licensee's analysis to verify the equipment was operable and reviewed the circuit protection scheme to ensure it was not adversely impacted by the higher rated breaker. Overload heaters in the circuit provided over-current protection analysis and demonstrated the 20-amp breaker did not significantly impact the short circuit analysis for the system. The inspectors also analyzed the conductor sizing to verify there would be no adverse impact from the increase in breaker current rating. The licensee determined the installed 20 amp breaker would not prevent the pre-lube pump motor from performing its intended function.

- CR-IP3-2003-2534: Failure of Auto-SI Reset.

  During the performance of surveillance test 3PT-R003D, “Station Blackout Test” on April 18, 2003, the licensee found that the automatic blocking of an SI actuation signal upon SI reset did not operate properly. This function was designed to prevent re-initiation of safety injection once reset by the control room operators during EOP recovery actions. During the test, the “Auto-SI Block” lights did not illuminate as expected once the SI reset buttons were pressed. The lack of indication did not satisfy the test acceptance criteria.

  The licensee completed an operability determination (OD 03-12) of this anomaly on April 20, 2003. The inspectors reviewed the OD to ensure it adequately addressed the problem and to verify the adequacy of its technical content. The inspectors noted that the evaluation credited operator action to manually block the safety injection signal once this problem presented itself. In accordance with emergency operating procedure RO-1, “BOP Operator Actions During the Use of EOPs,” Step 14, the operator would manually block safety injection if the “SI ACTUATED” light was not extinguished. On review of the scenario that occurred during testing, the inspectors determined in this particular scenario that the operators would not take the actions credited by the evaluation since the “SI ACTUATED” light was extinguished after SI was reset. This would place the operators in a position in which SI could re-initiate, hampering their recovery efforts. CR-IP3-2003-03778 was written to address this issue. The licensee determined that even if SI was actuated after being reset by the operators it would not prevent the system from performing its mitigating function.

- CR-IP3-2003-3851: Intermediate Range Nuclear Instrument (IRNI) Indicating Meters Failed Acceptance Criteria.

  On June 24, 2003, the licensee found that the indicating meters for IRNIs N-35B and N-36 failed to meet their acceptance criteria during the performance of 3PT-V002. This discrepancy was documented in the corrective actions program and an engineering evaluation was requested to confirm instrument operability. Engineering evaluated this issue and determined that there was no operability issue associated with this discrepancy since other indications were available to the operators. Engineering also determined that the acceptance criteria for these particular indicators was too narrow based on the meter range and accuracy.

The inspectors reviewed the engineering evaluation to verify its technical accuracy and to ensure it adequately addressed the indicated deficiency. The inspectors evaluated the licensees conclusions that the instruments were operable and reviewed the test data. The inspectors also evaluated how this indication error could impact the operators during normal and transient conditions.

b. Findings

Introduction. A Green non-cited violation was identified involving inadequate procedural compliance which resulted in running the 32 SI pump with no available discharge path for three minutes and 12 seconds. This was determined to be a violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures and Drawings.”

Description. On April 14, 2003, operators initiated procedure SOP-SI-001, “Safety Injection System Operation,” to fill the SI accumulators via the safety injection pumps. A prerequisite for the use of the procedure was that the system be aligned in accordance with check-off list COL-SI-1, “Safety Injections System,” which aligns the system for normal full power operation. Since the plant was in a refueling outage, the operators determined that this prerequisite was not applicable (N/A) for the current plant conditions. The process for making a step N/A is governed by Administrative Procedure AP-4, “Procedure Use and Adherence.” AP-4 allows procedure steps to be omitted based on plant conditions, as long as the intent of the step was met. The operators performed a cursory line-up verification by a review of the Shift Operations Management System (SOMS) and a training drawing, to ensure a flow path was available through the 32 SI pump.

Concurrent with the SI accumulator fill evolution, on April 14, operators initiated procedure SOP-RP-020, “Draining the RCS / Refueling Cavity,” in preparation to drain the refueling cavity. The valve line-up associated with the cavity drain required SI pump recirculation valves SI-MOV-842 and 843 to be shut, which isolated the recirculation path of all three SI pumps. These valves were required to be open per COL-SI-1. The operators performing SOP-SI-001 failed to notice these valves were shut while performing their cursory review of the system line-up.

When the 32 SI pump was started in accordance with the accumulator fill procedure, there was no discharge path available. The pump ran for three minutes and 12 seconds in this condition before the operators took action to secure the pump. Running the pump in this condition caused a rapid rise in pump fluid temperature and had the potential to cause severe damage to the pump if saturation conditions were reached. The pump vendor had supplied the licensee with data stating that pump damage would occur it the pump ran at shut-off head for greater than three minutes, using the maximum RWST temperature as a conservative bounding condition. The licensee initiated actions to verify there were no operability concerns with the pump due to running it at shut-off head.

Analysis. The inspectors determined that the performance deficiency was the operators' failure to maintain proper configuration control by not verifying the safety injection system was aligned to support pump operation. The finding is greater than minor because it's associated with the shutdown configuration control and human performance attribute of the Mitigating Systems cornerstone objective. The inspectors conducted a Phase 1 SDP screening and determined that the failure to adequately maintain configuration control due to a failure involving procedural compliance of the SI system was of a very low safety significance since running the pump at shut-off head did not adversely impact the pumps operating capability.

Enforcement. Administrative procedure AP-4 requires that procedural steps can only be signed-off as "not applicable" if the intent of the step has been met. The intent of the prerequisite for SOP-SI-001 requiring the use of COL-SI-1 was to ensure the SI system was aligned for proper operation, and that the SI pumps were provided with a suction and discharge path. 10 CFR 50, Appendix B, Criterion V states that activities affecting quality shall be prescribed by procedures of a type appropriate to the circumstances and shall be accomplished in accordance with those procedures. Contrary to the above, the licensee failed to properly implement procedure AP-4 on April 14, 2003, in that the alignment verification performed was inadequate to ensure proper system alignment, and therefore the intent of the prerequisite step was not met. Because this failure to adequately implement procedure AP-4 is of very low safety significance and has been entered into Entergy's corrective action program (CR-IP3-2003-02367) this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (**NCV 50-286/03-06-01)**.

1R16 Operator Workarounds

a. Inspection Scope (71111.16)

The inspectors performed a review of operator workarounds to determine the cumulative effects upon the reliability and availability of plant systems, the potential for mis-operation of a system, and operators' ability to respond to plant transients in a timely and effective manner. The review included the transient and non-transient operator workaround lists and the control room deficiency list. In addition, the inspectors sampled the work control and CR databases to ensure potential workarounds were properly characterized.

During the 3R12 refueling outage, the licensee resolved all transient operator workarounds, except one which required control room operators to manually adjust the output voltage on the Station Auxiliary Transformer (SAT) after starting large loads supplied by Bus 6A. Engineering was evaluating this condition and preparing a modification to change the undervoltage relays on all 480 volt buses in order to alleviate this problem.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope (71111.19)

The inspectors reviewed post-maintenance test (PMT) procedures and associated testing activities to assess whether: 1) the effect of testing in the plant had been adequately addressed by control room personnel; 2) testing was adequate for the maintenance performed; 3) acceptance criteria were clear and adequately demonstrated operational readiness consistent with design and licensing documents; 4) test instrumentation had current calibrations, range, and accuracy for the application; and 5) test equipment was removed following testing. The following PMT activities were observed and evaluated:

- WO IP3-03-14427: Fuel Storage Building Exhaust Fan.

  On April 2, 2003, the Fuel Storage Building (FSB) ventilation exhaust fan failed (CR-IP3-2003-01760). The FSB ventilation exhaust consists of a single train, and is used to discharge filtered air from the FSB. It is also important for maintaining a proper work environment during fuel movement. The inspector observed repair work performed on the fan assembly, belt alignment between the motor and fan, and the post-work test completed on April 3 to verify proper alignment and operation. The test consisted of a shaft runout measurement to verify eccentricity was within specification, visual inspections of the housing assembly, belts and dampers, and a motor/fan vibration analysis. The licensee also performed portions of procedure 3PT-R32A, “Fuel Storage Building Filtration System,” to verify proper air flow rates in the FSB. The inspector reviewed the scope of the testing to ensure it would encompass all the replaced components and also evaluated the test data for completeness and accuracy.

- WO IP3-03-15438: 32 AFW Flow Control Valve.

  On April 13, 2003, surveillance test 3PT-R007A, “31 & 33 ABFPs Full Flow Test,” failed its acceptance criteria due to less than minimum required flow through the 32 AFW flow control valve when the cutback controller was controlling flow. During troubleshooting, it was found that the while the valve was satisfactorily set-up in accordance with air-operated valve diagnostics, it had a slight calibration bias. This caused the valve to open 5% less than required for a given input signal from the cutback controller. The licensee determined that the valve required re-calibration, and this was performed on April 14. The inspector reviewed the work order and evaluated the post-work test to ensure it was comprehensive enough to ensure the component was operating satisfactorily. The surveillance was completed satisfactorily on April 14. The inspectors observed the surveillance and reviewed the data to verify proper flow control while the cutback controller was in operation.

- WOs IP3-03-18567 and IP3-03-18684: 345 KV Output Breaker No. 1.

During a forced maintenance outage on June 26, 2003, breaker No.1 failed its acceptance testing due to an out-of-specification closing time. The closing time was 180 milliseconds with a specified band of 105 -130 milliseconds. During troubleshooting, the licensee determined that the solenoid operator for the valve that controls closing air to the breaker contacts required replacement. The inspectors observed the work performed and evaluated the post-work test criteria to ensure that it had a sufficient scope for the work performed. The inspectors reviewed the test configuration and observed the testing after the maintenance was complete. The retest failed with a breaker closing time of 80 milliseconds. After discussions with the vendor, licensee engineering staff determined that the closing time was acceptable. It was found that there was a discrepancy between the licensee and vendor concerning the way breaker speed was calculated. Once the dead time (time from depressing the actuation switch to breaker movement) was removed from the calculation the breaker speed was within the vendor's recommended times, even though it did not meet the licensee's test criteria. The inspectors reviewed the vendor's data and the licensee's engineering evaluation for accuracy and technical content. Upon completion of the post-work test, the licensee determined the breaker was acceptable for service.

- WO IP3-02-22909: 33 Auxiliary Boiler Feedwater Pump Vibration Inspection following the quarterly preventive maintenance on the pump motor; performed on June 9, 2003

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

.1 Review of Outage Risk Assessment

a. Inspection Scope (71111.20)

Prior to entering refueling outage 3R12, Entergy performed a detailed outage risk assessment in accordance with administrative procedure AP-9.2, "Outage Risk Assessment," Rev 6. The inspectors reviewed the risk assessment and outage activities to ensure that appropriate consideration was given to minimize equipment unavailability, and to mitigate/compensate for reductions in attributes such as: 1) reactivity control; 2) core cooling; 3) power availability; 4) containment integrity; 5) spent fuel cooling; and 6) RCS inventory control. The inspectors observed that the licensee conducted a qualitative evaluation of the daily shutdown risk associated with planned outages of both safety and non-safety related systems which contribute to these six attributes. In addition, the licensee assigned an overall risk characterization based upon the collective risk of all systems that were out-of-service at any given time. The inspectors noted that as a result of the daily outage risk assessments, Entergy made some changes to the outage schedule and developed "Defense in Depth Contingency

Plans" for those outage configurations which could not be otherwise modified to minimize the overall risk. The inspectors examined the daily risk assessments for April 3 and 4, in detail, together with their associated contingency plans.

b. Findings

No findings of significance were identified.

.2 Plant Shutdown

a. Inspection Scope (71111.20)

The inspectors observed activities in the control room and in the plant during the shutdown. The inspectors verified the operators took timely and appropriate actions in accordance with procedures E-0, "Reactor Trip or Safety Injection," and ES-0.1, "Reactor Trip Response," when the reactor was manually tripped at 12:03 a.m. on March 29, 2003. The inspectors observed the operators respond to changing plant conditions using alarm response procedures and abnormal operating procedures, as appropriate. The inspectors evaluated operator actions for adequacy to ensure a smooth down-power and verified that the control room operators adhered to the cooldown limits. The inspectors evaluated the shutdown, referencing procedures POP 3.1, "Plant Shutdown," and POP-3.3, "Hot to Cold Shutdown." The plant was cooled down to less than 350 degrees F with the AFW system, at which time the residual heat removal (RHR) system was placed into service. The inspectors verified that operator actions were appropriate to stabilize the plant on RHR cooling. The plant was subsequently cooled down to less than 200F and entered Mode 5 at 11:19 p.m. on March 29, 2003. Shortly after the plant was tripped, an electrical short and small fire occurred in the 32 condensate pump motor. The inspectors observed operator actions in accordance with ONOP-FP-1 to address the fire, which was extinguished in less than 15 minutes.

The inspectors evaluated operator response to equipment issues which arose during the shutdown and cooldown. These were documented and evaluated by the inspectors in the following condition reports:

- CR-IP3-2003-1585: 32 Condensate pump motor fire
- CR-IP3-2003-1589: Multiple 480V bus under-voltage alarms
- CR-IP3-2003-1591: 34 Atmospheric steam dump difficult to operate from control room
- CR-IP3-2003-1609: Failure of pressurizer pressure controller
- CR-IP3-2003-1606: 31 reactor coolant pump (RCP) thermal barrier low differential pressure
- CR-IP3-2003-1607: Accumulator isolation valve would not close from the control room
- CR-IP3-2003-1658: Feedwater water hammer

Feedwater Water Hammer:

On March 28, 2003, during shutdown of the secondary plant, outage workers and operators inside the containment noted a water hammer transient in the main feedwater piping shortly after the 31 and 32 AFW pumps were secured (CR-IP3-2003-01658). The licensee initiated actions to evaluate any potential damage to system piping and to determine the cause of the water hammer. A visual inspection of the piping and restraints was performed by structural engineering and no damage was observed. The licensee considered the cause of the water hammer to be rapid condensation of steam in the feedwater lines downstream of the feedwater check valves due to mixing of the hot stagnant feedwater with the sub-cooled water supplied by the AFW pumps. The licensee determined that the loss of the 32 condensate pump earlier in the shutdown could have been a contributing factor since the condensate system was shut down earlier than anticipated which increased the amount of residual heat retained by the stagnant feedwater.

The inspectors evaluated the licensee’s response to this event to ensure it was thorough and that the event was adequately understood. The inspectors also reviewed the apparent cause evaluation for technical accuracy and discussed the analysis with NRC technical experts. Shortly after the water hammer, the inspectors performed an independent walk-down of the auxiliary and main feedwater piping paying particular attention to pipe supports and whip restraints. The inspectors noted several minor anomalies which were discussed with licensee engineering staff to ensure they would not impact system integrity.

b. Findings

No findings of significance were identified.

.3 Refueling and Reactor Disassembly

a. Inspection Scope (71111.20)

Reactor Disassembly

The inspectors toured the vapor containment (VC) and observed a variety of refueling work activities to ensure that appropriate radiological controls and work practices were adhered to. The inspectors observed the following activities:

- Reactor vessel stud de-tensioning and removal
- Seal table disassembly and swagelock valve replacement
- Reactor vessel head lift preparations
- Reactor vessel internal package lift preparations
- Fuel transfer cart troubleshooting and wet checks
- Reactor coolant pump back-seating
- Reactor vessel head non-destructive examination equipment set-up and initial checks

On April 3, the inspectors observed the reactor head lift and the disengagement and lift of the reactor upper internals package.

Damaged Fuel Assemblies:

During the reactor core off-load, the licensee found that the guide tubes at the upper end of two fuel assemblies were physically damaged. Both assemblies (BB55 and BB56) contained secondary sources and the licensee noted the damage while trying to remove the secondary sources (CR-IP3-2003-02122). Following a closer video inspection and discussions with the fuel vendor, the licensee determined that the upper nozzle on each assembly had been deformed after the assembly was placed in a core location that was incompatible with a secondary source. The fuel vendor had incorrectly specified the wrong locations for the secondary sources during the last core re-load, which created an interference with the reactor upper internals.

The inspectors discussed this discrepancy with the licensee’s reactor engineering staff, and reviewed the root cause report for accuracy and completeness. The inspectors also evaluated the licensee’s corrective actions to ensure they were sufficient to prevent a recurrence and were appropriate for the identified problems.

Refueling Operations

On April 5 through 7, 2003, the inspectors observed fuel off-load activities from the containment manipulator crane and observed operation of the containment fuel transfer system. The inspectors also observed refueling operations in the spent fuel pool and in the control room. The inspectors reviewed procedure RP-3, Section 2.2 “Fuel Movement Requirements - Core Unload,” and the Westinghouse Refueling Manual. The inspectors verified that fuel movement was performed as documented in the procedures and that the fuel handling equipment was used as intended. The inspectors also evaluated the effectiveness of fuel sipping operations (to detect failed fuel) and upper nozzle inspections, and reviewed procedures RP-3, Section 2.4 “Fuel Assembly Insert Changeouts” and RP-3, Section 3.1 “Fuel Movement Requirements.”

During April 11 through 14, the inspectors observed fuel re-load operations and verified fuel movement was completed in accordance with refueling procedure requirements. Throughout the refueling process the inspectors periodically monitored foreign material exclusion controls around the reactor cavity and the spent fuel pool to verify the appropriate controls were maintained.

Reactor Vessel Upper and Lower Head Boric Acid Inspections

On March 30, 2003, the inspectors accompanied engineering personnel on a visual inspection of the reactor vessel lower head for the presence of boric acid. No signs of active leakage were observed. Two minor issues were documented in CR Nos. IP3-2003-1659 and IP3-2003-1663.

On April 10, the inspectors observed the reactor vessel upper closure head after the licensee removed the shroud and head insulation surrounding the control rod drive mechanisms (CRDMs) to verify that boric acid was not deposited from potential RCS pressure boundary leaks.

b. Findings

No findings of significance were identified.

.4 Licensee Control of Outage Activities

a. Inspection Scope (71111.20)

Clearances

The inspectors verified that tagout activities were properly controlled and that equipment was appropriately configured to support the function of the clearances. The inspectors reviewed the following protective tagout to ensure that the licensee followed the appropriate procedures while hanging and removing the clearances.

- Clearance 3-480V-BUS 5A MELC: Bus 5A outage for preventive electrical maintenance

The inspectors also verified that a sample of other tags and clearances were properly installed and removed, that equipment was appropriately configured to support the function of the clearance, and that the use of clearances and tagging ensured that maintenance activities were conducted under safe conditions. The inspectors observed the installation and removal of several protective tag outs (PTOs) and caution tag outs (CTOs) to ensure that the licensee followed the tagging process outlined in administrative procedure AP- 10.1, “Protective Tagging.” The inspectors also observed activities in the work control center and the performance of the field support supervisor who approved tag outs, dispatched personnel to install or remove the tags, and provided final disposition of removed tags. Further, the inspectors reviewed plant configurations caused by the clearance tags to ensure that the licensee maintained the minimum required boron injection pathways.

Reactor Coolant System Instrumentation

During the refueling outage, the operators used the normal RCS pressure and temperature indications available in the control room. RCS level instrumentation were temporary devices installed and configured to provide redundant level indication. Entergy installed the two channel Mansell Monitoring System which used solid state pressure transmitters to provide accurate level indication during changing RCS conditions. The Intermediate Leg Level Indication System (ILLIS) was also installed, which used redundant water columns monitored by a remote video monitor. The inspectors monitored the status of these level systems throughout the outage to ensure that the level indication used by the operators remained available and accurate.

Electrical Power

The inspectors reviewed the licencee’s electrical bus and EDG outage schedule to verify it was appropriately risk assessed and to review the impact on available plant mitigating systems. The inspectors performed a detailed review of the 480V Bus 5A outage (see Section 1R13). The inspectors also verified the defense-in-depth procedures for electrical maintenance were adequate for plant conditions. During plant tours, the inspectors periodically verified that the licensee maintained an enhanced level of protection for electrical power supplies to safety-related equipment.

Residual Heat Removal System Monitoring

After the plant entered mode 3 operations on March 29, the licensee placed the 32 RHR pump into service to continue the plant cooldown. The inspectors reviewed the RHR system operating procedure, SOP-RHR-1, “Residual Heat Removal System,” and reviewed system operating parameters to verify that minimum system flow was maintained above 1000 gallons per minute, as required, and that the system was functioning properly. The inspectors periodically monitored RHR system operation throughout the plant cooldown.

Spent Fuel Pool Cooling Operation

During fuel transfer periods, and when all fuel assemblies were stored in the spent fuel pool, the inspectors verified that the pool temperatures were properly maintained by the spent fuel pool cooling system. The core was completely offloaded into the spent fuel pool during the 3R12 outage and the licensee maintained both the normal and backup spent fuel pool cooling systems in service. Throughout the outage, fuel temperatures were maintained less than 120 degrees F with both systems in service. The licensee secured the back-up system once the core reload was complete.

On April 8, primary spent fuel pool cooling was inadvertently interrupted due to a configuration error when the licensee de-energized 480V Bus 5A. The inspectors reviewed the event for safety significance and evaluated Entergy's follow-up actions. On April 20, the spent fuel pool cooling system was operated in a degraded condition due to several mechanical problems. The inspectors performed a detailed risk assessment for these conditions (see Section 1R13).

Inventory Control

During periodic control room and plant walkdowns, the inspectors verified that the sources and flow paths for makeup to the reactor coolant system and refueling cavity were maintained in accordance with the licensee's outage risk assessment. The inspectors also periodically monitored the licensee's configuration controls to assure that the RCS boundary valves were properly controlled as isolation boundaries.

During the SG eddy current testing on April 8, with reactor core re-load operations in progress, an undersized drain plug in the 32 SG primary side became loose and was ejected (under pressure from the RCS and refueling cavity water). This created a leak path for RCS water to spill from the open SG manway onto the containment floor. Refueling operations were immediately halted while the licensee took actions to obtain a replacement plug to stop the leakage. However, approximately 5000 gallons of RCS inventory were directed into the containment sump before the leak was stopped. While the leak was in progress, operators provided make-up to the refueling cavity to avoid a drop in the water level. The inspectors observed the licensee's actions during recovery from this event, and discussed their actions to stop the leak. After the leak was stopped, the inspectors reviewed the licensee's root cause analysis and actions to prevent a recurrence.

Containment Closure

The inspectors reviewed Technical Specification requirements governing containment closure during refueling activities, plant restart and power operations, and evaluated the licensee's process for completing containment closure.

On April 19, prior to entering operating Mode 2, the inspectors accompanied the licensee representatives in containment during a closeout inspection. The inspectors focused on the state of containment equipment and spaces, after all outage work was complete, to evaluate the readiness of the containment for power operations. The inspectors ensured that no uncontrolled equipment or material had been left which could challenge the sump system in the event of a design basis accident. The inspectors also performed a detailed inspection of the condition of all containment sumps (including the recirculation system sumps) to evaluate the condition of the sump screens to look for the presence of any solid material that could potentially degrade sump performance during postulated accident conditions. The inspectors identified several discrepancies related to missing sump grating hardware and excess debris left inside containment. These items were referred to the licensee and were documented in CR-IP3-2003-2569 for resolution.

c. Findings

32 SG Nozzle Dam Leak:

Introduction. A Green Non-cited Violation (NCV) was identified in that inadequate procedure quality and implementation resulted in the ejection of a steam generator (SG) bowl drain plug and the loss of approximately 5000 gallons of RCS inventory through a ½-inch drain line in the SG to the vapor containment (VC) sump. This was determined to be a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures and Drawings."

Description. On April 8, nozzle dams were installed on all SGs in preparation for in-service testing of the SGs concurrent with fuel reloading. The installation was performed in accordance with a Quality Assurance Category I (i.e., safety-related) Work Order No. IP3-020094100, which implemented a contractor's procedure. The WO covered the placement of a leak tight dam in the RCS hot and cold leg nozzles, and also a plug in a ½-inch drain line located in the cold leg bowls. During initial installation of the drain plug in the 32 SG, the plug was not secure and had to be reinstalled. The installer noted, at that time, the plug seemed to be slightly undersized. The installation instructions required one individual to install the nozzle dam and plug and then another individual verifies proper installation.

On April 10, the reactor cavity water level was raised in preparation for fuel transfer. This column of water applied approximately 13 pounds per square inch of pressure on the nozzle dam. While cavity level was being raised, leakage was noted around the bowl drain plug in the 32 SG and was estimated to be approximately one gallon per hour. The licensee took compensatory measures to monitor the water level in the bowl and to drain it, as necessary. At 5:00 a.m. on April 12, field personnel reported a leak from the 32 SG manway. Approximately 300 gallons of primary coolant had spilled out of the SG manway before actions were taken to pump the leakage directly to the VC sump. All fuel movement was suspended and make-up water was supplied to the RCS to maintain reactor cavity water level. Upon further investigation the licensee found that the bowl drain plug had been ejected from the drain line. At 10:30 a.m., a new drain plug was obtained and installed in the drain line to stop the leak. The inspectors estimated that the total RCS inventory loss was approximately 5000 gallons.

Analysis. The inspectors determined that this was a human performance deficiency involving the inadequate installation of the nozzle dam plug. The Work Order instructions for the plug installation did not specify the plug size. The inspectors noted that drawing TTMC 1440-C350 specified the inside diameter of the SG bowl drain opening was 0.52 inches. However, the licensee used a plug with a diameter of 0.50 inches. The instructions also failed to specify the proper acceptance criteria and did not provide any guidance on acceptable leakage. The finding is greater than minor and is associated with the configuration control, procedure quality, and human performance attributes that affect the Barrier Integrity cornerstone objective. This finding screened to Green via the SDP Phase 1 worksheet (Appendix G of Inspection Manual Chapter 0609). The inspectors determined that the failure to perform an adequate verification that the bowl drain plug was properly installed was of a very low safety significance since RCS inventory control was maintained and there was no rise in RCS temperature.

Enforcement. 10 CFR 50, Appendix B, Criterion V, states in part that activities affecting quality shall be prescribed by procedures of a type appropriate to the circumstances and shall be accomplished in accordance with those procedures. Criterion V also states that procedures shall include appropriate acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to the above, on April 8, 2003, the licensee did not verify that the bowl plug for the 32 SG was properly installed to prevent a loss of RCS inventory. In addition, the licensee's instructions provided no acceptance criteria to ensure an adequate installation and did not account for the slightly larger drain hole size in 32 SG, which was documented in drawing TTMC 1440-C350. These deficiencies resulted in inadvertent loss of 5000 gallons of RCS inventory on April 10, 2003. Because this event is of very low safety significance and has been entered into the licensees corrective actions program (CR-IP3-2003-2274), this violation is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy **(NCV 50-286/03-06-02)**.

Loss of Primary Spent Fuel Pool Cooling

Introduction. A self-revealing Green finding was identified in that a configuration control error resulted in the loss of primary spent fuel pool (SFP) cooling when 480V Bus 5A was de-energized for planned maintenance while it was supplying power to the only running primary SFP pump.

Description. On April 8, maintenance was scheduled which required de-energizing the 480V safeguards Bus 5A, which supplies power to the No. 32 SFP pump. In accordance with the applicable Defense in Depth Contingency Plan C8, “Core Cooling,” with only one SFP pump available for service, the Back Up Spent Fuel Pool Cooling System (BUSFPCS) should be verified available and the single operable SFP pump should be placed in a protected status. On April 7, caution tags were placed on the No. 31 pump to place it in a protected status and the BUSFPCS was placed in service. The inspector determined that Temporary Operating Procedure, TOP-190, “480 Volt Bus 5A Outage,” was issued to provide step-by-step instructions to de-energize and re-energize Bus 5A. TOP-190, Attachment 1, “Prerequisites for De-energizing 480V Bus 5A & 6.9KV Bus 5,” included a sign-off step to ensure that the No. 31 pump was in service. Instead of performing a physical verification of the status of the SFP system pumps, the responsible operators performed this verification by reviewing the nuclear plant operator’s (NPO’s) log midnight status which showed the 31 pump was running. This log entry was incorrect, as the No. 32 pump was operating and had been in service since April 6. This human performance error, coupled with the operators’ inadequate verification of SFP pump operating status per TOP-190, resulted in the loss of primary SFP cooling when Bus 5A was de-energized.

The loss of primary SFP cooling flow was noted by a system engineer in the vicinity of the pumps, who promptly notified the control room operators. Approximately 15 minutes elapsed between the loss of primary cooling and the start of the protected No. 31 SFP pump. Because the BUSFPCS was in service, SFP temperature remained constant at 116 degrees F during this event.

Analysis. The inspectors determined that the loss of primary SFP cooling was a performance deficiency because the NPO logs were inaccurate and the operators did not adequately verify the operation of the protected SFP pump train. This finding is greater than minor since it is associated with the shutdown configuration control and human performance attributes that affect the Mitigating Systems cornerstone objective. The inspectors conducted an SDP Phase 1 worksheet screening and determined that the failure to adequately maintain configuration control of the SFP pumps was of a very low safety significance based on the short duration of the loss of normal cooling and that the BUSFPCS was in service at the time. No notable rise in spent fuel pool temperature occurred. This issue was entered into the licensees corrective actions program as CR-IP3-2003-2067. **(FIN 50-286/03-06-03)**.

Enforcement

No violation of regulatory requirements occurred.

.5 Reduced Inventory and Mid-Loop Operations

a. Inspection Scope (71111.20)

The inspectors evaluated the conduct of plant activities during periods of reduced RCS inventory and mid-loop operations. The inspectors reviewed the licensee's commitments associated with NRC Generic Letter 88-17 and verified they were adequately implemented. The inspectors also reviewed the configuration of plant systems to ensure they were consistent with the licensee's outage risk assessment and defense-in-depth procedures. The inspectors verified that controls were in place to prevent a loss of coolant inventory during mid-loop and reduced inventory conditions.

b. Findings

No significant findings were identified

.6 Monitoring of Heat-up and Restart Activities

a. Inspection Scope (71111.20)

From April 20 to 22, 2003, the inspectors witnessed control room activities and observed the plant heat-up to normal operating temperature. The inspectors reviewed the applicable startup procedures and verified that the operators maintained the plant within the heat-up rate limits. Documents that inspectors reviewed include the following:

- POP 1.1, Plant Heatup From Cold Shutdown Condition
- POP 1.2, Reactor Startup
- RA-7, Startup Physics Test Program
- RA-4, Zero Power Physics Test Program
- 3PT-V053A, Power Ascension Surveillance Requirements

On April 22, the inspectors observed the operators' pre-briefing and the reactor start-up to ensure that start-up procedures were appropriately adhered to. On April 23, the inspectors observed portions of low power physics testing. During measurements of dynamic rod worth, the licensee noted that the measured values differed significantly from the calculated values. Consequently, physics testing was secured and power level held constant while the licensee investigated this discrepancy. The problem was traced to an error in the rod worth measurement software supplied by the vendor. The inspectors evaluated the licensee's actions to determine the cause of this error (CR-IP3-2003-2655) and reviewed the root cause analysis performed by Entergy. Once corrected, the licensee resumed rod worth testing. Following low power physics testing on April 23, reactor power was raised to approximately 10%, and the main turbine was synchronized to the grid. During the continuing power ascension between April 23 and 27, difficulties operating the main turbine control valves required operators to trip the main turbine on several occasions to perform repairs. The inspectors evaluated the licensees actions to ensure there was minimal impact on reactor safety.

Findings

b. No significant findings were identified

1R22 Surveillance Testing

a. Inspection Scope (71111.22)

The inspectors observed portions of the following surveillance tests and reviewed the test procedures to assess whether: 1) the test preconditioned any of the components; 2) the effect of the testing was adequately addressed in the control room; 3) the scheduling and conduct of the tests were consistent with plant conditions; 4) the acceptance criteria demonstrated system operability consistent with design requirements and the licensing basis; 5) the test equipment range and accuracy were adequate for the application, and the test equipment was properly calibrated; 6) the test was performed in the proper sequence in accordance with the test procedure; and 7) the affected system(s) was properly restored the correct configuration following the test.

- 3PT-R003D, “Safety Injection Test;” performed on April 18 and 19, 2003
- 3PT-R131, “Reactor Coolant System Integrity Leak Test;” performed on April 21, 2003
- 3PT-Q116B, “32 Safety Injection Pump Functional Test;" performed on May 16, 2003
- 3PT-117B, “32 Containment Spray Pump Functional Test;” performed on May 23, 2003
- 3PT-Q96, “6.9KV UV/UF Analog Channel Functional Test;” performed on June 6, 2003
- 3PT-M79B, “32 EDG Functional Test;” performed on June 11, 2003
- 3PT-Q126, “Fan Cooler Unit Operational Test;” performed on June 11, 2003

b. Findings

No findings of significance were identified.

1R23 Temporary Modifications

a. Inspection Scope (71111.23)

During the week of April 26, the inspectors reviewed temporary alteration TA-03-044 which was installed to block servo oil passages in the 32 and 34 control valve dump valves on the main turbine. The alteration was required due to leak-by of the dump valve assemblies which would not permit oil pressure to build up high enough to operate the control valves (CR-IP3-2003-2707). The temporary alteration design involved the installation of a flange on the dump valve port openings to block a leak path.

The inspectors observed that the initial design of the alteration was inadequate because it allowed a communication path between high pressure oil and control oil, which caused excessive control oil pressure, quick opening of the control valve, and a subsequent rapid acceleration of the turbine which required operator intervention to reduce turbine speed (CR-IP3-2003-2762). The temporary alteration was redesigned to remove this communication pathway. The redesign was documented in temporary alteration change notice TA-03-044-001.

The inspectors reviewed the design of the temporary alteration, the engineering design verification, and the 10 CFR 50.59 screening against design basis documents to ensure the alteration would not adversely affect operating procedures or design parameters. The inspectors also assessed Nuclear Safety Evaluation 96-3-099 for adequacy and technical accuracy. The evaluation addressed the affects of blocking the dump valves and the potential increase in turbine overspeed in the event of a main generator full load rejection. This overspeed increase could occur because of the slower response time of the control valve to close with the dump valve blocked. The evaluation determined the turbine speed would still be within its design margin, even if all four dump valves were blocked. The inspectors also evaluated the completed installation documents (WO IP3-03-16437) to ensure the alteration was installed in accordance with the design and procedure requirements.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan (EP) Changes

a. Inspection Scope (71114.04)

During an in-office inspection from May 19 - 20, 2003, regional inspectors reviewed recent changes to EP-related documents as stated in the attachment to this report. A detailed review was conducted of aspects of the plan related to the risk-significant planning standards (RSPS), such as classifications, notifications and protective action recommendations. A general review was also conducted for non-RSPS portions. These changes were reviewed against 10 CFR 50.54(q) to ensure that the changes did not decrease the effectiveness of the plan, and that the changes could continue to meet the standards of 10 CFR 50.47(b) and the requirements of Part 50, Appendix E. All of the changes made to the emergency plan or implementing procedures are subject to future inspections to ensure that the results of the changes continue to meet NRC regulations.

c. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control To Radiologically Significant Areas

a. Inspection Scope (71121.01)

The inspectors reviewed radiological work activities and practices, and procedure implementation during tours and observations of the facilities; and inspected procedures, records, and other program documents to evaluate the effectiveness of Entergy's access controls to radiologically significant areas.

On May 22, 2003, the inspectors toured and observed work activities in the primary auxiliary, fuel storage, and radioactive waste handling (RAMS) buildings. During these walkdowns, the inspectors observed and verified the appropriateness of the posting, labeling, and barricading of radioactive material, radiation, contamination, high radiation, and locked high radiation areas. At the routine radiologically controlled area (RCA) access control point, the inspectors observed radiation workers logging into the RCA on radiological work permits (RWPs) using electronic dosimeters and observed radiation workers exiting the RCA and then logging out of their RWPs. The inspectors examined the use of personnel dosimetry and the radiological briefings for radiation workers entering the RCA. On May 20 and 22, the inspectors observed pre-job briefings for IP3 containment entries at power using RWP No. 033028. The pre-job briefings covered radiation safety, confined space, and heat stress considerations associated with the work evolutions.

The inspectors performed a selective examination of procedures, records, and other program documents (see List of Documents Reviewed section) to evaluate the adequacy of radiological controls.

The criteria for the review in this area were contained in: Title 10 of the Code of Federal Regulations (CFR) Part 19 (Notices, instructions, and reports to workers; inspection and investigations) and Part 20 (Standards for protection against radiation), including Subparts B, C, D, F, G, H, I, J, K, L, and M, site Technical Specifications, and site procedures.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Control

a. Inspection Scope (71121.02)

The inspectors reviewed the effectiveness of the licensee's program to maintain occupational radiation exposure as low as is reasonably achievable (ALARA). The inspectors discussed with the Indian Point Energy Center (IPEC) Radiation Protection Manager the actual versus projected cumulative year-to-date dose results for 2003, which included the recent refueling outage (3R12). The inspectors also met with the radiological engineer who coordinated the ALARA planning for the recent refueling outage (3R12) at IP3 and with several radiological engineers who had performed post-job ALARA reviews for outage RWPs. The inspectors selectively reviewed and discussed the available post-job ALARA reviews; and selectively examined procedures, records, and other program documents for regulatory compliance and for the adequacy of controls over radiation exposure (see List of Documents Reviewed section).

The criteria for this review were contained in 10CFR20.1101 (Radiation protection programs), 10CFR20.1701 (Use of process or other engineering controls), and in site procedures.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation

a. Inspection Scope (71121.03)

The inspectors reviewed the program for health physics instrumentation and for installed radiation monitors to determine the accuracy and operability of the instrumentation. During the plant tours described in Section 2OS1 of this report, the inspectors reviewed field instrumentation utilized by health physics technicians and plant workers to measure radioactivity and radiation levels. The reviewed instruments included: portable field survey instruments, hand-held contamination frisking instruments, continuous air monitors, whole body friskers, and portal monitors. The inspectors verified current calibration, source checking, and proper instrument function. Also during plant tours, the inspectors identified and noted the condition, operability, and calibration status of selected installed area and process radiation monitors and any accessible local indication information for those monitors. The inspectors examined the calibration and functionality test records for selected installed radiation monitors (see the List of Documents Reviewed section).

On May 21, the inspectors met with the cognizant radiological engineer to discuss the corrective actions for the issue identified in CR-IP3-2002-02372. The issue involved the need to periodically evaluate and document the impact that difficult-to-detect radionuclides have on the detection capabilities and limits of the contamination monitoring instrumentation in use. The inspectors reviewed selected use/calibration procedures; and performed a selective examination of procedures, records, and other program documents for adequacy and regulatory compliance (see the List of Documents Reviewed section). The criteria for this review was contained in 10CFR20.1501, 10CFR20, Subpart H, site Technical Specifications, and site procedures.

b. Findings

No findings of significance were identified.

4. SAFEGUARDS

Cornerstone: Physical Protection [PP]

3PP4 Security Plan Changes

a. Inspection Scope (711130.04)

Regional security inspectors performed an in-office review of changes to the IP3 Security, Contingency, and Training and Qualification Plans. The specific revisions reviewed were: revision 20 thru 23 of the Security Plan, revision 6 of the Contingency Plan, and revision 9 of the Training and Qualification Plan. There was also a review conducted of the combined Unit 2 and Unit 3 Training and Qualification Plan identified as revision 0. These revisions were submitted to the NRC between March 2001 and January 2002 in accordance with the provisions of 10CFR50.54(p). The review was conducted to confirm that the changes were made in accordance with 10CFR50.54(p) and did not decrease the effectiveness of the plans. The NRC recognizes that some requirements contained in these program plans have been superceded by the February 2001 Interim Compensatory Measures Order.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator Verification

a. Inspection Scope (71151)

The inspectors reviewed the licensee's data submitted to the NRC for the following performance indicators (PIs), and performed an independent verification that the source data was consistent with plant records.

The inspector reviewed the licensee's performance indicator (PI) data collecting and reporting process as described in procedure SAO-114, "Preparation of NRC and WANO Performance Indicators." The purpose of the review was to determine whether the methods for reporting PI data are consistent with the guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guidelines," Revisions 1 and 2. The inspection included a review of the indicator definitions, data reporting elements, calculation methods, definition of terms, and clarifying notes for the performance indicators. Plant records and data were sampled and compared to the reported data. The inspector reviewed the licensee's actions to address and satisfactorily resolve discrepancies in the performance indicator data.

.1 Reactor Coolant System Specific Activity

The inspectors reviewed the PI for reactor coolant system (RCS) specific activity for the period from January 2002 - March 2003. The RCS specific activity PI is reported as a percentage of the maximum Technical Specification limit for dose equivalent iodine-131 in micro-Curies per cubic centimeter. For the period reviewed, this PI remained in the Green band. The inspectors reviewed monthly average RCS sample results based upon daily samples obtained in accordance with procedure SOP-SS-001, "Operation of the Primary Sampling System," Rev 14. The inspectors also observed a daily RCS sample taken on May 14, 2003. The inspectors compared the PI data against the guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline."

.2 Scrams With Loss of Normal Heat Removal and Unplanned Scrams Per 7,000 Critical Hours

The inspectors reviewed the PIs for scrams with loss of normal heat removal (LNHR) and unplanned scrams per 7,000 critical hours for the period from January 2002 - March 2003. The PI for scrams with LNHR monitors the number of unplanned scrams while critical, during the previous 12 quarters, that involved a loss of the normal heat removal path through the main condenser. The unplanned scrams per 7000 critical hours PI monitors the rate of unplanned automatic and manual reactor scrams per year, based upon the number of hours of power operations, and is a measure of initiating events frequency. The inspectors reviewed operator logs, licensee event reports, and monthly operating reports to compare PI data reported by the licensee. The inspectors compared the PI data against the guidance contained in NEI 99-02. (This PI data review was completed prior to the unplanned scram on June 22, 2003).

.3 Safety System Unavailability - Auxiliary Feedwater

The inspectors reviewed Entergy's PI data for the AFW Safety System Unavailability to verify that the PI data was accurate and complete. The inspectors compared the PI data reported by the licensee to information gathered from the control room logs, condition reports, and work orders for the 1st, 2nd, 3rd, and 4th quarters of 2002. In addition, the inspectors interviewed the system engineers, and compared the PI data against the guidance contained in NEI 99-02.

b. Findings

No findings of significance were identified

4OA2 Identification and Resolution of Problems

a. Inspection Scope (71152)

The inspectors evaluated the licensee's corrective actions to ensure that they were appropriately focused to correct the identified problems. The procedures were reviewed to verify that appropriate changes had been made to properly implement the prescribed corrective actions. The inspectors also evaluated the changes for technical adequacy.

.1 Condition Report IP3-2002-0671: This condition report addressed an inadequate risk assessment and was previously described in NRC inspection report No. 50-286/02-02.

On March 4, 2002, the licensee scheduled the simultaneous performance of safety injection system surveillance tests 3PT-M14B, "Safety Injection System Logic Functional Train B," and 3PT-Q116A, "31 Safety Injection Pump Functional." Prior to performing the tests, the inspector and responsible system engineer raised the concern that simultaneous performance of these tests would render both trains of the safety injection system inoperable and the tests were not performed concurrently. Initial inspector review of the available risk assessment tools identified that the software programs being used did not recognize this test performance vulnerability and the more restrictive TS LCO condition that would result.

On July 8, 2002, the licensee issued station directive SPO-SD-06, "On-Line Risk Assessment Process," that provided improved guidance to the work control organization for performing on-line risk assessments for the 12-week rolling schedule. The procedure contained detailed instructions for completing Operations Impact Reviews and for incorporating the results of probabilistic risk assessment results into the daily work schedules. The inspectors reviewed the licensee's computer program (ORAM-Sentinel, "All Modes Maintenance and Safety Function Advisor") for planning and evaluating operational risk, based upon proposed plant specific configurations (various combinations of equipment out of service). The licensee demonstrated to the inspectors that the ORAM-Sentinel program generated an unacceptable “Red” (very high risk) condition when both the 3PT-M14B and 3PT-Q116A surveillances were scheduled simultaneously, and would prevent that condition from being entered into the 12-week schedule. The licensee also demonstrated that inputs of other combinations of safety-related equipment out of service into the ORAM-Sentinel program would have been prevented.

.2 The inspectors reviewed the tracking system used by the Inservice Inspection (ISI) group to manage critical elements of the ISI program, such as procedure compliance, personnel qualification, and calibration of equipment. The inspectors reviewed the corrective actions and determined that the licensee was identifying problems at an appropriate threshold and entering them into the corrective action program. For problems documented by the licensee, corrective actions were appropriate.

.3 The Occupational Radiation Safety specialist inspection included a review of the following documents identified in the corrective action program for the appropriateness and adequacy of event categorization, immediate corrective action, corrective action to prevent recurrence, and timeliness of corrective action: Condition Reports CR-IP3-2002-02372 and CR-IP3-2003-02443, -02499, and -02506.

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up

a. Inspection Scope (71153)

.1 On April 28, Indian Point Energy Center experienced two electrical grid disturbances. This was documented in CR-IP3-2003-02790. The electrical perturbations resulted in multiple alarms and plant equipment problems, including: a trip of 32 rod drive motor-generator and CCR air conditioner compressors; an auto start of 32 CCW pump; the automatic transfer of the 33 inverter to its alternate power supply; the 32 main transformer auxiliaries transferred to emergency power; and the traveling water screen wash pumps tripped. The inspectors evaluated the aggregate effects that these equipment problems and realignments had on mitigating systems and overall plant safety.

Following the transient, the inspectors analyzed system data to assess the plant’s response and concluded that all systems responded within their design limits. The inspectors evaluated the apparent cause of the transient and subsequent anomalies, and reviewed condition reports initiated by the licensee to document problems associated with the transient.

.2 Main Turbine Fire

At approximately 3:00 a.m. on April 29, 2003, with the reactor at 59% power, plant operators detected smoke on the 53-foot elevation of the turbine building, and reported a fire under the south end of the main high pressure turbine near the No. 2 bearing. Control room operators immediately tripped both the main turbine and the reactor. The fire brigade responded and was able to extinguish the fire by 3:50 a.m. using a fire water hose with foam. No offsite assistance was necessary or required by fire program procedures. Early attempts to extinguish the fire with portable CO_2 and the installed CO_2 system were not successful. At the time of the fire, the reactor and turbine were in a power ascension following refueling outage 3R12. Since the duration of the fire was greater than 15 minutes, the licensee declared a Notice of Unusual Event (NUE) at 3:13 a.m. in accordance with their procedure (CR-IP3-2003-2795).

The licensee notified the resident inspectors, who responded to the site to monitor the licensee's actions following this event. The inspectors reviewed the post-trip response of the plant and observed operator actions in the control room to initiate normal decay heat removal using the auxiliary feedwater system and the main condenser steam dumps. Operators maintained the reactor stable in Mode 3 following the trip, while the damaged insulation was removed to investigate the cause of the fire.

The licensee determined that the fire was caused from oil saturated insulation around the main turbine No. 2 bearing. The oil originated from an improperly installed cover plate on the casing around the bearing and saturated the insulation around the outside of the turbine below the bearing. The only damage resulting from the fire was to the insulation itself. There were no personnel injuries associated with the event. The NUE was terminated at 5:20 a.m. after the licensee determined that the fire was completely extinguished and there was no risk of re-ignition.

.3 On June 22, 2003, the reactor automatically tripped following the failure of 345KV output breaker No. 3. The breaker had been opened earlier in the day to support maintenance on the distribution network (345KV line W98). The failure occurred when the licensee attempted to shut the breaker after the maintenance was completed. The failure was due to a phase to ground fault on the "B" phase of the breaker. This failure was similar to a previous event which resulted in a plant trip on November 15, 2002, involving a phase to ground fault of the "B" phase of breaker No. 3. The inspector notes that the breaker was completely overhauled after the November failure before being returned to service.

Shortly after the trip, the licensee formed a post-trip review group (PTRG), which conducted interviews with the operators and analyzed plant system data to assess the plant's response. The inspectors reviewed PTRG Report No. 03-04, which indicated that all systems responded within their design limits. The inspectors evaluated the PTRG recommended actions prior to restart to ensure they adequately addressed the initiating cause of the trip and subsequent anomalies. The inspectors also reviewed the condition report initiated by the licensee to document problems associated with the trip (CR-IP3-2003-3809).

On June 27, a representative of the breaker's manufacturer performed an investigation on the internals of all three phases of breaker No. 3. The vendor's initial conclusion was that water intrusion into the "B" phase caused the failure. However, at the end of the inspection period, the licensee was continuing an in-depth root cause investigation to determine the exact cause and failure mechanism, and was investigating other potential failure mechanisms.

Prior to the reactor trip, the licensee's Performance Indicator (PI) for unplanned scrams was Green (i.e., at 2.8 scrams within 7000 critical hours). However, following the reactor trip, the PI increased to 3.8 scrams within 7000 critical hours which caused the PI to exceed the White threshold (3.0). As a result, the NRC will conduct a 95001 supplemental inspection to review the causes related to the White PI in accordance with IMC 2515.

.4 Licensee Event Report Reviews

(Closed) LER 2003-002-00; By letter dated June 25, 2003, the licensee submitted LER No. 2003-002-00 to report a manual turbine/reactor trip and Notice of Unusual Event (NUE) which occurred on April 29, 2003 (CR-IP3-2003-2795). Plant operators tripped the turbine after discovering a fire in the insulation surrounding the main high pressure turbine that resulted from an oil leak in a cover plate on a turbine bearing casing. The details of the LER were reviewed by the inspectors and the details of the event are described in Section 4OA3 of this report. Based on this review and inspector observations immediately following the event, this LER is closed.

b. Findings

Introduction. On April 29, 2003, a self-revealing Green finding was identified involving poor maintenance practices and inadequate work controls during main turbine bearing inspections which contributed to the improper reinstallation of the No. 2 bearing casing and an oil leak which caused a fire.

Description. The No. 2 turbine high pressure bearing was disassembled for inspection during the refueling outage and not properly reassembled by a contractor. As a result, an oil leak progressed over a couple of days and on April 29, the surrounding oil soaked lagging ignited due to the high temperature of the steam turbine casing. Prior to extinguishing the fire, control room operators manually tripped the turbine and reactor.

Analysis. A turbine and reactor trip resulted from deficiencies in work control that failed to properly restore a cover plate on the No. 2 bearing of the high pressure turbine. This finding was greater than minor since it was associated with the Protection Against External Factors and the Human Performance attributes that affect Initiating Events cornerstone objective; and since maintenance work control inadequacies resulted in a perturbation in plant stability by causing a reactor trip. The finding is of very low safety significance (Green) as determined using the SDP Phase 1 worksheet. Specifically, the event did not increase the likelihood of a primary or secondary system loss of coolant accident initiator, did not contribute to a loss of mitigation equipment functions, and did not increase the likelihood of an internal/external flood. **(FIN 50-286/03-06-04)**.

Enforcement

No violation of regulatory requirements occurred.

4OA4 Human Performance During The 12th Refueling Outage

2. Inspection Scope (71111.20)

During the refueling outage the inspectors reviewed and evaluated a number of events documented in condition reports that involved human performance errors.

3. Findings

Four findings of very low safety significance were identified or self-revealing during this inspection period which had human performance errors as either direct or related causal factors. Two of these findings involved errors during the performance of maintenance (i.e., inadequate re-installation of a turbine bearing cover plate and inadequate installation of a SG bowl drain line plug). The other two findings involved configuration control errors during shutdown operations involving the inadequate verification of the status of an operating spent fuel pool cooling pump and the running of a safety injection pump with no flow due to an improper valve line-up. During the outage, the inspectors noted an number of other minor events with human performance aspects.

- Inadequate Work Control / Work Practices (CR-IP3-2003-1912, 2003-2045, 2003-1623, 2003-1639, 2003-1664, 2003-1668, 2003-1838, 2003-1842, 2003-1919, 2003-1921, 2003-2114, and 2003-2035)
- Operator Error (CR-IP3-2003-1710)

The inspectors evaluated these events in the aggregate and discussed their observations with site senior management. No further action was taken.

4OA6 Meetings

Exit Meeting Summary

On July 16, 2003, the inspectors presented the inspection results to Mr. Chris Schwarz and Entergy staff members who acknowledged the inspection results presented. The inspectors verified with Entergy personnel that no materials evaluated during the inspection were considered proprietary.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

W. Axelson	Support Supervisor
S. Baer	HP Supervisor
J. Boccio	I&C Supervisor
R. Cavalieri	Site Planning and Outage Services Manager
R. Christman	Assistant Operations Manager, Operations Staff
J. Comiotes	Director, Nuclear Safety Assurance
F. Dacimo	Site Vice President
M. Dampf	Health Physics Manager
J. DeRoy	Director of Engineering
R. Deschamps	Radiation Protection Superintendent
M. Devlin	Work Control Superintendent
R. Discensi	Technical Support Manager
J. Donnelly	Corrective Actions and Assessment Manager
J. Kelly	Director, Nuclear Safety Assurance
B. Kyler	HP Supervisor
J. McCann	Licensing Manager
R. Milici	Senior Electrical Engineer
E. O'Donnell	IP3 Operations Manager
R. Penny	Manager, Engineering Programs
J. Perrotta	Quality Assurance Manager
S. Petrosi	Design Engineering, Manager
P. Rubin	IPEC Operations Manager
C. Schwarz	General Manager, Plant Operations
M. Smith	Director, Engineering Projects
R. Solanto	HP Supervisor
J. Stewart	HP Supervisor
D. Thompson	Security Manager
A. Vitale	Maintenance Manager
J. Wheeler	Training Manager
R. Decensi	Technical Support Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Closed

LER 2003-002-00	Manual reactor trip on April 29, 2003, due to a fire on the main high pressure turbine as a result of a bearing oil leak (Section 4OA3).

Opened and Closed

NCV 50-286/03-06-01	Operation of the 32 SI pump at zero flow for longer than the manufacturer's limit to prevent damage (Section 1R15)
NCV 50-286/03-06-02	Loss of reactor coolant system (RCS) inventory during fuel transfer due to inadequate procedure implementation to install a steam generator bowl drain plug (Section 1R20).
FIN 50-286/03-06-03	Loss of primary spent fuel pool cooling (Section 1R15).
FIN 50-286/03-06-04	Main Turbine Fire and Notice of Unusual Event (NUE) (Section 4OA3).

LIST OF DOCUMENTS REVIEWED

Section 1R08, Inservice Inspection

INT-3-3413, Rev 2
INT-3-3414, Rev 2
INT-3-4190, Rev 2
INT-3-3601, Rev 2
INT- 2-2547, Rev 1
INT-2-2546, Rev 6
INT-1-3101-31-1
Calibration Data Sheet 1-3101-33
Work Order IP3-03-18062, UT OF SG 33 & 34 Primary Nozzles
CR-IP3-2003-01614
CR-IP3-2003-02166

References

[1] Westinghouse Indication Data Sketch INT-1-1300, Rev. 4, dated 4/12/2003.
[2] Letter Report HLG-03-006/SIR-03-047, Rev.1, from Structural Integrity Associates, Inc. to Entergy Nuclear Northeast, "Disposition of Indication Found in the Indian Point 3 Closure Head," April 14, 2003.

Section 1EP4, Emergency Preparedness

Indian Point Energy Center Emergency Plan, Rev 03-01
IP-EP-115, Emergency Plan Forms, Rev 1, 2
IP-EP-130, Emergency Notifications and Mobilization, Rev 0
IP-EP-250, Emergency Operations Facility, Rev 0
IP-EP-251, Alternate Emergency Operations Facility, Rev 1
IP-EP-255, Emergency Operations Facility Management and Liaisons, Void
IP-EP-260, Joint News Center, Rev 0

IP-EP-310, Dose Assessment, Rev 1
IP-EP-410, Protective Action Recommendations, Rev 1
IP-EP-510, Meteorological, Radiological & Plant Data Acquisition System, Rev 1
IP-EP-520, Modular Emergency Assessment & Notification System (MEANS), Rev 1
IP-EP-610, Emergency Termination and Recovery, Rev 1
IP-EP-620, Estimation of Total Population Exposure, Rev 1
IP-1002, Emergency Notification and Communication, Rev 29, Void (IP2)
IP-1010, Central Control Room, Rev 9, 10 (IP2)
IP-1011, Joint News, Void (IP2)
IP-1015, Radiological Monitoring Outside the Protected Area, Rev 11 (IP2)
IP-1019, Coordination of Corporate Response, Void (IP2)
IP-1030, Emergency Operations Facility, Void (IP2)
IP-1038, Offsite Emergency Notifications, Void (IP3)
IP-2001, ED, POM, Shift Managers Procedure, Rev 18 (IP3)
IP-2005, CR Offsite Communicator, Void (IP3)
IP-2300, Emergency Activation of the Emergency Operations Facility, Void (IP3)
IP-2302, EOF Technical Advisor & Information Liaison, Void (IP3)
IP-2303, EOF Radiological Assessment Team Leader, Void (IP3)
IP-2304, EOF Dose Assessment Health Physicist, Void (IP3)
IP-2305, EOF Midas Operator, Void, (IP3)
IP-2306, EOF Security Officer, Void (IP3)
IP-2307, EOF Clerk, Void (IP3)
IP-2308, EOF Direct Line Communicator, Void (IP3)
IP-2309, EOF Offsite Communicator, Void (IP3)
IP-2310, EOF Onsite Radiological Communicator, Void (IP3)
IP-2311, EOF Offsite Radiological Communicator, Void (IP3)

Section 2OS1, Access Control to Radiologically Significant Areas:

RE-ACC-5-3, Rev. 3, Replaced steam generator storage facility survey
RE-ADM-1-7, Rev. 8, Health physics access key control
RE-REA-4-1, Rev. 20, Radiation work permit (RWP)
RWP 033028, Rev. 17, Containment entry/reactor critical/outside crane wall
Personnel contamination log for the refueling outage (3RFO12)
Analysis of personnel contaminations during IP3 RFO 12, March 28 to April 25, 2003
Self-assessment of Technical Support Integration

Section 2OS2, ALARA Planning and Controls:

RE-ALA-2-3, Rev. 7, Temporary shielding control
RE-REA-4-1, Rev. 20, Radiation work permit (RWP)
ALARA post-job review (outage 3RO12) tracking sheet
ALARA post-job review 03-412 for RWP No. 033412, Rev. 5, Radiography in RCA
ALARA post-job review 03-413 for RWP No. 033413, Rev. 5, ALARA shielding
ALARA post-job review 03-417 for RWP No. 033417, Rev. 0, Fuel transfer canal upgrade
ALARA post-job review 03-424 for RWP No. 033424, Rev. 0, Filters for reactor cavity and 46-foot drain down area

ALARA post-job review 03-428 for RWP No. 033428, Rev. 0, Reactor cavity decontamination
ALARA post-job review 03-429 for RWP No. 033429, Rev. 2, Steam generator 31 - 34 primary side work
ALARA post-job review 03-430 for RWP No. 033430, Rev. 3, Steam generator secondary side work
ALARA post-job review 03-434 for RWP No. 033434, Rev. 0, Reactor head/bare metal inspection
ALARA post-job review 03-435 for RWP No. 033435, Rev. 0, Reactor head/alloy 600 inspection
ALARA critique for 3R12 by Radiation Protection
IP3 daily ALARA information for May 18, 2003

Section 2OS3, Radiation Monitoring Instrumentation and Protective Equipment:

RE-CON-3-4, Rev. 11, Release of material from the radiologically controlled area
RE-INS-7CA-14, Rev. 6, Calibration of Ludlum 177 and Eberline RM-14 friskers
RE-INS-7CA-17, Rev. 8, Frisker probe efficiency check
RE-INS-7CE-5, Rev. 2, Calibration of the N.E. contamination monitor CM11 with DP11A probe
RE-INS-7CE-6, Rev. 10, Calibration of the N.E. IPM-7/8 installed personnel monitor
RE-INS-7CE-7, Rev. 7, Calibration of the N.E. monitor CM7A with DP5HA probe
RE-INS-7CE-8, Rev. 8, Calibration of the N.N.C. gamma-60 portal radiation monitors
RE-INS-7CE-9, Rev. 3, Calibration of the SAM-9 small articles monitor
RE-INS-7CF-13, Rev. 2, Calibration of the Eberline SAM-2 with HP-210 probe
RE-INS-7CE-14, Rev. 2, Calibration of the Eberline MS-2 with HP-210 probe
RE-SUR-6-2, Rev. 11, Contamination surveys, posting, and assessment
Test results for IC-RMP-R-1-F, Rev. 3, Functional test of radiation monitor R-1, performed during March 2003
Test results for IC-RMP-R-2/17B-F, Rev. 1, Functional test of radiation monitors R-2, 4, 6, 7, 8, 17A, and 17B, performed during January 2003
Calibration results for 3 PC-R44F, Rev. 6, Area radiation monitor calibration (RM-69), performed during May 1999
Calibration results for 3 PC-R46B, Rev. 10, Containment high range radiation monitor calibration (R-26), performed during April 2003
Calibration results for 3 PC-R46A, Rev. 11, Containment high range radiation monitor calibration (R-25), performed during April 2003
Health physics continuing training lesson plan, LP No. HCT0301.01, Instrumentation sensitivity and contamination control, Rev. 0

LIST OF ACRONYMS

3R12	Indian Point 3 refueling outage no. 12
A/C	air conditioning
ADV	atmospheric dump valve
AFW	auxiliary feed water
ALARA	as low as reasonably achievable
AP	administrative procedure
ASME	Association of Mechanical Engeineers
CAP	Corrective Action Program
CCR	central control room
CFR	Code of Federal Regulations
COL	check-off list
CR	condition report
CY	Calender Year
EDG	emergency diesel generator
EHC	electro-hydraulic control
EOF	Emergency Operations Facility
EOP	Emergency Operating Procedure
EP	Emergency Plan
FP	fire protection
SG	steam generator
HDP	heater drain pump
HP	Health Physics
IAC	instrument air compressor
I&C	Instrument and Control
ICMs	Interim Compensatory Measures
IMC	Inspection Manual Chapter
IP2	Indian Point 2
IP3	Indian Point 3
IPEC	Indian Point Energy Center
KV	kilo volts
LNHR	loss of normal heat removal
LOCA	Loss of Coolant Accident
MOV	motor-operated valve
NCV	Non-cited Violation
NEI	Nuclear Energy Institute
NI	nuclear instrument
NRC	Nuclear Regulatory Commission
NUE	notice of an unusual event
OD	operability determination
ONOP	off-normal operating procedure
OS	Occupational Radiation Safety
PAB	primary auxiliary building
PFP	Pre-Fire Plan
PI	performance indicator
PM	preventive maintenance
PMT	post-maintenance test
PRNI	power range nuclear instrument
PTRG	Post Transient Review Group
QA	Quality Assurance

RCA	Radiologically Controlled Area
RCP	reactor coolant pump
RCS	reactor coolant system
RHR	residual heat removal
RSPS	Risk Significant Planning Standards
RWP	Radiation Work Permit
SDP	significance determination process
SFP	spent fuel pool
SG	steam generator
SI	safety injection
SOP	system operating procedure
SSC	structures, systems, and components
SW	service water
TA	temporary alteration
THCC	turbine hall closed cooling
TI	Temporary Instruction
TM	temporary modification
TS	Technical Specifications
URI	Unresolved Item
VC	vapor containment
WO	work order