November 10, 2003

Mr. Fred R. Dacimo
Site Vice President
Entergy Nuclear Northeast
Indian Point Energy Center
295 Broadway, Suite 1
P.O. Box 249
Buchanan, NY 10511-0249

**SUBJECT: INDIAN POINT 3 NUCLEAR GENERATING UNIT 3 - NRC INTEGRATED INSPECTION REPORT 05000286/2003008**

Dear Mr. Dacimo

On September 27, 2003, the US Nuclear Regulatory Commission (NRC) completed an inspection at the Indian Point Nuclear Generating Unit 3 (Indian Point 3). The enclosed integrated inspection report documents the inspection findings, which were discussed on October 8, 2003, with Mr. John Ventosa and other members of your staff.

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

Based on the results of the inspection, the inspectors identified three findings of very low safety significance (Green). Two of the findings were determined to be violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these two findings as non-cited violations (NCVs) consistent with Section VI.A.I 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; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement; and the NRC Resident Inspector at Indian Point 3.

Since the terrorist attacks on September 11, 2001, the 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 2002 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/

David C. Lew, Chief
Projects Branch 2
Division of Reactor Projects

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

Enclosure: Inspection Report 05000286/2003008
w/Attachment A: Supplemental Information and
Attachment B: TI 2515/150 Reporting Requirements

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REGION I

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|---|---|
| Docket No. | 50-286 |
| License No. | DPR-64 |
| Report No. | 05000286/2003008 |
| Licensee: | Entergy Nuclear Northeast |
| Facility: | Indian Point Nuclear Generating Unit 3 |
| Location: | Buchanan, NY |
| Dates: | June 29, 2003 - September 27, 2003 |
| Inspectors: | P. Drysdale, Senior Resident Inspector<br>R. Berryman, Resident Inspector<br>P. Habighorst, Senior Resident Inspector<br>M. Cox, Resident Inspector<br>L. James, Resident Inspector<br>W. Cook, Senior Project Engineer<br>T. Jackson, Project Engineer<br>T. Fish, Senior Operations Engineer<br>D. Jackson, Operations Engineer<br>J. D'Antonio, Operations Engineer<br>J. Schoppy, Senior Reactor Inspector<br>J. McFadden, Radiation Specialist<br>F. Jaxheimer, Reactor Inspector<br>J. Laughlin, Reactor Inspector |
| Approved by: | David C. Lew, Chief<br>Projects Branch 2<br>Division of Reactor Projects |

CONTENTS

## SUMMARY OF FINDINGS

IR 05000286/2003-008, 06/29/2003 - 09/27/2003, Indian Point Nuclear Generating Unit 3. Maintenance Effectiveness; Personal Performance During Non-Routine Plant Evolutions and Events; Operability Evaluations.

The report covers a three month period of inspection by resident inspectors, regional operations and project engineers, a reactor inspector, and a radiation specialist. Two Green non-cited violations and one Green finding were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process," (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process" Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. This self-revealing finding involved the failure of Entergy to ensure that nitrogen regulating valve IA-PCV-1276, which is a back-up to the instrument air supplying the auxiliary feedwater regulating valves, is capable of performing its design function. On August 14, 2003, the lack of nitrogen pressure back-up to the instrument air system caused the auxiliary feedwater regulating valves to fail open and resulted in a challenge to plant operators to maintain proper steam generator levels.

  This finding is greater than minor because it affected the Mitigating Systems Cornerstone objective of equipment availability and reliability, in that the failure of the auxiliary feedwater regulating valves to the fully opened position removed one of the means of run-out protection to the motor driven auxiliary feedwater pumps. This finding is of very low safety significance since the auxiliary feedwater pumps were still capable of performing their design function (Section 1R12).

- Green. The inspector identified a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," involving the failure of Entergy to promptly diagnose and correct an electrical ground on the 33 125 VDC system.

  The finding is greater than minor because it affects the objective of the Mitigating Systems Cornerstone to ensure the reliability and capability of critical safety equipment (125 VDC station battery and emergency diesel generator) performance, in that an unevaluated locked-in ground can potentially impact equipment functionality. The finding is of very low safety significance since the 33 125 VDC system and affected 31 emergency diesel generator were capable of performing their design functions. (Section 1R14).

- Green. The inspectors identified a non-cited violation of 10CFR50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," involving the failure of Entergy to adhere to a quarterly surveillance procedure on August 4, 2003, and initiate actions required by Technical Specification (TS) 3.8.6 for the inoperable 31 station battery due to a low individual cell (No. 26) voltage.

This finding is greater than minor because subsequent evaluation determined that the safety-related 31 station battery was adversely affected, and if left uncorrected, this condition could have resulted in a more significant safety concern (i.e., cell reversal) and loss of battery function. The safety significance of this finding is very low because of the low probability that the single degraded cell would have resulted in a cell reversal and placed an additional load on the battery that would have been sufficient to reduce overall battery capacity below its design basis loading specification. (Section 1R15).

B. Licensee Identified Violations

None

## REPORT DETAILS

Summary of Plant Status

The unit began the inspection period at 100% power.

On August 14, 2003, the reactor automatically tripped from 100% power following a complete loss of offsite power due to the Northeast grid blackout. The plant remained in hot shutdown (mode 3) until August 16, when problems with fuses and cable splices in the control rod drive mechanism (CRDM) power supplies prevented normal rod withdrawal for a plant startup. On August 17, the reactor was taken to cold shutdown in order to inspect and replace several CRDM cable splices and rod control fuses. Following satisfactory repairs and CRDM testing, a plant heatup commenced on August 20, and the reactor achieved criticality on August 21. The plant returned online on August 22, and achieved full power on August 23. The plant remained at 100% power for the remainder of the inspection period.

1. **REACTOR SAFETY**

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

1R01 Adverse Weather Protection

a. Inspection Scope (71111.01)

- The inspectors reviewed plant equipment performance during the Summer months to verify that adequate design and operating margins were maintained during the seasonally higher temperatures.

  On July 22, 25 and 29, 2003, the inspectors reviewed the appropriateness of the licensee's response to numerous high temperature alarms on the main turbine generator stator coolers. The inspectors also observed non-essential service water (SW) inlet and outlet temperatures and the licensee's SW flow measurements to evaluate the extent of these conditions. The inspectors also reviewed the licensee's response to the out-of-specification temperature of the condensate storage tank (CST) that occurred during several hot periods in July. The inspectors verified that the CST temperature did not exceed the licensee's administrative limit which is five degrees below the maximum allowed in the plant's design basis (100F).

- During September 15 - 19, 2003, the inspectors reviewed the licensee's severe weather preparation procedures and the Action Plan developed to prepare the Indian Point site for Hurricane Isabel. The plan included projected staffing requirements for the emergency response organization (ERO), a prohibition on all switchyard work, a rescheduling of site activities to minimize work that could impact preparedness, the identification of contingency plans for potential flooding, and the delivery of fuel oil to maximize quantities available for the emergency diesel generators (EDGs) and other diesels on site. The inspectors also performed internal and external plant walkdowns to assess the adequacy of those preparations. The inspectors verified that the licensee appropriately addressed loose objects that were identified by the inspectors, which were not secured or removed. The licensee issued condition report CR-IP3-2003-05138 to address these items.

The inspectors reviewed the licensee's documented risk assessment and the planned work schedule for the week of September 15 to determine the potential for increased risk in the event that Hurricane Isabel passed close enough to the site to have a direct impact on plant operation. The inspectors also reviewed the licensee's detailed risk assessment for removing portions of the isolation valve seal water system from service during the projected storm to ensure that the increase in risk did not exceed the licensee's administrative limits on peak core damage frequency (CDF).

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope (71111.04Q)

The inspectors performed partial system walkdowns during periods 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 that the licensee had identified equipment discrepancies that could potentially impair the functional capability of the available train.

- During July 17 - 18, 2003, the inspectors performed a partial system alignment check of the EDG fuel oil transfer system to verify operability and fuel supply to all EDGs while the 31 fuel oil transfer system was out of service for planned maintenance. The inspectors used the clearance (3C13-3EG) specified in work order package IP3-03-03882, and System Operating Procedure SOP-EL-001, "Diesel Generator Operation," to verify the proper equipment alignment, and to identify discrepancies that could impair the function of the EDGs or that could potentially increase plant risk.

- During July 24 - 25, 2003, the inspectors performed a partial system alignment check of the 31 residual heat removal (RHR) pump train to verify operability while the 32 pump was out of service for planned preventive maintenance. The inspectors used check-off list COL-RHR-1, "Residual Heat Removal System," and System Operating Procedure 3-SOP-RHR-001, "Residual Heat Removal System," to verify the proper train alignment, and to identify discrepancies that could impact the function of the available train or that could potentially increase plant risk.

- During September 24 - 25, 2003, the inspectors reviewed Clearance 3C13 3-AFW-BFD-406A MMEC and performed a partial system alignment of the auxiliary feedwater (AFW) system to verify operability and proper restoration of the system following completion of planned maintenance on the 31 auxiliary boiler feedwater pump (ABFP) and its regulating flow valve BFD-406A to the 31 steam generator (SG).

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope (71111.05Q)

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.” These tours were conducted to ensure that ignition sources were controlled in accordance with FP-8, “Controlling of Ignition Sources”; to ensure that fire protection equipment specified in the Pre-Fire Plans (PFPs) was available and functional; 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 Zone 23: AFW pump room on the 18-foot elevation of the AFW pump building (PFP-47, “AFW Pump Room - Auxiliary Feedwater Building”).

- Fire Zones 23A, 25A, 27A, 28A, 30A, 31A, 89A: Filter rooms, heat exchangers, boric acid tank area (excluding high radiation areas) on the 72' elevation of the primary auxiliary building (PAB), (PFP-13, “Primary Auxiliary Building - Elevation 72'-0"”).

- Fire Zones 14, 66A, 67A: 480 VAC Switchgear Rm, 15' Control Bldg.; the unit auxiliary transformer (UAT); and the station auxiliary transformer (SAT); (PFP-25, “480V Switchgear Room - Control Building,” and PFP-62, “Main Transformer Yard”). The inspectors observed the physical condition of the deluge system for the UAT and SAT. The inspectors also evaluated the transformer oil cooling systems for leakage and observed the general area for combustible material loading.

- Zones 5A, 62A, 68A: 35'-0", 32'-6" elevations of PAB Pipe Tunnels (PFP-6A, “Mini Containment and Pipe Tunnels - PAB/Fan House”). The inspectors also reviewed Fire Barrier Analysis IP3-ANAL-FP-00756 for fire barriers in these areas.

- Fire Zones 10, 36A, 101A, and 102A: 31, 32, and 33 EDG rooms (PFP-29, “Diesel Generators 31, 32 & 33”).

- Fire Zone 73A: Upper electrical penetration area (PFP-33, “Upper Electrical Penetration Area”).

- Fire Zone 74A: Lower electrical penetration area (PFP-31, “Lower Electrical Penetration Area”).

- Fire zones 3, 4, 8A, 9A, 10A, 11A, 12A, 13A, 14A, 15A, 16A, 69A: PAB 15' elevation, including RHR pump rooms (PFP-5, “Primary Auxiliary Building - Elevation 15'-0"”).

- Fire Zones 7A and 60A: Upper and lower electrical tunnels and cable spreading room (PFP-30, “Lower Electrical Tunnel” and PFP-32, “Upper Electrical Tunnel”).

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope (71111.06)

The inspectors reviewed Section 16.1 of the Final Safety Analysis Report (FSAR) that describes the flood protection features of the plant and flood mitigation equipment available to plant operators in the event of internal flooding from a potential break of a large pipe in the circulating water, condensate water, fire water, or city water systems. The inspectors also reviewed the licensee’s procedure for response to an internal flooding event, as described in off-normal operating procedure ONOP-RW-3, “Plant Flooding.” The inspectors reviewed the Indian Point 3 Individual Plant Examination for External Events (IPEEE). The IPEEE did not identify an external flooding scenario that could lead to core damage with a probability in excess of 1E-6. The inspectors reviewed operability test data for the turbine building (lower level) Level Sensors (LC-1240S and LC-1241S) in the condenser trench at the 3'-3'' elevation, which would alert operators to potential flooding in the 6900 volt switchgear. The inspectors toured the PAB, the AFW pump room, the pipe penetration area, the plant intake structure, the vital 480 volt switchgear room and the turbine building to verify that the floor drains were not blocked by debris. The inspectors also observed the general areas around the condenser water boxes to ensure that flood water flow paths were not obstructed.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope (71111.07B)

Based on a plant specific risk assessment and recent operational experience, the inspectors selected the EDG and containment fan cooler unit (FCU) heat exchangers (HXs) for this review. The EDG HXs include the jacket water and lube oil coolers which provide cooling to the EDGs to support continuous operation under full-load conditions. The five FCUs together with the containment spray system provide the design heat removal capacity for the containment building following a loss-of-coolant accident assuming that the core residual heat is released to the containment as steam. The EDG and FCU HXs transfer their heat loads directly to the service water (SW) system. The SW system was designed to supply cooling water from the Hudson River (the ultimate heat sink) to various heat sources to ensure a continuous flow of cooling water to systems and components necessary for plant safety either during normal operation, or during abnormal or accident conditions.

In their response to Generic Letter 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” Entergy committed to perform frequent periodic cleaning of essential SW HXs in lieu of testing for degraded performance. To ensure compatibility with commitments, the inspectors reviewed Entergy’s inspection, cleaning, and performance monitoring methods and frequencies. The inspectors compared surveillance test and inspection data to the licensee’s established acceptance criteria to verify that the results were acceptable and that system HX operation was consistent with the design. The inspectors walked-down the selected HXs, the two installed SW “bio boxes” (used to monitor biological fouling in the SW system), the sodium hypochlorite system, and the SW system to assess the material condition of these systems and components. The inspectors also evaluated the FCU cooling coils for indications of boric acid residue (indicative of potential reactor coolant system leakage) during a detailed containment walkdown.

The inspectors reviewed a selected sample of CRs related to the EDG and FCU HXs, and the SW system to ensure that Entergy was appropriately identifying, characterizing, and correcting problems related to these systems and components.

b. Findings

No findings of significance were identified.

1R08 In-service Inspection

Pressure Vessel Head Ultrasonic Inspection

a. Inspection Scope (71111.08 & Temporary Instruction 2515/150)

During the twelfth refueling outage (3R12) at IP3, the inspectors evaluated outage activities such as reactor pressure vessel (RPV) closure head penetration visual examination (VT), ultrasonic tests (UT), and eddy current tests (ECT). The licensee’s activities performed in response to NRC Bulletins 2001-01 and 2002-02, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” were inspected against the requirements of Temporary Instruction (TI) 2515/150 and the requirements of Commission Order EA-03-009, issued on February 11, 2003. The description of the inspection scope and results are in Section 4OA5 of this report, as specified by the TI.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Inspection

1. Biennial Review by Regional Specialist

a. Inspection Scope (71111.11B)

The following inspection activities were performed using NUREG-1021, Rev. 8, “Operator Licensing Examination Standards for Power Reactors,” Inspection Procedure Attachment 71111.11, “Licensed Operator Requalification Program,” and NRC Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process (SDP),” as acceptance criteria.

The inspectors reviewed documentation of the plant’s operating history since the last requalification program inspection, as contained in NRC inspection reports and licensee condition reports. The inspectors also discussed facility operating events with the resident staff to assess whether any operational events were indicative of training deficiencies.

The inspectors reviewed examples of the comprehensive written exams (administered by the licensee in March - April, 2002), and observed the administration of three annual operating tests to one operating crew. The inspectors reviewed the quality of the written exams and the annual operating tests to ensure they met or exceeded the criteria of the Examination Standards and 10 CFR 55.59.

The inspectors also observed operating tests administered during the week of July 28. Two scenarios were administered to an operating crew and four to a staff crew. The inspectors reviewed the exam schedule and noted that the two scenarios scheduled for the operating crew were also two of the four scenarios scheduled to be administered to the staff crew on the next day. This day-to-day overlap had the potential to reduce the discrimination validity and integrity of the examination. The training staff subsequently replaced one of the scenarios and initiated CR-IP3-2003-04469. The inspectors also observed simulator performance during the examinations, and reviewed performance testing and discrepancy reports to verify simulator compliance with the requirements of 10 CFR 55.46. A sample of records for requalification training attendance, license reactivations, and medical examinations were reviewed for compliance with license conditions and NRC regulations. Instructors, training/operations management personnel, and a sample of individual licensed operators were interviewed for feedback regarding the implementation of the licensed operator requalification program.

On August 13, 2003, the inspectors conducted an onsite review of licensee requalification exam results. These results reflected operator performance on the annual operating test. The inspection assessed whether pass rates were consistent with the guidance of NRC Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process (SDP).” The inspectors verified that:

- Crew pass rate was greater than 80%. (Pass rate was 100%.)

- Individual pass rate on the dynamic simulator test was greater than or equal to 80%. (Pass rate was 98%.)

- Individual pass rate on the walk-through test was greater than or equal to 80%. (Pass rate was 100%.)

- Overall pass rate among individuals for all portions of the exam was greater than or equal to 75%. (Pass rate was 98%.)

b. Findings

No findings of significance were identified.

2. Requalification Activities Review by Resident Staff

a. Inspection Scope (71111.11Q)

On September 8, 2003, the inspectors observed simulator training for licensed operators of Operations Team "3A" (requalification cycle 03.03.04). The inspectors reviewed an “as-found” simulator scenario, performed per lesson plan no. LRQ-SES-07, "Loss of All AC," 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) the operators’ ability to properly interpret and verify alarms; and 4) the 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. Minor deficiencies identified by the inspectors and the licensee were documented in CR-IP3-2003-5020 and CR-IP3-2003-5039.

1R12 Maintenance Effectiveness

a. Inspection Scope (71111.12Q)

The inspectors reviewed the following maintenance activities, systems and components, and recent performance issues to assess the effectiveness of the licensee's Maintenance Rule program implementation, referencing 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:

- On August 5 - 6, 2003, the inspectors observed a two-year preventive maintenance (PM) overhaul of the 31 EDG, and observed work in the field performed under WOs IP3-02-20694, IP3-02-20544, and IP3-02-20733. Additionally, the inspectors observed portions of the post-maintenance testing performed using procedure 3PT-MO79A, "31 EDG Functional Test," which was completed satisfactorily.

- During the loss of offsite power event and concurrent loss of instrument air on August 14, 2003, the installed nitrogen back-up for instrument air supply to the auxiliary feedwater regulating valves failed. This was attributed to the failure of nitrogen regulating valve IA-PCV-1276. The failure was documented in CR-IP3-2003-04717 and evaluated by systems engineering, which concluded that the AFW system was still capable of performing it's intended safety function. The inspectors evaluated the licensee's maintenance program for the nitrogen system components.

- On September 22, 2003, the licensee discovered that the electro-thermal links on the 33' Control Building fire damper FP-DF-11 were not electrically terminated for more than three days following surveillance test 3PT-R82 (CR-IP3-2003-05158). The damper is located in the fire wall separating the cable spreading room from the turbine building. The links would have functioned to close the damper in the event of a nearby fire, but would not have functioned if the carbon dioxide suppression system in the cable spreading room was actuated. The inspectors discussed with the site fire protection engineer the potential impact of this condition on the fire protection features (fire barriers, etc.) in the control building, and on the carbon dioxide suppression system. The inspectors also observed the subsequent repairs made to restore the links to functionality.

b. Findings

Introduction. A Green self-revealing finding was identified involving failure of Entergy to ensure that nitrogen regulator (valve IA-PCV-1276), which is a back-up to the instrument air supplying the auxiliary feedwater regulating valves, is capable of performing its design function. During the loss of offsite power event on August 14, 2003, the lack of back-up nitrogen pressure caused the auxiliary feedwater (AFW) regulating valves to fail to the full open position and challenged plant operators to maintain proper steam generator water levels.

Description. The inspectors determined that the nitrogen supply regulator IA-PCV-1276, which backs-up instrument air to the auxiliary feedwater regulating valves, failed to perform its intended design function during the loss of offsite power and concurrent loss of instrument air on August 14, 2003. This resulted in a loss of motive force to the AFW regulating valve air-operators and the regulating valves failed full open (by design).

On August 14, the motor-driven and turbine-driven AFW pumps started automatically in response to the loss of offsite power event. When the instrument air system pressure was lost, the nitrogen back-up system also failed to provide adequate pressure to the AFW regulating valve operators causing the valves to go full open with all three AFW pumps running. This resulted in the unregulated addition of feedwater to all four steam generators (SGs), and caused the level in the 34 SG to raise above its normal band. Also, the failure of the auxiliary feedwater regulating valves to the fully opened position removed one of the means of run-out protection to the motor driven auxiliary feedwater pumps. Consequently, operators took appropriate action to secure the AFW pumps to maintain normal steam generator water levels and compensated for the lack of feedwater flow throttling capability.

The inspectors determined that Entergy does not have a scheduled maintenance or performance monitoring program established for valve IA-PCV-1276. The absence of such a program or process has prevented the maintenance staff from identifying potential performance problems with the valve. The inspectors noted that the installed IA-PCV-1276 was a Tescom 26-1600 Series pressure reducing regulator, designed for high pressure applications. The manufacturer's published discharge specifications for this regulator cover a range of inlet pressures from a minimum of 500 psig to a maximum of 6000 psig. However, the regulator's nitrogen supply pressure is 90 psig, well below the manufacturer's specified operating range. Following the August 14 self-revealing failure of the regulator IA-PCV-1276, the regulator was replaced with an identical new regulator. However, the inspector identified that the post-maintenance testing was insufficient to demonstrate that the regulator could perform its intended back-up function. Further, Entergy did not have an evaluation to support the specific application of this high pressure regulator in a low pressure system.

Analysis. This finding is greater than minor because it affected the Mitigating Systems C ornerstone objective of equipment availability and reliability, in that the failure of the auxiliary feedwater regulating valves to the fully opened position removed one of the means of run-out protection to the motor driven auxiliary feedwater pumps. The attributes of design control and equipment performance were compromised by this specific performance deficiency. The finding was assessed using Phase I of the

Significance Determination Process for Reactor Inspection Findings for At-Power Situations and was determined to be of very low safety significance (Green). The finding is of very low safety significance because the AFW pumps were still capable of injecting water into the steam generators and operators were able to manually compensate for the failure of the feedwater regulating valves. This finding was entered in Entergy's corrective action program as CR-IP3-2003-04717 and CR-IP3-2003-04779. This finding is also associated with the Human Performance and Problem Identification and Resolution Cross-Cutting Areas. **(FIN 05000286/2003008-01)**

Enforcement. No violation of regulatory requirements occurred.

1R13 Maintenance Risk Assessment and Emergent Work Evaluation

a. Inspection Scope (71111.13)

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 IP3-03-03956; 34 SG AFW Flow Oscillations: Venting the FT-1203 Transmitter in accordance with SOP-INST-001, "Filling, Venting, and Flushing of Instrument Impulse Lines"; July 24, 2003 (CR-IP3-2003-04303).

- WOs IP3-02-01370, -02-19708, and -02-19375: Repair of slight oil leak on 32 RHR lower motor bearing, motor PM inspection/repair, and 32 RHR pump functional test; July 21 - 24, 2003.

- WO IP3-03-23914; 31 FCU excess boron accumulation in the weir drain slot; follow-up inspection of 34 FCU; September 17, 2003 (CR-IP3-2003-05133).

  During the monthly inspection for boron deposits on surfaces inside containment, the licensee observed an excess accumulation of boron around the weir drain slot of the 31 fan cooler unit (FCU). Upon further investigation of the internal surfaces of the FCU, the licensee determined that the boron originated from a pressure relief valve (SI-733B) on the 31 RHR HX that had leaked through its flange connection. The valve was located near the air inlet of the 31 FCU, and leakage from the valve was entrained into its inlet flow and condensed inside the FCU. The licensee concluded that the valve had leaked during the recent forced outage with the RHR system was in operation. The inspectors discussed the details of this situation with the primary systems engineering supervisor, and reviewed the licensee's process for completing the monthly boron inspections. The 31 FCU weir slot was subsequently cleaned to remove the excess boron.

- WO IP3-02-20694: Two-year PM overhaul of the 31 EDG; September 21 - 24, 2003.

- WO IP3-03-04077: Service Water Leak on 32 Common Control Room Air Conditioning (CCRAC) Unit Copper Pipe Braze Joint (CR-IP3-2003-05226).

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 August 14, 2003, a Northeast grid blackout caused the loss of all sources of 138 KV and 13.8 KV offsite power at the Indian Point Energy Center. The inspectors responded to the IP3 control room to observe the operators' response to this event. The loss of off-site power resulted in an expected automatic reactor trip with a loss of the normal heat sink. After the automatic reactor trip, there were a number of complications which included the premature lifting of the main steam safety valve (MS 45-4) on the 34 SG; failure of the diesel station air compressor to start; failure of the nitrogen backup to the instrument air system, and the resulting failure of the AFW flow control valves to regulate flow to the SGs; failure of the 32 source range nuclear instrument to energize; and a loss of spent fuel pool cooling. In addition, the technical support center (TSC) diesel generator did not load after it automatically started, and subsequently tripped on over speed. All three EDGs started automatically and supplied power to vital plant equipment while the off-site sources were unavailable. However, a Notice of Unusual Event (NUE) was declared based on Emergency Action Level (EAL) 6.1.1. since the safeguards buses were not capable of being energized from at least one of the 138 KV or 13.8 KV sources for greater than 15 minutes.

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 enter emergency operating procedure (EOP) ES-0.1, "Reactor Trip Response," for the loss of offsite power, to mitigate the consequences of the equipment failures noted above, and to restore the plant to its normal system configuration when off-site power was restored approximately one and one-half hours after the trip.

2. CRDM Testing

On August 20, 2003, the inspectors observed a "special evolution" of control room activities and evaluated operator performance during CRDM testing prior to a reactor start-up. The inspectors reviewed test procedure 3-TOP-198, "Control Rod Exercise Testing," and observed that operators appropriately entered off-normal procedure ONOP-RC-1, "Dropped or Misaligned Rod(s)," when control rod anomolies occurred. During the CRDM tests, the inspectors observed a locked-in ground indication on the 33 station battery charger. The inspectors evaluated the aggregate effects of this ground on the 33 125 VDC system and on overall plant safety that the ground could have had on mitigating systems during the plant startup.

3. Plant Start-Up Special Evolution

On August 20, 2003, the inspectors observed a special evolution to start up the reactor following a six-day forced maintenance outage after the Northeast grid blackout. 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 also observed operator performance to ensure that formal communications were maintained throughout the evolution, that proper controls were maintained during alarm response actions, and that the alarm response procedures were appropriately implemented when required. The inspectors also verified that proper supervisory controls were maintained over the operators in training during the start-up evolution.

b. Findings

Introduction. The inspectors identified a Green non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Actions,” involving the failure of Entergy to promptly diagnose and correct an electrical ground on the 33 125 VDC system. Entergy commenced a reactor plant heat-up, changed plant modes from Mode 5 to Mode 3, prior to evaluating the potential impact of the electrical ground. In addition, after isolating the electrical ground to the 31 EDG control panel, the licensee did not conduct a formal operability determination prior to achieving Mode1 and power operations.

Description. Inspector follow-up identified that the ground alarm indication on the 33 station battery charger had actuated on August 15, 2003. The licensee generated CR IP3-2003-04720 and concluded that the 33 125 VDC system was operable, based only on the observed voltage and current output indications of the battery charger being at their expected values. The 33 station battery charger ground detection system actuates a single light from a ground on either the positive or the negative bus. However, the detection system does not provide the ability to evaluate the existence of a short circuit or multiple grounds from opposite buses resulting in short circuits. The inspector observed that the licensee did not evaluate the possibility of more than one ground on the 33 125 VDC bus and did not conduct any ground isolation efforts until after a plant heat-up had commenced on August 20, 2003 and Mode 3 was achieved.

On the morning of August 21, 2003, the licensee determined that the ground was located in the 31 EDG control panel. However, the licensee did not attempt to further isolate the ground at that time and concluded, based upon past operating experience and judgement, that the ground did not adversely impact 31 EDG operability. The licensee continued with plant mode changes until power operation was achieved. On August 21, the licensee tagged out the 31 EDG and commenced further troubleshooting, identifying a grounded lead on the 31 EDG lube oil pressure switch being the source of the battery/31 EDG control circuit ground.

Analysis. The inspectors determined that Entergy’s failure to promptly locate and correct a ground on the 33 125 VDC bus and to thoroughly evaluate the potential adverse impact of the ground on the bus or its associated EDG is a violation of 10 CFR 50, Appendix B, Criterion VXI. Traditional enforcement does not apply because the issue was subsequently determined to have no actual safety consequences, did not impact the NRC's regulatory function, and was not the result of any willful violation of NRC requirements or Entergy procedures. The finding is greater than minor because it affects the objective of the Mitigating Systems Cornerstone to ensure the reliability and capability of critical safety equipment (125 VDC station battery and emergency diesel generator) performance, in that an unevaluated locked-in ground can potentially impact equipment functionality. The finding was assessed using Phase I of the Significance Determination Process for Reactor Inspection Findings for At-Power Situations and was determined to be of very low safety significance (Green). Following isolation of the problem to a grounded lead on the lube oil pressure switch to the 31 EDG, it was evident that the affected 33 Station Battery and 31 EDG were capable of performing their intended safety functions, absent the low probability of another simultaneous ground from the opposite bus polarity occurring. This finding is also related to the Cross-Cutting Area of Problem Identification and Resolution.

Enforcement. 10CFR50, Appendix B, Criterion XVI, states, in part, that measures shall be taken to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment are promptly identified and corrected. Contrary to the above, Entergy did not promptly identify and correct a condition adverse to quality (a known ground) on the 33 125 VDC bus or properly evaluate the potential adverse impact on the bus or its associated safety related equipment. Because the failure to identify and correct the 33 125 VDC bus ground is of very low safety significance and has been entered into Entergy's CAP (reference CR-IP3-2003-04720), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000286/2003008-02)**

1R15 Operability Evaluations

a. Inspection Scope (71111.15)

The inspectors reviewed various 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-IP3-2003-04048: OD 03-18, Eroded fuel oil pipe on 31 EDG fuel transfer system.

- CR-IP3-2003-01600: OD 03-09; 31 service water pump discharge strainer supports eroded.
- CR-IP3-2003-04536: 31 Station Battery Cell 26 Low Individual Cell Voltage.

  On August 4, 2003, the 31 station battery did not pass Technical Specification (TS) Quarterly Surveillance Requirement 3.8.6.2 when the individual cell voltage (ICV) for cell 26 was below the level specified by the Surveillance Requirement. To evaluate battery operability, the inspectors reviewed the data taken during the surveillance test and reviewed calculation IP3-CALC-EL-00184, Rev. 3, "Battery

31 System 125 VDC Component Sizing," and compared this data to the previous quarterly surveillance data to provide a reference point.

- CR-IP3-2003-04969: Potential non-conservatively high calculated net heat input.

b. Findings

Introduction. The inspectors identified a Green non-cited violation of 10CFR50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," involving the failure of Entergy to follow the quarterly surveillance procedure on August 4, 2003, and initiate actions required by Technical Specification (TS) 3.8.6 for the inoperable 31 station battery due to a low individual cell (No. 26) voltage, until prompted by the NRC Resident Inspectors.

Description. TS Limiting Condition for Operation (LCO) 3.8.6. requires the 31, 32, 33, and 34 station batteries be within the parameters specified in Table 3.8.6-1, whenever their associated DC electrical power subsystems are required to be operable. Table 3.8.6-1 defines three parameters for the battery cells (electrolyte level, float voltage, and specific gravity) and three parameter categories (A, B, and C) that establish their limits for surveillance tests conducted at 31-day and 92-day intervals. During the 92-day surveillance of the 31 battery on August 4, 2003, the licensee observed that the measured float voltage (2.06 volts) on individual cell 26 did not meet the minimum voltage specified by the Category A and B limits (2.13 volts), which requires restoration within 31 days in accordance with TS 3.8.6.A.3. Cell 26 also did not meet the Category C limit (2.07 volts), which requires entry into TS 3.8.6.A.2 and restoration of the cell to >2.07 volts within 24 hours of discovery.

On August 5, 2003, the inspectors noted that Entergy did not take the required actions of TS 3.8.6.A.2. to restore cell 26 voltage to the Category C limit, but instead declared the 31 battery operable, based on an engineering evaluation which concluded that the battery could perform its design function with one less cell than the total (59) in the entire battery bank. However, the inspectors noted this conclusion did not apply to the one degraded cell situation that could have caused the battery to become inoperable from a cell reversal or an internal short, under design basis loading conditions. The inspectors further noted that the licensee did not follow the actions specified in surveillance procedure 3PT-Q01A, Step 6.3, which requires that the licensee "take the required TS action," if the test acceptance criteria is not met.

The inspectors discussed the actions required by 3PT-Q01A and TS 3.8.6.A.2 with Entergy on the morning of August 5, 2003, and the licensee acknowledged that those actions should have been taken on the previous day. The licensee subsequently declared the 31 battery inoperable, in accordance with TS 3.8.6.B.1, obtained a spare cell and replaced degraded cell 26. The licensee declared the 31 battery operable and exited TS 3.8.4.C.1 approximately one and one-half hours before the expiration of the six hour allowed outage time and required plant shutdown. The plant remained at 100% power throughout the entire period.

Analysis. Entergy's failure to follow the 31 station battery surveillance procedure is a performance deficiency associated with the Mitigating Systems Cornerstone and contrary to NRC regulations. Traditional enforcement does not apply because the issue did not have any actual safety consequences, potential for impacting the NRC's regulatory function, and was not the result of any willful violation of NRC requirements or Entergy procedures. This finding is greater than minor because subsequent evaluation determined that the safety-related 31 station battery was adversely affected, and if left uncorrected, this condition could have resulted in a more significant safety concern (i.e., cell reversal) and loss of battery function. This finding was evaluated using Phase I of the Significance Determination Process for Reactor Inspection Findings for At-Power Situations and was determined to be of very low safety significance (Green). The safety significance is very low because of the low probability that the single degraded cell would have resulted in a cell reversal and placed an additional load on the battery that would have been sufficient to reduce overall battery capacity below its design basis loading specification. This finding is also associated with the Human Performance Cross-Cutting Area.

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. Contrary to the above, the licensee did not properly implement test procedure 3PT-Q01A, which required that the appropriate TS actions be taken when the test acceptance criteria were not met. Because the failure to follow procedures is of very low safety significance and has been entered into Entergy's CAP (reference CR-IP3-2003-04577), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000286/2003008-03)**

## 1R17 Permanent Modifications

a. Inspection Scope (71111.17A)

DCP-02-023, Rev. 0, "Replacement of PCV-1310A and PCV-1310B" in the main steam supply line to the 32 Auxiliary Boiler Feed Pump Turbine (WO IP3-020104403). The purpose of this modification was to provide larger capacity air actuators with increased margin at the nominal instrument air system pressure. Upon review of the preliminary calculation for the Air-Operated Valve Program, the licensee had discovered that for opening and closing against the design basis line pressure, the existing actuators operated with no margin. Therefore, this modification involved replacement of the original valves and operator assemblies, the existing solenoid valves with their limit switches, and the component supports. The inspectors reviewed the licensee's technical evaluation and the 10 CFR 50.59 evaluation pertaining to the modification. The inspectors also reviewed the documentation of welding and NDE results of various components in the modification package.

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 IP3-03-18855: Replacement of the impeller and seals on 32 Boric Acid Transfer Pump; and WO IP3-03-23980: 3PT-Q038B, post-maintenance test; August 13, 2003. The inspectors reviewed the scope of the testing for adequacy to ensure it would encompass all the replaced components and also evaluated the test data for completeness and accuracy.

- DCP 03-3-066: 345 KV Breaker 3 Post Work Test:

  On August 18, 2003, Entergy completed acceptance testing following the complete replacement of 345 KV Breaker 3 in the Buchanan switchyard. The original breaker was manufactured by ITE, and was removed due to past failures and replaced with a new design breaker manufactured by General Electric/Hitachi. The change-out and post-installation testing were performed under design change package DCP-03-3-066. The inspectors reviewed the DCP and evaluated the post-work testing requirements. The inspectors also observed portions of the installation and functional testing performed at the switch yard. The testing was performed in accordance with the requirements of Consolidated Edison Company Substation Engineering Department Test Standards, Specifications EI-1004-34, and was performed by three separate vendors under Entergy's supervision. The inspectors reviewed the Breaker Test Evaluation submitted by the vendors and the results of the functional testing. The inspectors also reviewed drawing 177320-42A-0 to evaluate relay functions and interconnections. The inspectors reviewed the testing criteria to ensure it was adequate to verify proper breaker operation and to verify it met the commitments of the design change package. The inspectors also verified that the test data was within its required range of acceptance criteria and that the functional testing verified that all required breaker trips functioned in accordance with their design.

- WO IP3-02-00016: 31 Station Battery Cell 26 Replacement.

  On August 4, 2003, the 31 Station Battery Cell 26 did not pass quarterly TS Surveillance Requirement 3.8.6.2 (CR-IP3-2003-04536). The inspectors observed repair work performed when the cell was replaced with a new cell, and the post-work test completed on August 11 to verify proper operation. The test consisted of an equalizing battery charge and performance of TS Surveillance Requirement 3.8.6.2 on cell 26 to verify its individual cell voltage was within specification. The inspectors reviewed the scope of the testing to ensure it would encompass the replaced components and also evaluated the test data for completeness and accuracy.

- WO IP3-03-20397 and WO IP3-03-20403 Control Rod Drive Mechanism (CRDM) cable splice replacement

  On August 16, 2003, control rods G5 and E9 did not move when shutdown bank "A" was withdrawn during an attempted reactor start-up. Upon investigation, I&C determined that the power cables to the CRDMs for these rods had developed short-circuits in cable splices that were installed as part of a cable replacement modification in 1997. Rods G5 and E9 also had blown fuses in their stationary and moveable CRDM circuits. Other blown fuses were found in rod control cabinets 2AC and 2BD. The licensee replaced eight cable splices (F8, G5, E9, B6, N9, C13, F14, and K10) that had shorted conductors and opened a representative sample of eight other splices that were apparently not shorted to determine the extent of condition. The licensee attributed the splice failures to poor workmanship during the 1997 modification, and to the high temperature conditions around the reactor head (~130F) after the four CRDM fans and the five fan cooler units tripped following the loss of offsite power.

  The inspectors entered the containment building on August 19, 2003, to observe the repair work in progress on the CRDM power cables, and observed the post-work test to verify proper control rod operation. The test consisted of withdrawing and re-inserting all control rods twenty steps one bank at a time. The inspectors reviewed the scope of the testing to ensure it would encompass all repaired components and also reviewed the test data for completeness and accuracy.

- WO IP3-03-21162; Technical Support Center (TSC) diesel generator full load test; September 16, 2003.

  The TSC diesel generator failed to load and tripped on over speed during the loss of offsite power event on August 14, 2003. Following corrective maintenance to repair the engine's electronic speed sensor and switch, and the governor stabilizer spring, the diesel was tested to 110% (616 KW) of its rated load (560 KW) in accordance with procedure 3-ENG-TSC-001, "TSC Diesel Generator Capacity Test." The inspectors observed the conduct of the test, which used a temporary load bank, and reviewed the documented test data for accuracy.

b. Findings

No findings of significance were identified.

## 1R20 Refueling and Outage Activities

a. Inspection Scope (71111.20)

Plant Shutdown - August 14, 2003

The inspectors observed activities in the control room and in the plant immediately following the Northeast grid blackout on August 14, 2003. 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,” after the reactor tripped at 4:14 p.m.. The inspectors observed the operators response to changing plant conditions using alarm response procedures and off-normal operating procedures (ONOPs) when appropriate. The inspectors evaluated operator actions for adequacy to ensure that the plant shutdown was orderly and conducted in accordance with procedures. The inspectors used plant operating procedures POP-3.1, “Plant Shutdown,” and POP-3.3, “Hot to Cold Shutdown,” to evaluate the shutdown process.

Residual Heat Removal (RHR) System Monitoring

On August 17, 2003, the licensee placed the 32 RHR pump into service to bring the plant to cold shutdown. 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 functioned properly. The inspectors periodically monitored RHR system operation throughout the plant cooldown and after the plant was stabilized in the cold shutdown condition.

Service Water System Water Hammer:

Following the complete loss of offsite power, and subsequent loss of voltage on 480 VAC safeguard buses 2A/3A, 5A and 6A, the service water (SW) pressure gauges on all three EDG jacket water and lube oil coolers were damaged by a high pressure transient (water hammer) in the service water piping (CR-IP3-2003-04732). Following the transient, the SW system continued to function normally, and no adverse effects were observed on EDG cooling. On August 16, 2003, the licensee initiated actions to evaluate 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 system engineering and no damage was observed. The licensee determined the cause of the water hammer to be a collapse of the void in the SW discharge header that formed when the EDG cooler discharge valves opened before the SW pumps started. The three SW pumps on the essential SW header started together, a short time after the EDGs started.

The inspectors evaluated the licensee’s response to this event to ensure its cause and effects were adequately understood. The inspectors also reviewed the apparent cause evaluation for technical accuracy and discussed the analysis with cognizant engineering personnel. Shortly after the water hammer, the inspectors performed an independent walk-down of the service water piping, paying particular attention to pipe supports, whip restraints, pipe flange gaskets, and system instrumentation. The inspectors noted several minor anomalies which were discussed with licensee engineering staff to ensure they would not impact system integrity.

Electrical Power

Following the restoration of off-site power, the inspectors toured the plant and periodically verified that the licensee maintained an enhanced level of protection for electrical power supplies to safety-related equipment, in accordance with Technical Specifications.

Work Clearances

The inspectors verified: a sample of work clearances and clearance tags issued during the forced maintenance outage to ensure proper installation and removal; 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 selected system configurations resulting from the clearances to ensure that the licensee maintained the minimum required boron injection pathways during the outage.

During the outage, the inspectors verified emergency power availability. In preparation for plant restart, the inspectors performed a containment walkdown to evaluate configuration control and primary system integrity. The inspectors evaluated Entergy's shutdown risk management and configuration control. In preparation for plant restart, the inspectors reviewed the control room deficiency logs and the TS Action Statement Log, and performed plant equipment walkdowns. The inspectors observed portions of the reactor startup and power ascension activities.

Monitoring of Heat-Up and Restart Activities

From August 19 - 21, 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 appropriate heat-up rate limits. Documents reviewed by the inspectors were: POP 1.1, Plant Heatup From Cold Shutdown Condition; POP 1.2, Reactor Startup; and 3PT-V053A, Power Ascension Surveillance Requirements.

Findings

b. No significant findings were identified

1R22 Surveillance Testing

a. Inspection Scope (71111.22)

The inspectors observed portions of the below listed surveillance tests and reviewed the test procedures to assess whether: 1) the test pre-conditioned 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 properly calibrated; 6) the test was performed in the proper sequence in accordance with the test procedure; and, 7) the affected system was properly restored to the correct standby configuration following the test.

- 3PT-Q080, “Pressurizer Block Valve Timing Test RC-MOV-535 and 536,” performed on July 18, 2003
- 3PT-Q134B, “32 RHR Pump Functional,” performed on July 21, 2003
- 3PC-OL27C/D, “480V Degraded Grid Voltage Relays Calibration,” performed on July 22 and 23, 2003
- 3PT-Q120B, “32 ABFP (Turbine-Driven) Surveillance and IST,” performed on August 1, 2003
- 3PT-M079B, “32 EDG Functional Test,” performed on September 3, 2003
- 3PT-Q96, “Undervoltage and Underfrequency Analog Channel Functional,” performed on September 11, 2003

b. Findings

No findings of significance were identified.

1R23 Temporary Modifications

a. Inspection Scope (71111.23)

During the week of August 18 - 22, 2003, the inspectors reviewed documentation on temporary alteration (TA) -03-3-063, “Defeat of the Interlock on Containment Purge Valves VS-FCV-1170 through 1173.” The inspectors also reviewed the WO packages (IP3-03-18650 and IP3-03-18651) for installation and removal of the TA. The TA involved the installation of an electrical jumper across designated points in the fan house control cabinet to defeat valve limit switch interlocks and to keep purge fans running for the duration of the outage (CR-IP3-2003-01626). The limit switches for containment isolation valves VS-FCV-1170, 1171, 1172 or 1173 normally provide electrical interlocks for the operation of the Containment Building Purge Supply Fan. The jumper bypassed the permissive interlock provided by the valve limit switches to keep the fans running continuously even if one of the valves were to close.

The inspectors reviewed the documentation pertaining to the above TA to ensure: 1) it was appropriately evaluated by the licensee in accordance with 10 CFR 50.59; 2) it did not adversely impact the safety function or operation of the system/component modified; and, 3) it was properly installed and removed under the licensee’s administrative controls.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP2 Alert and Notification System Testing

a. Inspection Scope (71114.02)

Entergy completed an upgrade to the siren activation and verification system in January, 2003. The inspectors reviewed Emergency Plan (E-Plan) commitments concerning the Alert and Notification System (ANS). The inspectors also reviewed procedure NEM-5.702, Revision 0, “Testing of the Indian Point Siren System,” and siren testing documentation to verify compliance with testing commitments. The inspectors interviewed the emergency preparedness (EP) Manager, the Entergy staff personnel responsible for ANS testing, and the contracted system design engineer concerning system design, operation, testing, and maintenance. The contract engineer provided a system demonstration at the control console located in the emergency operations facility, including a partial siren silent test and siren system monitoring capability. The inspectors also interviewed the cognizant staff responsible for implementation of the tone alert radio program.

The inspectors conducted the review in accordance with the guidance in NRC Inspection Procedure 71114, Attachment 02, “Alert and Notification System Testing.” The applicable planning standard in 10 CFR 50.47(b)(5), and the related requirements in 10 CFR 50 Appendix E, Section IV.D were used as acceptance and reference criteria.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing

a. Inspection Scope (71114.03)

The inspectors reviewed the licensee’s E-Plan commitments for Emergency Response Organization (ERO) staffing and emergency facility activation. The inspectors also reviewed recent quarterly call-in test results and the last two off-hours mobilization drill report to assess Entergy’s ability to augment the shift staff with sufficient responders in a timely manner. The inspectors reviewed staff depth for key ERO positions to ensure that sufficient numbers of responders were available, and also interviewed the EP Manager and the EP staff responsible for ERO augmentation testing to assess testing effectiveness and results. Lastly, the inspectors reviewed the licensee’s staffing commitments to ensure compliance with NUREG-0654, Table B-1, “Minimum Staffing Requirements for NRC Licensees For Nuclear Power Plant Emergencies.”

The inspectors conducted this review in accordance with the guidance in NRC Inspection Procedure 71114, Attachment 03, “Emergency Response Organization Augmentation.” The applicable planning standard, 10 CFR 50.47(b)(2), related requirements in 10 CFR 50, Appendix E, and the licensee’s E-Plan commitments as acceptance and reference criteria.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes

a. Inspection Scope (71114.04)

The inspectors reviewed E-Plan Revision 03-01, dated March 6, 2003, and a sampling of E-Plan implementing procedure changes to verify that the changes had not reduced the effectiveness of the E-Plan. There were no recent Emergency Action Level (EAL) changes to review.

The inspectors conducted the review in accordance with NRC Inspection Procedure 71114, Attachment 04. The applicable requirements in 10 CFR 50.54(q), 10 CFR 50.47(b), and 10 CFR 50, Appendix E were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies

a. Inspection Scope (71114.05)

The inspectors reviewed draft Audit Report A03-06-I of the Indian Point Energy Center (IPEC) Emergency Planning Program, conducted May 19 through June 12, 2003, by the quality assurance (QA) department to meet the requirements of 10 CFR 50.54(t). The inspectors reviewed the audit report to verify that it met NRC requirements, to determine QA-identified deficiencies, and to determine if any repeat issues were identified. The inspectors also interviewed the audit team leader to discuss finding details. The inspectors reviewed a sampling of CRs documenting problems and associated corrective actions to assess the licensee’s ability to identify and resolve EP issues, and to determine if corrective actions were effective to prevent recurrence. Lastly, the inspectors reviewed the 2003 focused self-assessment report titled “EP Department Program Performance” for further insights on licensee problem identification and resolution.

The inspectors conducted these reviews in accordance with Inspection Procedure 71114, Attachment 05. The applicable planning standard, 10 CFR 50.47(b)(14), and the requirements in 10 CFR 50, Appendix E, Section IV.F.2.g, were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP6 Emergency Plan Drill Evaluation

a. Inspection Scope (71114.06)

On September 24, 2003, the inspectors observed the licensee’s emergency response organization during an announced emergency preparedness training drill at Indian Point

Unit 3. The simulated emergency included activation of the Operations Support Center (OSC), the Technical Support Center (TSC), the Emergency Operations Facility (EOF), and the Joint News Center (JNC) after a simulated Alert was declared by the control room operators.

The inspectors observed the conduct of the exercise in the control room simulator, TSC, and EOF. The inspectors assessed licensed operator and ERO staff adherence to emergency plan implementation procedures and their response to simulated degraded plant conditions. The inspectors verified licensee performance in classification, notification, and protective action recommendations. In addition to the drill, the inspectors observed the licensee's controller critique and evaluated the licensee's self-identification of weaknesses and deficiencies. CR-IP3-2003-05248 concluded that six of eight performance indicator opportunities (classifications, notifications, and protective action recommendations) were successful. The inspectors compared the licensee's identified findings against their observations. The inspectors' review included the following documents and procedures:

- Indian Point Energy Center Emergency Plan
- IP-EP-410, Protective Action Recommendations, Rev 2
- IP-EP-250, Emergency Operations Facility, Rev 0
- Emergency Action Levels
- Condition Report Nos. IP3-2003-05952, IP3-2003-05248, IP3-2003-05249, IP3-2003-05251, IP3-2003-05250, IP3-2003-05279, IP3-2003-05278, and IP3-3002-05255.

b. Findings

No findings of significance were identified.

## 2. RADIATION SAFETY

Cornerstone: Public Radiation Safety (PS)

2PS2 Radioactive Material Processing and Transportation

a. Inspection Scope (71122.02)

The inspectors reviewed the radioactive material processing and transportation work activities and practices during tours of the facilities, discussed observations and issues with Entergy representatives, and inspected procedures, procedural implementation, records, and other program documents to evaluate the effectiveness of performance in this area.

Radioactive Waste System Walkdown

The inspectors walked-down selected accessible portions of the station's radioactive liquid and radioactive solid waste collection, processing, and storage systems/locations to verify that the current system configuration and operation agreed with descriptions contained in the Final Safety Analysis Report (FSAR) and the Process Control Program (PCP). The areas reviewed during the walkdowns included the following: buildings/areas within the radiologically controlled and protected areas including the primary auxiliary, fuel storage, and radioactive machine shop buildings. Also included in the walkdowns were areas outside the protected area such as the interim radioactive waste storage and steam generator mausoleum buildings, as well as the two fenced storage areas.

During a system walkdown on August 21, and during discussions with radioactive waste processing and shipping personnel, the inspectors reviewed the following: the status of non-operational and/or abandoned-in-place radioactive waste process equipment and their associated administrative and physical controls; the adequacy of any changes to the radioactive waste processing systems since the last inspection in this area and its potential radiological impact; and the current processes for transferring radioactive waste resin and filter cartridges into shipping/disposal containers and for resin dewatering.

Waste Characterization and Classification

The inspection included a review of conformance with applicable waste characterization and classification regulations and program procedures. This included a selective review of the radiochemical sample analysis results for each of the tracked radioactive waste streams and the development of scaling factors for difficult to detect and measure radionuclides. The inspectors also verified that programmatic elements were in place to ensure that determination of waste classification (10 CFR 61.55) and waste characteristics (10 CFR 61.56) were adequate, and that the waste stream composition data accounts for changing operational parameters.

Shipment Preparation

Based on the scheduled radioactive waste processing and shipment activities, the inspectors had limited opportunity to observe shipment preparation from initial packaging through final readiness for shipment. Based on the review of shipment records, radioactive waste program documents, shipment preparation procedures, and discussions with radioactive waste processing and shipping personnel, the inspectors were able to assess the adequacy of shipment preparation activities from initial packaging to shipment readiness and to determine that shipping personnel were knowledgeable of NRC and DOT shipping regulations.

Shipping Records

The inspectors examined the shipping records for five non-excepted packages including four low-specific-activity (LSA) type shipments and one surface-contaminated-object (SCO) type shipment. The inspectors reviewed these records for compliance with NRC and DOT requirements, including shipment papers and description requirements, shipper’s certification, proper use of forms, package marking and labeling, vehicle placarding, emergency response information, and packaging requirements.

The inspection included a selective review of audits and self-assessments related to the radioactive waste processing and transportation programs performed since the last inspection in this area. The inspectors also reviewed selected CRs and their corrective actions for issues related to the inspected area. Specifics regarding the corrective action program are addressed in Section 4OA2 of this report.

During the review of the five areas, which are listed above under inspection scope, the inspectors performed a selective examination of procedures, records, and documents (see attachment to this report) for regulatory compliance and adequacy.

The above review was in accordance with criteria contained in: 10 Code of Federal Regulations (CFR) Part 20: Subpart F (Surveys and monitoring); 10 CFR 20.1902 (Posting requirements); Subpart I (Storage and control of licensed material); Subpart K (Waste disposal); Appendix G to Part 20 (Requirements for transfers of low-level radioactive waste intended for disposal at licensed land disposal facilities and manifests); 10 CFR 61.55, Waste classification; 10 CFR 61.56, Waste characteristics; 10 CFR 61.57, Labeling; 10 CFR 71, Packaging and transportation of radioactive material; 49 CFR Part 172 (Hazardous materials table, special provisions, hazardous-materials communications, emergency response information, and training requirements); 49 Part 173 (Shippers-general requirements for shipments and packaging); 49 CFR Subpart I (Class 7 (radioactive materials); 49 CFR Part 177 (Carriage by public highway); NRC Bulletin 79-19; and site procedures.

b. Findings

No findings of significance were identified.

## 4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator Verification

a. Inspection Scope (71151)

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

The inspectors also reviewed the licensee's collecting and reporting process for PI data 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 were consistent with the guidance contained in Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guidelines," Rev 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.

1. Unplanned Power Changes Per 7,000 Critical Hours

The inspectors reviewed the PI for unplanned power changes per 7,000 critical hours for the period of January 2002 through June 2003. This PI monitors the rate of unplanned power changes greater than 20% of full power with less than seventy-two hours notice, 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 the PI data reported by the licensee, and compared the PI data against the guidance contained in NEI 99-02.

2. Reactor Coolant System Leak Rate

The inspectors reviewed the data the licensee submitted for the reactor coolant system (RCS) leak rate for the period of January 2002 through June 2003. The PI monitors the maximum value of total RCS identified leakage against the monthly administrative maximum of 2.5 gpm. The inspectors reviewed all of the daily leak rate source data, and selected leak rate calculations to verify the leak rate was consistent with the data submitted to the NRC.

3. Safety System Unavailability - Residual Heat Removal System

The inspectors reviewed Entergy's PI data for the RHR 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, CRs, and work orders for the first and second quarters of 2003. In addition, the inspectors interviewed the system engineers, and compared the PI data against the guidance contained in NEI 99-02.

4. <u>Emergency Preparedness</u>

The inspectors reviewed the licensee's process for identifying the data utilized for the three emergency preparedness PIs, which were: 1) Drill and Exercise Performance (DEP); 2) Emergency Response Organization (ERO) Drill Participation; and, 3) Alert and Notification System (ANS) Reliability. The inspectors also reviewed PI data from the fourth quarter of 2002 through the second quarter of 2003 using the criteria of NEI 99-02. The inspectors verified that the raw quarterly data was consistent with the data reported to the NRC.

b. <u>Findings</u>

No findings of significance were identified.

4OA2 <u>Identification and Resolution of Problems</u>

1. <u>Baseline Procedure Problem Identification and Resolution Review</u>

a. <u>Inspection Scope</u> (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) The inspectors selected an instance involving the untimely corrective action to replace a degraded power supply breaker for the 31 instrument air compressor. In March 2000, the site engineering department recommended replacement of the breaker as soon as possible after its seismic qualification was questioned due to missing fasteners internal to the breaker (DER 2000-00547). However, the replacement was subsequently characterized as elective maintenance and was eventually deferred beyond two refueling outages. In March 2003, the inspectors identified additional missing fasteners on the control power transformer inside the breaker, and further questioned the breaker's seismic qualification. That condition had not been evaluated by engineering. Although the instrument air compressor is not safety-related, its supply breaker is required to be qualified as Seismic Category I equipment so that its structural integrity will be maintained during and following a safe-shutdown earthquake (to mitigate the deleterious effects of electrical system seismic interactions). The breaker was eventually replaced in April 2003, after the inspectors questioned the licensee's process for tracking the breaker's degraded condition under Generic Letter (GL) 91-18.

The inspectors noted that the GL 91-18 process for tracking the resolution of degraded or non-conforming conditions at the site was informal and not well defined in the work control process. The electronic work order system ("Maximo") contained entries for GL 91-18 work items, but the system was not used for that purpose. Also, administrative procedure AP-8.4, "Determining the Operability of Systems, Structures, and Components," did not contain explicit instructions to document a justification for extending the resolution of degraded conditions beyond the next refueling outage.

On April 9, 2003, the licensee initiated CR-IP3-2003-02127 after a review identified six ODs and eight CRs for degraded conditions that could not be resolved during the current refueling outage (3R12). Also, on September 8, 2003, the licensee superseded procedure AP-8.4 with Revision 0 to procedure ENN-OP-104, "Operability Determinations," which contained explicit responsibilities and administrative requirements for evaluating, tracking, and resolving degraded or non-conforming conditions under the corrective action program and in accordance with GL 91-18 guidance. The inspectors discussed the details of the CR response with the licensee to assure that work items deferred beyond the 3R12 outage were appropriately justified for operability, and reviewed the program requirements in ENN-OP-104 for consistency with GL 91-18.

(2) The inspectors selected two issues identified in the corrective action program (CAP) for detailed review (CR-IP3-2002-00337 and 2003-03342) associated with a lack of initial training and with a failure to complete a quarterly inspection of radioactive material storage areas. The documented reports for the issues were reviewed to ensure that the full extent of these issues were identified, appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized.

(3) The inspectors verified that problems in the in-service inspection and non-destructive testing areas were being identified, evaluated, appropriately dispositioned, and entered into the CAP. The corrective action reports that identified and corrected problems related to in-service inspection issues are listed in the attachment to this report.

(4) Entergy documented approximately 30 CRs related to emergency siren issues at IPEC between January and July 2003. Of these, seven issues resulted in reports to the NRC in accordance with 10 CFR 50.72. The inspector selected ten CRs for detailed review, including all seven which were reported to the NRC, and one which was a roll-up analysis of all siren CRs between January and April. The inspectors reviewed the reports to ensure that the full extent of the issues were identified, an appropriate evaluation was completed, and appropriate corrective actions were prioritized and performed. The inspector discussed the reports with the EP Manager, the department corrective action coordinator, and Entergy staff personnel responsible for siren maintenance and testing.

b. <u>Findings</u>

No findings of significance were identified.

2. <u>Cross-References to Problem Identification and Resolution Findings Documented Elsewhere</u>

Section 1R12 describes a self-revealing Green finding involving the failure of Entergy to ensure that nitrogen regulator (valve IA-PCV-1276), which is a back-up to the instrument air supplying the auxiliary feedwater regulating valves, is capable of performing its design function. (This issue also has human performance elements which contributed to the finding.)

Section 1R14 describes an inspector identified Green non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," involving the failure of Entergy to promptly diagnose and correct an electrical ground on the 33 125 VDC system.

3. <u>Cross-References to Human Performance Findings Documented Elsewhere</u>

Section 1R15 describes an inspector identified Green non-cited violation of 10CFR50, Appendix B, Criterion V, "Instructions, Procedures and Drawings," involving the failure of Entergy to follow the quarterly surveillance procedure on August 4, 2003, and initiate actions required by Technical Specification (TS) 3.8.6 for the inoperable 31 station battery due to a low individual cell (No. 26) voltage.

4OA3 <u>Event Follow-up</u>

1. On August 14, 2003, Indian Point Energy Center experienced a major grid disturbance that was caused by a blackout throughout the electrical grid in the Northeast United States. The electrical disturbance and subsequent plant trip resulted in multiple plant equipment problems. The reactor automatically tripped on a loss of reactor coolant system flow in two loops after the reactor coolant pumps tripped on under-frequency following their complete loss of power.

a. <u>Inspection Scope</u> (71153)

Following the transient, the inspectors analyzed system data to assess the plant's response. The inspectors evaluated the subsequent anomalies and reviewed CRs initiated by the licensee to document problems associated with the transient:

- CR-IP3-2003-04698; Automatic reactor trip
- CR-IP3-2003-04700; Loss of spent fuel pool cooling
- CR-IP3-2003-04701; Premature lifting of MS 54-4
- CR-IP3-2003-04705; High vibrations on 33 RCP after pump restart
- CR-IP3-2003-04706; TSC diesel failed to load and tripped on over speed
- CR-IP3-2003-04707; 32 Source range instrument failed to energize
- CR-IP3-2003-04716; 8-hr battery backed Appendix R emergency lights went into a discharge cycle
- CR-IP3-2003-04717; Operator actions required to control SG level by securing AFW pumps
- CR-IP3-2003-04718; Diesel air compressor not able to supply instrument air
- CR-IP3-2003-04752; MCC-36C lost AC input due to blown fuse
- CR-IP3-2003-04779; Insufficient nitrogen flow through valve IA-PCV-1276

- CR-IP3-2003-04814; Loss of Operation's radio power following loss of offsite power

The licensee formed a Post-Transient Review Group (PTRG) which conducted interviews with the operators and analyzed plant system data to assess the plant's response to the event. The inspectors reviewed PTRG Report No. 03-05 which concluded that all systems responded within their design limits. The inspectors also evaluated the PTRG's recommended actions prior to restart.

b. Findings

No findings of significance were identified

2. Licensee Event Report Review

(Closed) LER 2003-003-00; Reactor trip associated with the failure of 345 kV breaker No. 3 on June 22, 2003, dated August 21, 2003. The details of this event and inspector observations were documented in inspection report 50-286/03-06, Section 4OA3. This LER satisfied the requirements of 10 CFR 50.73. This LER is closed.

4OA5 Other Activities

TI 2515/150 - Circumferential Cracking of RPV Head Penetration Nozzles

a. Inspection Scope

The inspectors reviewed the licensee's activities to detect circumferential cracking of reactor pressure vessel (RPV) head penetration nozzles in response to NRC Bulletins 2001-01 and 2002-02, as required by Temporary Instruction (TI) 2515/150 and Commission Order EA-03-009, issued on February 11, 2003. The inspectors interviewed test analyst personnel, reviewed qualification records and procedures, and observed selected visual examinations of the closure head. A sample of the visual examination (VT), ultrasonic tests (UT), and eddy current tests (ECT) of the RPV head penetrations were reviewed. The inspectors observed the condition of the RPV head before and after insulation removal. The inspectors reviewed the calculation and inputs utilized to determine the effective degradation years (EDY) for the RPV head. In accordance with TI 2515/150, the inspectors verified that deficiencies and discrepancies associated with the reactor coolant system (RCS) structures and the examination process, if identified, would be placed in the licensee's corrective action process. The specific reporting requirements of TI 2515/150 are documented in Attachment B.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

In late July 2003, the NRC Chairman, Nils Diaz, and the Regional Administrator for Region I, Hubert Miller, visited the Indian Point site for plant tours, discussions with station managers, and an observation of a security drill.

On October 8, 2003, the inspectors presented the inspection results to Mr. John Ventosa and Entergy staff members, and on October 9, to Mr. Chris Schwarz who acknowledged the inspection results presented. The inspectors asked the licensee what materials examined during the inspection should be considered proprietary. Some proprietary items were reviewed during the RPV head inspection, but no proprietary information is presented in this report.

ATTACHMENT A: SUPPLEMENTAL INFORMATION

ATTACHMENT B: TI 2515/150 REPORTING REQUIREMENTS

## ATTACHMENT A

## SUPPLEMENTAL INFORMATION

## KEY POINTS OF CONTACT

| | |
|---|---|
| W. Axelson | Support Supervisor |
| J. Boccio | I&C Supervisor |
| R. Christman | Superintendent, Operations Training |
| J. Comiotes | Director, Nuclear Safety Assurance |
| F. Dacimo | Site Vice President |
| M. Dampf | Health Physics Manager |
| S. Davis | Superintendent, Nuclear Training |
| G. Dean | Assistant Operations Manager - Training |
| J. DeRoy | General Manager of Engineering |
| R. Deschamps | Radiation Protection Superintendent |
| R. Discensi | Technical Support Manager |
| J. Donnelly | Corrective Actions and Assessment Manager |
| D. Gray | Environmental Engineer |
| J. Kayani | NRC GL 89-13 Program Engineer |
| A. Iavicoli | QA Lead Auditor |
| F. Inzirillo | Emergency Planning Manager |
| R. LaVera | ALARA/Planning Supervisor |
| J. LePere | Waste Services Engineer |
| J. McCann | Licensing Manager |
| R. Milici | Senior Electrical Engineer |
| E. O'Donnell | IP3 Assistant Operations Manager |
| R. Penny | Manager, Engineering Programs |
| J. Perrotta | Quality Assurance Manager |
| S. Petrosi | Design Engineering Manager |
| P. Rubin | Manager, Site Planning and Outage Services |
| C. Schwarz | General Manager, Plant Operations |
| J. Ventosa | Manager, Operations |
| A. Vitale | Operations Manager, IP3 |
| D. Wilson | Chemistry Assistant Superintendent |

## LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Closed

| | |
|---|---|
| LER 2003-003-00 | Automatic reactor trip, and on June 22, 2003, caused by a failure of 345 KV output breaker 3 (Section 4OA3). |

Opened and Closed

| | |
|---|---|
| FIN 50-286/03-08-01 | Lack of performance and condition monitoring of the nitrogen backup to the instrument air system (Section 1R12). |
| NCV 50-286/03-08-02 | Untimely corrective action to resolve a solid ground condition in the 33 125 VDC system during a plant startup (Section 1R14) |

| | |
|---|---|
| NCV 50-286/03-08-03 | Failure to take required Technical Specification actions following a failed surveillance on the 31 station battery (Section 1R15). |

## LIST OF DOCUMENTS REVIEWED

Drawings

| | |
|---|---|
| DWG 9321-F-22593 Rev. 9 | Diesel Generator Building Fuel and Jacket Water Piping Sheet 2 |
| DWG 9321-F-22583 Rev. 19 | Diesel Generator Building Fuel Oil and Jacket Water Piping |
| DWG 9321-F-32653 Rev. 8 | Heat Trace Cables Diesel Generator Fuel Oil Pit |
| DWG 9321-F-20303 Rev. 28 | Flow Diagram Fuel Oil to Diesel Generators |
| DWG 9321-F-20193 Rev. 56 | Flow Diagram Boiler Feedwater |
| DWG 9321-F-20183 Rev. 58 | Flow Diagram Condensate and Boiler Feed Pump Suction |
| DWG 9321-F-20333 Rev. 24 | Flow Diagram Service Water System |
| DWG 9321-F-20223 Rev. 9 | Flow Diagram Heater Drains and Vents |
| DWG 9321-F-20223 Rev. 30 | Flow Diagram Heater Drains and Vents |
| DWG 9321-F-30083 Rev. 52 | Single Line Diagram D.C. System |
| DWG 9321-F-27293 Rev. 31 | Flow Diagram Steam Generator Blowdown System |
| DWG 9321-F-20393, Rev. 16 | Flow Diagram Chlorination |
| DWG 9321-F-27223, Rev. 38 | Flow Diagram Service Water System Nuclear Steam Supply Plant |
| DWG 9321-F-20333, Rev. 48 | Flow Diagram Service Water System |

Work Orders

IP3-03-03882, -01714, -01853, -20758, -03182, -19500, -19501, -13450, -19999, -00016, -19960, -20382, -03480, -20400, -20397, -20403, -03077, -16537, and -04077

Work Clearances

| | |
|---|---|
| 3C13 3-EG | 31 EDG FO Transfer Pump Discharge Line, July 17, 2003 |
| 3C13 3-AFW-31 ABFP Rev. 0-0 | Motor Driven Aux. Feedwater Pump #31 |
| 3C13 3-AFW-BFD-406A MMEC Rev. 1-0 | 31 ABFP tp 31 S/G Aux. Feed Regulating Control Valve |
| 3C13 3-CRHV-32 Rev. 2-1 | CCRAC Service Water Leak |

Condition Reports

CR-IP3-2003-04048, -04253, -04255, -04272, -04279, -04291, -04298, -04300, -04303, -03346, -04381, -04382, -04121, -04386, -04414, -04419, -04218, -04214, -03998, -04494, -04498, -04501, -04506, -04495, -04514, -04603, -04608, -04598, -04613, -04594, -04747, -04746, -04752, -02598, -04614, and -04969

CR-IP3-2001-3244, -3264, -3369, -3370, -3892, -4451
CR-IP3-2002-1427, -2051, -3013, -3548, -4015, -4109, -4184, -4217, -4383, -5203
CR-IP3-2003-1572, -1574, -3462, -1970, -3472, -3772, -4403

| | |
|---|---|
| IP3-APL-02-004, Rev 0 | Service Water Chlorination Concerns |
| IP3-APL-02-005, Rev 0 | Service Water System Piping Corrosion Concerns |

Surveillance Test Procedures

| | |
|---|---|
| 3-PT-W013, Rev. 19 | Station Battery Visual Inspection |
| 3-PT-M89, Rev. 3 | #36 Station Battery Surveillance |
| 3PC-OL27D, Rev. 0 | Bus 6A 480V Degraded Grid Voltage Relays Calibration |
| 3PC-OL27C, Rev. 0 | Bus 5A 480V Degraded Grid Voltage Relays Calibration |
| 3PT-W001, Rev. 36 | Emergency Diesel Support Systems Inspection |
| 3PT-Q01A, Rev. 4 | #31 Station Battery Surveillance |
| 3PT-Q120B, Rev. 7 | 32 ABFP (Turbine Driven) Surveillance and IST |
| 3-TOP-198, Rev. 1 | Control Rod Exercise Testing |
| 3PT-M079B, Rev. 31 | 32 EDG Functional Test |
| 3PT-Q96, Rev. 8 | Undervoltage and Underfrequency Analog Channel Functional |

Calculations

| | |
|---|---|
| IP3-CALC-EL-00184, Rev. 3 | Battery 31 System 125 VDC Component Sizing |
| IP3-ANAL-ED-01636, Rev. 1 | Adjusting Adequate Auxiliary Feedwater Flow Without Aux Feed Pump Trip on Overload |
| 98-049, Rev. A | Development and Analysis of IP3 Auxiliary Feed Water System PROTO-FLO Thermal Hydraulic Model |
| SECL-00-170, Rev. 1 | Net Heat Input SECL-00-170 for Indian Point 3 |
| NSAL-03-06 | High Net Heat Input dated August 20, 2003 |

Operating and Service Instructions - SCRT/SCRF Series Battery Charger Three Phase Input - Exide

| | |
|---|---|
| 3-ARP-011 Rev. 28 | Battery Charger Trouble Alarm Response Procedure |
| ONOP-EL-7 Rev. 6 | Loss of a 480V Bus - Above Cold Shutdown |
| SOP-ESP-001 Rev. 9 | Local Operation of Safe Shutdown Equipment |
| SOP-EL-004A Rev. 6 | Electric Motor Operation |
| ONOP-IA-1 Rev. 15 | Loss of Instrument Air |
| ES-0.1 Rev. 16 | Reactor Trip Response |
| SOP-FW-004 Rev. 24 | Auxiliary Feedwater System Operation |
| SOP-RPC-006A Rev. 8 | Reactor Thermal Power Calculation |

Miscellaneous

Weekly Risk Assessment for Week 338; dated September 20, 2003

Engineering Evaluations

| | |
|---|---|
| TM 93-03547-00 | Back Up Service Water Pump Chlorination Temporary Modification |
| EVL-02-3-072 | Evaluation of EDG Operability During Repair/Replacement of EDG Return Header Vacuum Breaker SWN-69, Rev 0 |
| CR-IP3-2003-02127 | CA-5, Explicit Justification for Operability Determination: OD-02-36 Operability of SWS with Zebra/Dark False Mussels (CR-02-3548 and 02-4217) |

Procedures

| | |
|---|---|
| SOP-RW-007, Rev. 24 | Circulating and Service Water Sodium Hypochlorite Injection System |
| 3PT-Q58, Rev 14 | 38 Back-up Service Water Pump Test |
| AP-58, Rev. 3 | IP3 SWS Corrosion Monitoring Program |
| 3-COL-LV-1, Rev. 36 | Locked Valve Check-Off List |
| TSP-048, Rev. 5 | IP3 SWS Corrosion Monitoring Program Implementation Procedure |
| SOP-RW-005, Rev 29 | Service Water System Operation |
| COL-RW-2A, Rev 9 | Service Water Header Realignment |
| COL-RW-2, Rev 37 | Service Water System |
| 3-COL-RW-6, Rev. 10 | Circulating Water and Service Water Sodium Hypochlorite Injection System |

EDG Test Procedures

| | |
|---|---|
| 3PT-M079A | 31 EDG Functional Test, dated July 9, 2003 |
| 3PT-M079B | 32 EDG Functional Test, dated July 10, 2003 |
| 3PT-M079C | 33 EDG Functional Test, dated July 8, 2003 |
| HTX-003-GEN | Eddy Current Inspection of Heat Exchanger Tubes (31 EDG), dated October 3, 1999 |
| HTX-003-GEN | Eddy Current Inspection of Heat Exchanger Tubes (32 EDG), dated February 21, 2001 |
| HTX-003-GEN | Eddy Current Inspection of Heat Exchanger Tubes (33 EDG), dated January 10, 2001 |
| HTX-022-EDG | EDG Lube Oil and Jacket Water Heat Exchanger Maintenance (31 EDG), dated August 5, 2003 |
| HTX-022-EDG | EDG Lube Oil and Jacket Water Heat Exchanger Maintenance (32 EDG), dated October 1, 2002 and February 21, 2001 |
| HTX-022-EDG | EDG Lube Oil and Jacket Water Heat Exchanger Maintenance (33 EDG), dated October 29, 2002 and January 10, 2001 |

FCU Testing

Containment Fan Cooler Units Service Water Delta T Calibration, 3PC-R42, dated May 13, 2003
Fan Cooler Units 31, 32, 33, 34 and 35 Flow Balance, ENG-A648A, dated February 27, 2001
3PT-Q126, Fan Cooler Unit Operational Test, dated June 24, 2003
Preliminary Report of Eddy Current Inspection (33 FCU motor Cooler), dated June 4, 2003

| | |
|---|---|
| HTX-007-FCU | Containment Fan Cooler Unit Heat Exchanger Maintenance (31 FCU), dated September 27, 1999 |
| HTX-007-FCU | Containment Fan Cooler Unit Heat Exchanger Maintenance (32 FCU), dated October 4, 1999 |
| HTX-007-FCU | Containment Fan Cooler Unit Heat Exchanger Maintenance (33 FCU), dated June 4, 2003 |
| HTX-007-FCU | Containment Fan Cooler Unit Heat Exchanger Maintenance (34 FCU), dated February 26, 2002 |
| HTX-007-FCU | Containment Fan Cooler Unit Heat Exchanger Maintenance (35 FCU), dated July 1, 2997 |
| HTX-017-FCU | Containment Fan Cooler Unit Motor Cooler Heat Exchanger Maintenance (31 FCU), dated September 22, 1999 |
| HTX-017-FCU | Containment Fan Cooler Unit Motor Cooler Heat Exchanger Maintenance (32 FCU), dated October 4, 1999 |
| HTX-017-FCU | Containment Fan Cooler Unit Motor Cooler Heat Exchanger Maintenance (33 FCU), dated June 2, 2003 |
| HTX-017-FCU | Containment Fan Cooler Unit Motor Cooler Heat Exchanger Maintenance (34 FCU), dated September 24, 1999 |
| HTX-017-FCU | Containment Fan Cooler Unit Motor Cooler Heat Exchanger Maintenance (35 FCU), dated May 16, 2001 |

SW Test Procedures

| | |
|---|---|
| 3PT-Q092A | 31 Service Water Pump Train Operational Test, dated July 4, 2003 |
| 3PT-Q092B | 32 Service Water Pump Train Operational Test, dated July 20, 2003 |
| 3PT-Q092C | 33 Service Water Pump Train Operational Test, dated July 18, 2003 |
| 3PT-Q092D | 34 Service Water Pump Train Operational Test, dated May 30, 2003 |
| 3PT-Q092E | 35 Service Water Pump Train Operational Test, dated August 3, 2003 |
| 3PT-Q092F | 36 Service Water Pump Train Operational Test, dated June 12, 2003 |
| 3PT-Q058 | 38 Back-up Service Water Pump Test, dated June 13, 2003 |

GL 89-13 Program and Design Basis Documents

NRC Generic Letter 89-13: 2000-2002 Inspection Interval Summary, IP-PCE-02-197MC, dated November 18, 2002

NRC Generic Letter 89-13 Program Health Report, dated January 15, 2003, July 2, 2003

NYPA Letter, John C. Brons to the NRC, dated February 6, 1990 (IPN-90-004), Service Water System Problems Affecting Safety Related Equipment

NYPA Letter Ralph E. Beedle to the NRC, dated September 9, 1992 (IPN-92-040), Service Water System Problems Affecting Safety Related Equipment, Generic Letter 89-13

WCAP-12313, Safety Evaluation For an Ultimate Heat Sink Temperature Increase to $95^0$F at Indian Point Unit 3, dated July 1989

RCFC Design and Calculation RCFC-1, dated 3/26/69

2003 Indian Point Zebra Mussel Monitoring Program

EPRI NP-7552 Heat Exchanger Performance Monitoring Guidelines

Miscellaneous

Technical Specifications 3.6.5, 3.6.6, 3.7.9, and 3.7.10
UFSAR Sections 2.5, 5.3, 6.4.2, 8.2.3, 9.6.1, and 14.3.6
IP3 Service Water System Leak History, dated August 4, 2003
Risk-Informed Inspection Notebook for Indian Point Nuclear Power Plant, Unit 3, Revision 1
Indian Point 3 Nuclear Power Plant Individual Plant Examination
Indian Point 3 Nuclear Power Plant - Individual Plant Examination of External Events - IP3-RPT-UNSPEC-02182
Indian Point 3 Nuclear Power Plant - NRC Inspection Report No. 50-286/01-08
Emergency Diesel Generators Health Report, Second Quarter 2003
Service Water System Health Report, Second Quarter 2003
Containment Air Recirculation Cooling and Filtration System Health Report, Second Quarter 2003
NUREG-1275, Vol. 3 - Operating Experience Feedback Report - Service Water System Failures and Degradations

Work Orders

IP3-02-7513, -20676, -23500, -23504, -23505, -23506, -23507, -23508

Radioactive Waste System Walkdown

| | |
|---|---|
| AP-7.1, Rev. 06 | Radioactive waste reduction program |
| RE-PCP, Rev. 7 | Solid radioactive waste process control program |
| RE-RWM-12-35, Rev. 10 | Spent resin transfer |
| RE-RWM-12-28, Rev. 08 | Interim radwaste storage facility and outside radioactive material storage facilities |

Waste Characterization and Classification

Radio-chemical sample analysis results for radioactive waste streams analyzed in 2002 and 2003 and the development of scaling factors for difficult-to-detect-and-measure radionuclides

| | |
|---|---|
| RE-RWM-12-03, Rev. 08 | Waste classification compliance program |
| RE-RWM-12-39, Rev. 01 | 10CFR61 sampling |

Shipment Preparation

Radioactive material shipping logs for 2002 and 2003
Radioactive waste shipping logs for 2002 and 2003
RE-RWM-12-06, Rev. 07, Radioactive waste handling and packaging
RE-RWM-12-19, Rev. 06, Use of WMG, Inc. shipping software
RE-RWM-12-20, Rev. 14, Radioactive material shipments
RE-RWM-12-25, Rev. 02, Handling of Duratek HICs
RE-RWM-12-38, Rev. 00, Handling of the CNS 8-120B shipping cask
Certificate of compliance for radioactive material packages, Certificate No. 9168, Rev. 12, Package ID No. USA/9168/B(U), CNS-120B Type B package

Shipping Records

Shipment No. 03-56, LSA II, contaminated anti-contamination clothing
Shipment No. 03-46, SCO II, contaminated refueling equipment
Shipment No. 02-03, LSA II, dewatered spent bead resin
Shipment No. 03-01, LSA II, dry radioactive waste
Shipment No. 03-39, LSA II, dry radioactive waste

Identification and Resolution of Problems
Quality Assurance Department Audit No. A01-11I, Radiological and non-radiological effluent monitoring programs and radwaste, Fourth quarter 2001
Draft self-assessment of radioactive shipment documentation, August 2003
Condition Report Nos. CR-IP3-2002-00337 and 2003-03342

Emergency Preparedness

IP-EP-AD4, “Conduct of Drills and Exercises,” Revision 0.
IP-EP-AD5, “Emergency Preparedness Performance Indicator Program,” Revision 1.
IP-EP-AD9, “Notification Systems Testing and Maintenance,” Revision 1.
NEM-5.702, “Testing of the Indian Point Siren System,” Revision 0.
CR-IP2-2003-00756, concerning the failure of two Orange County sirens during the quarterly growl test.
CR-IP2-2003-01107, concerning the failure of all 154 sirens during cancel testing.
CR-IP2-2003-02126, concerning the loss of 10 out 16 Orange County sirens due to a loss of power to the Harriman Tower repeater site.
CR-IP2-2003-02291, concerning the loss of nine out of 16 Orange County sirens due to a power outage.
CR-IP2-2003-02382, concerning the loss of two out of 10 Putnam County sirens due to the loss of power to repeater R-257 in Rockland County.
CR-IP2-2003-02404, concerning the initiation of 27 CRs dealing with siren failures since January 1, 2003.
CR-IP2-2003-02873, concerning siren communication failures due to the terminal servers not fully responding.
CR-IP2-2003-02910, concerning the loss of all 154 sirens due to the failure of the two terminal servers in the emergency operations facility.
CR-IP2-2003-03103, concerning the loss of three out of 10 Putnam County sirens due to fuse failure at the sirens.
CR-IP2-2003-03892, concerning the loss of all 154 sirens due to computer software memory lock-up.
CR-IP3-2003-02810, concerning Emergency Planning Department’s assessment of the NUE declaration at Indian Point 3 on April 29, 2003.
Unit 3 Notification of Unusual Event Report, April 29, 2003.

## LIST OF ACRONYMS

| | |
|---|---|
| 3R12 | Indian Point 3 refueling outage no. 12 |
| AC | alternating current |
| ABFP | auxiliary boiler feedwater pump |
| AFW | auxiliary feed water |
| ANS | Alert and Notification System |
| AP | administrative procedure |
| BOP | balance of plant |
| CAP | Corrective Action Program |
| CCR | central control room |
| CCRAC | control room air conditioning |
| CDF | core damage frequency |
| CFR | Code of Federal Regulations |
| COL | check-off list |
| CR | condition report |
| CRDM | control rod drive mechanism |
| CST | condensate storage tank |
| CTO | caution tag out |
| DC | direct current |
| DCP | design change package |
| DEP | drill and exercise performance |
| DER | deficiency-event report |
| DOT | Department of Transportation |
| EAL | Emergency Action Level |
| ECT | eddy current test |
| EDG | emergency diesel generator |
| EOF | Emergency Operations Facility |
| EOP | Emergency Operating Procedure |
| EP | Emergency Preparedness |
| E-Plan | Emergency Plan |
| ERO | Emergency Response Organization |
| FCU | fan cooler unit |
| FP | fire protection |
| FSAR | Final Safety Analysis Report |
| GL | Generic Letter |
| HIC | High Integrity Container |
| Hxs | Heat Exchangers |
| HP | Health Physics |
| IAC | instrument air compressor |
| I&C | Instrument and Control |
| ICV | Individual Cell Voltage |
| IMC | Inspection Manual Chapter |
| IP2 | Indian Point 2 |
| IP3 | Indian Point 3 |
| IPEC | Indian Point Energy Center |
| IPEEE | Individual Plant Examination for External Events |
| JNC | Joint New Center |
| KV | kilo volts |
| LCO | Limiting Condition for Operation |
| LER | Licensee Event Report |

| | |
|---|---|
| LSA | Low Specific Activity |
| NCV | Non-cited Violation |
| NEI | Nuclear Energy Institute |
| NRC | Nuclear Regulatory Commission |
| OD | operability determination |
| ONOP | off-normal operating procedure |
| PAB | primary auxiliary building |
| PCP | Process Control Program |
| PFP | Pre-Fire Plan |
| PI | performance indicator |
| PM | preventive maintenance |
| PMT | post-maintenance test |
| POP | plant operating procedure |
| PS | Public Safety |
| PTRG | Post Transient Review Group |
| QA | Quality Assurance |
| RCS | reactor coolant system |
| RHR | residual heat removal |
| RPV | reactor pressure vessel |
| SAT | station auxiliary transformer |
| SCO | surface contaminated object |
| SDP | Significance Determination Process |
| SFP | spent fuel pool |
| SG | steam generator |
| SOP | system operating procedure |
| SW | service water |
| TA | temporary alteration |
| TI | Temporary Instruction |
| TS | Technical Specifications |
| TSC | Technical Support Center |
| UAT | unit auxiliary transformer |
| UT | ultrasonic test |
| VAC | volts - alternating current |
| VDC | volts - direct current |
| VT | visual test |
| WO | work order |

**Attachment B**

TI 2515/150 - Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles
Reporting Requirements

a.1 Was the examination performed by qualified and knowledgeable personnel?

The visual examination (VT) was performed by qualified and knowledgeable personnel using effective video imaging and optical equipment. The VT was done as a VT-2 type examination with evaluation by personnel qualified to the VT II or VT III level with specific training that included review of the EPRI report 1006296, revision 1 that provides visual examiners with information and guidance to detect leakage.

The eddy current (ECT) and ultrasonic examinations (UT) were performed by qualified and knowledgeable personnel using equipment and procedures that were demonstrated to be capable of identifying CRDM degradation.

a.2. Was the examination performed in accordance with approved procedures?

The VT, ECT and UT were in accordance with approved and adequate procedures.

a.3. Was the examination able to identify, disposition, and resolve deficiencies?

The examination was adequate to identify, disposition and resolve deficiencies. The inspection process included removal of the insulation, with observations made of the head prior to, during and after removal of the insulation. A detailed systematic visual examination by quadrants was made of each penetration. The VT examination documentation included a written record and video. The ECT and UT documentation included computer based data storage for ease of comparison to future examination data scans.

a.4. Was the examination capable of identifying the PWSCC phenomenon described in the bulletin?

The examination performed was capable of identifying the PWSCC phenomenon described in the Bulletin. The examination was adequate to identify, disposition and resolve deficiencies. The VT, ECT and UT examinations were complimentary to each other in providing a full outside head surface and CRDM/weld volumetric examination.

b. What was the condition of the reactor vessel head?

Numerous deposits of residual boric acid leakage were observed prior to removal of the insulation. No significant boric acid was observed during insulation removal. Examination of the head after insulation removal showed almost no boric acid present. During insulation removal a clump of material was identified resting against penetration number 72. This deposit was determined to be composed of boron and insulation. The licensee utilized the formal corrective action program and dispositioned this remnant as not an indication of an active leak since isotopic analysis showed the age of the deposit to be over 10 years and nozzle number 72 had no observed indications found under subsequent UT. It was determined that previous leakage from mechanical canopy seals in this area of the RV closure head in the early 1990’s was the most likely source of the boron. The general condition of the head was mostly clean bare metal with some small rust specs, and small spots of insulation adhesive and fibrous insulation remaining. The video taped inspection showed no boron deposits that were indicative of leakage through the CRDMs.

c. Could small boron deposits, as described in the Bulletin 01-01, be identified and characterized?

Small boron deposits, as described in Bulletin 2001-01, could have been removed during the insulation removal process. The licensee reduced the potential for losing any boron deposits during the insulation removal through detailed job controls, procedures, and pre-job briefings. The insulation removal process would have allowed significant boron deposits to be identified and remain for characterization by the visual examination technique used. None as described in Bulletin 2001-01 were found during the visual inspection.

d. What material deficiencies were identified that required repair?

No material deficiencies associated with concerns described in Bulletin 2001-01or 2002-02 were found.

e. What, if any, significant items that could impede effective examination?

No significant items were identified that could impede effective examination. The original RV head insulation (asbestos block with adhesive cement) which was an impediment to effective examination was replaced with mirror type insulation. The new insulation should not impede or otherwise hinder effective bare metal visual examinations in the future.

f. What was the basis for the temperatures used in the susceptibility ranking calculation?

3. The licensee's Reactor Vessel head closure temperatures were calculated by using a correlation developed from the Westinghouse Study of Reactor vessel upper head region fluid temperature (WCAP-9404). The licensee used plant specific inputs for RCS hot leg and cold leg temperatures recorded during routine monitoring. The licensee was not successful retrieving the same temperature data for the first three operating cycles. The temperatures obtained for cycle 4 were considered bounding for the earlier cycles due to steam generator tube plugging and the effective reduced RCS flow in cycle 4. Cycle 4 RCS temperatures were assumed for the first three operating cycles for the purpose of the susceptibility calculation.

The inspector found that the licensee' s calculation for effective degradation years (EDY) for the Indian Point Unit 3 reactor closure did not include instrument uncertainty for the Tcold and Thot measurements utilized. Since the calculation now supports the license as revised by the recent Commission Order, the licensee subsequently determined the instrument uncertainty and evaluated the impact on the susceptibility ranking calculation. Adding instrument uncertainty did not alter the plant's susceptibility category from moderate.

TI 2515/150, Sections 04.03g, 04.04f, and 04.05d require that inspectors report lower-level issues concerning data collection and analysis, and issues deemed to be significant to the phenomenon described in Bulletin 2001-01. As described above, the issue of instrument uncertainty for the susceptibility calculation was addressed by the licensee and shown not to change the resulting moderate susceptibility category for Indian Point Unit 3. A second issue with regard to record keeping as specified by procedure was identified and promptly corrected by the licensee. The licensee initiated a condition report to address the missed logging of calibration data for one of the volumetric probes as required by procedure. It was determined that the missing log entry had no impact on the data collection and analysis.