February 11, 2003

Mr. Fred Dacimo
Vice President - Indian Point Nuclear Generating Station
Entergy Nuclear Operations, Inc.
295 Broadway, Suite 1
Post Office Box 249
Buchanan, NY 10511-0249

SUBJECT: INDIAN POINT 2 - NRC INTEGRATED INSPECTION REPORT 50-247/02-07

Dear Mr. Dacimo:

On December 28, 2002, the NRC completed an inspection at the Indian Point 2 Nuclear Power Plant. The enclosed report presents the results of that inspection. The results were discussed on January 9, with members of your staff.

The inspection was an examination of activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations, and with the conditions of your license. Within these areas, the inspection consisted of a selected examination of procedures and representative records, observations of activities, and interviews with personnel. This inspection also reviewed aspects of the security physical protection program. During December 2002 and January 2003, security specialists conducted additional inspections in the physical protection cornerstone which will be documented via separate inspection reports.

Since the terrorist attacks on September 11, 2001, the NRC has issued two Orders (dated February 25, 2002, and January 7, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve readiness, and enhance access authorization. The NRC also issued Temporary Instruction 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by the February 25th Order. The TI 2515/148 audit was completed at all commercial nuclear power plants during calendar year (CY) '02, and the remaining inspections are scheduled for completion in CY '03. Additionally, table-top security drills were conducted at several licensees to evaluate licensee protection and mitigative strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the Office of Nuclear Safety and Incident Response. For CY '03, the NRC will continue to monitor overall safeguards and security controls, conduct inspections, and perform force-on-force exercises at selected power plants to pilot a long-term program that will test the adequacy of licensee security and safeguards strategies. Should threat conditions change, the NRC may issue additional Orders, advisories, and temporary instructions to contribute to the assurance of safety.

The inspectors identified five findings of very low safety significance (Green) of which four were determined to be violations of NRC requirements. However, because of their very low safety significance and because the issues have been addressed and entered into your corrective action program, the NRC is treating these issues as Non-Cited Violations, in accordance with Section VI.A.1 of the NRC's Enforcement Policy. If you deny these non-cited violations, you should provide a response with the basis for your denial, within 30 days of the receipt of this letter, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-001; with copies to the Regional Administrator, Region 1; the Director, Office of Enforcement; and the NRC Resident Inspector at the Indian Point 2 facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure 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). Should you have any questions regarding this report, please contact Mr. Peter Eselgroth at 610-337-5234.

Sincerely,

/RA/

Brian E. Holian, Deputy Director
Division of Reactor Projects

Docket No.50-247
License No. DPR-26

Enclosure: Inspection Report 50-247/02-07

Attachment 1 - Supplemental Information

cc w/encl:
J. Yelverton, Chief Executive Officer, Entergy Nuclear
M. R. Kansler, Chief Operating Officer - Entergy Nuclear Northeast
J. Herron, Senior Vice President, Indian Point Energy Station
C. Schwarz, General Manager - Plant Operations
D. Pace, Vice President - Engineering
J. Knubel, Vice President Operations Support
J. McCann, Manager, Nuclear Safety and Licensing
J. Kelly, Director, Nuclear Safety Assurance
C. Faison, Manager - Licensing
H. Salmon, Jr., Director of Oversight
J. Fulton, Assistant General Counsel, Entergy Nuclear Operations, Inc.
W. Flynn, President, New York State Energy, Research
and Development Authority

J. Spath, Program Director, New York State Energy Research
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P. Eddy, Electric Division, New York State Department of Public Service
C. Donaldson, Esquire, Assistant Attorney General, New York Department
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T. Walsh, Secretary, NFSC, Entergy Nuclear Operations, Inc.
Mayor, Village of Buchanan
J. G. Testa, Mayor, City of Peekskill
R. Albanese, Executive Chair, Four County Nuclear Safety Committee
S. Lousteau, Treasury Department, Entergy Services, Inc.
M. Slobodien, Director Emergency Programs
B. Brandenburg, Assistant General Counsel
P. Rubin, Operations Manager
Assemblywoman Sandra Galef, NYS Assembly
County Clerk, Westchester County Legislature
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R. Bondi, Putnam County Executive
C. Vanderhoef, Rockland County Executive
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Public Citizen's Critical Mass Energy Project
M. Mariotte, Nuclear Information & Resources Service
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L. Puglisi, Supervisor, Town of Cortlandt
Congresswoman Sue W. Kelly
Congresswoman Nita Lowey
Senator Hilary Rodham Clinton
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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-247
License No.	DPR-26
Report No.	50-247/02-07
Licensee:	Entergy Nuclear Operations, Inc.
Facility:	Indian Point 2 Nuclear Power Plant
Location:	Buchanan, New York 10511
Dates:	September 29 - December 28, 2002
Inspectors:	Peter Habighorst, Senior Resident Inspector Lois James, Resident Inspector Todd Fish, Sr. Operations Engineer George Malone, Operations Engineer Suresh Chaudhary, Sr. Reactor Inspector Todd Jackson, Project Engineer Monica Salter-Williams, Project Engineer John R. McFadden, Health Physicist Jason C. Jang, Senior Health Physicist E. Harold Gray, Sr. Reactor Inspector, Systems Branch, DRS Michael C. Modes, Senior Reactor Inspector Mark Cox, Resident Inspector, Indian Point Unit 3 Peter Drysdale, Senior Resident Inspector, Indian Point Unit 3 Paul Frechette, Security Inspector Leonard Cheung, Sr. Reactor Engineer Marvin Sykes, NRR, Inspection Program Branch William Cook, Senior Project Engineer
Approved by:	Peter W. Eselgroth, Chief Projects Branch 2 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000247-02-07, on September 29 - December 28, 2002, Entergy Nuclear Operations, Inc.; Indian Point 2 Nuclear Power Plant. Mitigating Systems, Barrier Integrity

The report covered a twelve week period of inspection by resident, region-based, and headquarters-based inspectors. Five findings of very low safety significance was identified. 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.

Cornerstone: Barrier Integrity

GREEN. On November 23, 2002, during a plant cool down, Entergy deviated from the guidance of plant operating procedure (POP) 3.3, Plant Cool Down, Revision 57. The consequence of the procedural deviation was to exceed the operational differential pressure limit on the steam generator tube sheet of 1600 psid (maximum value reached was approximately 1855 psid and the steam generator tube sheet design limit is 2485 psid). Accordingly, the structural integrity and qualification of the steam generator tubes was maintained. Control room operators were unaware of this operational limit and failed to question or document the technical basis for marking the applicable steps as not applicable in POP 3.3. This is considered a Non-Cited Violation of 10 CFR 50 Appendix B, Criterion V. This issue was considered more than minor because it represented a lack of understanding of procedure requirements and awareness of plant operational limitations. This finding is considered very low safety significance (Green) in accordance with NRC Manual Chapter 0609 Appendix G, in that the core cooling pathway via the steam generators was not impacted. (1R14)

Cornerstone: Mitigating Systems

GREEN. On October 9, 2002, the licensee did not identify in a timely manner that the 21 emergency diesel generator (EDG) was inoperable. The causes for the untimely operability evaluation were fragmented communications between Entergy departments, untimely drip tank sample results, poor system engineering turnover, and a lack of sensitivity to a loss of the emergency power source safety function. The time interval between the non-licensed operator having reported and added inventory to the jacket water expansion tank and the time the emergency diesel generator was declared inoperable was 7.5 hours. This time interval exceeded the limiting condition for operation within Technical Specification (TS) 3.0.1 to be in hot shutdown within seven hours. This finding affects the mitigating systems cornerstone objective and is of very low safety significance, since the 21 EDG was subsequently declared inoperable and actions within the TS were adhered to. This finding did not result in an actual loss of the emergency on-site power source safety function nor did it increase the risk significance for external events. No violations of NRC requirements were identified. (1R14)

Summary of Findings (cont'd)

GREEN. The inspector identified that Entergy, on November 10, 2002, did not document in a condition report a blown control power fuse for the 23 EDG output breaker, that subsequently was determined to be symptomatic of the same breaker failure to close on November 14, 2002. Entergy identified the cause of the November 14 breaker failure as improper operation of the inertial latch mechanism and verified acceptable operation of this latch assembly on the remaining two emergency diesel generator output breakers. This performance issue is being treated as a Non-cited Violation of 10 CFR 50 Appendix B, Criterion XVI. This violation is more than minor because the failure to document a degraded condition in a condition report precluded Entergy from tracking the performance of diesel output breakers and could have resulted in a more significant safety consequence. The potential consequence to the facility was a common mode reliability issue with all three emergency diesel generator output breakers. The issue was determined to be of very low safety significance (Green) in accordance with MC 0609
Appendix G, since greater than three offsite and onsite power sources were available to cope with a postulated loss of offsite power. (1R13)

GREEN. During preventative maintenance activities, the post work test on the 22 steam generator stop check valve (MS-41) failed to identify that the valve plug was installed upside down. This self-revealing event was identified on November 20, 2002, when operators responded to steam leak-by from this tagged closed valve. This finding is considered a Non-Cited Violation of 10 CFR 50 Appendix B, Criterion V, in that, the post-maintenance test did not adequately verify that MS-41 internals were properly re-installed. The event is considered more than minor because the improperly installed valve plug would not have been identified prior to auxiliary feedwater system operability had it not been for an unrelated tagout on the system. This is considered to be of very low risk significance in accordance with NRC MC 0609 Appendix G, since two alternate core cooling paths were available. This is an example of ineffective Entergy oversight of contractor work activities. (1R19)

GREEN. The inspector identified an example of inadequate configuration control for a safety-related system. On November 20, 2002, the inspector identified that two 125 vdc circuit breakers were in their correct position (open), but administrative locking devices were not installed. The breakers are used to cross-connect the Nos. 21 and 22 DC buses. This is considered a Non-Cited Violation of Technical Specification 6.8.1.a. and Check-Off List 27.1.6, “Instrument Buses, DC Distribution and PA Inverter,” which require the breakers to be open and locked. This performance deficiency is more than minor since more than one breaker was in the required position, but not locked open. The finding affects the mitigating systems cornerstone objective and is considered to be of very low safety significance (Green), since the operability and availability of the Nos. 21 and 22 DC buses were not adversely impacted. (1R20)

<u>Licensee-Identified Findings</u>

A violation of very low safety significance, which was identified by the licensee, was reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee’s corrective action program. This violation and the licensee’s corrective action tracking numbers are listed in Section 4AO7 of this report.

TABLE OF CONTENTS

Table of Contents (cont'd)

Report Details

SUMMARY OF PLANT STATUS

The unit began the inspection period at 100% power. Between October 8 and October 17, a planned power reduction of 0.5% occurred for replacement of main feedwater flow indicators. On October 24, the licensee initiated a down power to 85% to remove the 23 condensate pump for planned motor replacement. A power reduction continued until October 26 at midnight when operators manually tripped the reactor to begin the 15th refueling outage. The unit entered into cold shutdown on October 26 at 11:24 a.m. On December 7, 2002, the unit returned to full power following completion of the refueling outage. Except for small power reductions related to condenser backwashing and auxiliary feedwater system testing, the unit remained at full power through the end of the inspection period.

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

1R01 Adverse Weather Protection

a. Inspection Scope (71111.01)

The purpose of the inspection was to review the design and operation of the service water and boric acid heat trace systems to verify that the design features and operating procedures protect these systems from the effects of adverse weather. The inspector selected the service water system because the pumps are located outside and are required post-accident. The boric acid heat trace system was selected because of its importance for ensuring the availability of a boron source for negative reactivity addition. The documents reviewed during this inspection included:

- Individual Plant Examination (IPE).
- Updated Final Safety Analysis Report (UFSAR) Section 9.6.1, “Service Water System.”
- UFSAR Section 9.2, “Chemical and Volume Control System.”
- Abnormal Operating Procedure (AOI) 28.0.7, “Severe Weather.”
- AOI 24.1, “Service Water Malfunction.”
- System Operating Procedure (SOP) 24.1, “Service Water System Operation.”
- SOP 30.1, ”Electrical Heat Trace System.”
- Operations Administrative Step List (OASL) 15.90, ”Inclement Weather Conditions.”
- Condition Report Nos. 2002-00116, 2001-11101, 2001-08511, and 2000-10078

b. Findings

No significant findings were identified.

1R04 Equipment Alignment - Partial System Walkdowns

a. Inspection Scope (71111.04)

On October 30 and 31, the inspector performed a system walkdown of the 23 safety injection (SI) system while the 21 and 22 safety injection pumps were unavailable. The walkdown on October 30, consisted of those portions of the 23 SI train inside the vapor containment, including safety injection accumulators and recirculation pumps. On October 31, the walkdown consisted of those portions of the 23 SI train in the Primary Auxiliary and Control Buildings. The purpose of this walkdown was to verify equipment alignment and to identify any discrepancies that could impact the function of the component cooling system, thereby, potentially increasing risk. The inspector observed the physical condition of the system pump and valves, reviewed the operations logs, and reviewed the protective tagouts (PTOs) applied to the 21 and 22 SI pumps to check for adverse conditions that could potentially impact the safety injection system function. The inspector used check-off list (COL) 10.1.1, Safety Injection System, for this walkdown and reviewed plant operating procedure POP 3.3, Plant Cool Down, and the design basis document for the safety injection system to determine appropriate valve configuration.

On November 4 and 5, the inspector performed a system walkdown of the 21 residual heat removal (RHR) system while the 22 RHR pump was unavailable. The walkdown on November 4 consisted of those portions of the 21 RHR train inside the vapor containment, including valves in the recirculation pump room under the 21 RHR heat exchanger. On November 5 the walkdown consisted of those portions of the 21 RHR train in the Primary Auxiliary and Control Buildings. The purpose of this walkdown was to verify equipment alignment and identify any discrepancies that could impact the function of the component cooling system, thereby, potentially increasing risk. The inspector observed the physical condition of the system pump and valves, reviewed the operations logs, and reviewed the PTOs applied to the 22 RHR pump to check for adverse conditions that could potentially impact the system safety function. The inspector used COL 4.2.1, Residual Heat Removal System, for this walkdown and reviewed the design basis document for the RHR system to determine appropriate valve configuration.

On December 9 and 10, the inspector performed a partial system walkdown of the 21 and 23 component cooling water (CCW) system while the 22 CCW pump was unavailable. The purpose of this walkdown was to verify equipment alignment and identify any discrepancies that could impact the function of the component cooling system, thereby potentially increasing risk. The inspector observed the physical condition of the system pump and valves, reviewed the operations logs, and reviewed the PTOs applied to the 22 CCW pump to check for adverse conditions that could potentially impact the system safety function. The inspector used COL 4.1.1, Component Cooling Water, for this walkdown and reviewed design basis document for the CCW system to determine appropriate valve configuration.

b. Findings

No significant findings were identified.

1R05 Fire Protection

.1 Fire Zone Tours

a. Inspection Scope (71111.05)

The inspector toured areas important to plant safety based upon a review of Section 4.0, “Internal Fires Analysis,” and Table 4.6-2, “Summary of Core Damage Frequency Contributions from Fire Zones,” in the Indian Point 2 Individual Plant Examination for External Events (IPEEE). The objective of this inspection was to determine if the licensee had adequately controlled combustibles and ignition sources within the plant, effectively maintained fire detection and suppression capability, and adequately employed compensatory measures for degraded fire protection equipment. The inspector evaluated conditions related to the material condition, operational status, and operational lineup of fire protection systems, equipment and features; and the fire barriers used to prevent fire damage or fire propagation. The areas reviewed were:

- Fire Zone 74A, Electrical Penetration Room;
- Fire Zone 90A, Unit 2 Spent Fuel Pool Building;
- Fire Zone 32A, Electric Tunnel;
- Fire Zone 15A, valve room in the primary auxiliary building (PAB);
- Fire Zone 18A, valve room and corridor in PAB.

Reference material consulted by the inspector included the Fire Protection Implementation Plan, Pre-Fire Plan, and Station Administrative Orders (SAOs)-700, “Fire Protection and Prevention Policy,” SAO-701, “Control of Combustibles and Transient Fire Load,” SAO-703, “Fire Protection Impairment Criteria and Surveillance,” and Calculation PGI-00433, “Combustible Loading Calculation.” The inspector identified minor drawing errors in the pre-fire plan sketch. The licensee documented this deficiency in Condition Report 2002-09231.

b. Findings

No significant findings were identified.

.2 Fire Brigade Response

a. Inspection Scope (71111.05)

The inspector evaluated the fire brigade response to two separate containment fire alarms. On November 13, personnel inside containment smelled an acrid odor near a running fan and sounded the fire alarm. No fire or smoke source was identified. On November 22, electrical cable on the 95-foot elevation smoldered, burst into flames, and extinguished itself before the fire brigade arrived on the scene. The inspectors confirmed that Emergency Action Level thresholds were not achieved on either day. No damage to plant equipment or structures was identified during either fire alarm response.

The inspector observed the fire brigade response to the fire alarms to evaluate the readiness of the brigade to fight fires. In addition, the inspector reviewed the condition reports (2002-10583 and 2002-10990) generated as a result of these fire alarms to evaluate the causes of the fire, the impact on plant equipment, and the adequacy of corrective actions. The inspector did not identify any performance issues not already identified and documented in the above condition reports.

b. Findings

No significant findings were identified.

1R06 Flood Protection Measures

a. Inspection Scope (71111.06)

The inspector reviewed and toured areas containing equipment used to detect and mitigate an internal flood on various elevations within the turbine building and control building. The plant areas selected contained risk significant equipment based on the IPEEE, Section 5.0, Internal flood initiations from: circulating water in the turbine building elevation 15-foot; service water in the control building 480V emergency switchgear room; and the fire protection header in the control building deluge valve room. These three areas contribute approximately 93% of the overall core damage frequency from internal flood induced failures.

The inspector reviewed applicable licensee procedures, including abnormal operating instruction (AOI) 28.0.4, “Plant Flooding - Conventional Side,” Rev. 4. The turbine building 15-foot elevation, the control building deluge valve room, and the emergency switchgear room in the control building 15-foot elevation were walked down as part of the inspection. The inspection verified that the detection capabilities and drainage pathways were as described in the IPEEE, and that the procedure was adequate to identify potential circulating water and service water system breaches, as assumed in the IPEEE.

b. Findings

No significant findings were identified.

1R07 Heat Sink Performance

a. Inspection Scope (71111.07)

The inspector verified that the licensee’s program was adequate to ensure proper heat exchanger performance for the 23 emergency diesel generator (EDG) jacket water and lube oil coolers. The references used for this inspection included the Emergency Diesel Generator System Health Report and the EDG Basis Document. The inspector examined the material found inside the coolers and the general conditions of the cooler tubes.

The inspector reviewed heat exchanger preventive maintenance (PM) records to verify that the performance monitoring techniques and heat removal capabilities were acceptable. The inspector verified that the inspection results were appropriately compared to established acceptance criteria and the frequency of testing and inspections was sufficient. The inspector verified that the results demonstrated proper heat exchanger operation.

b. Findings

No significant findings were identified.

1R08 Inservice Inspection

.1 Steam Generator

a. Inspection Scope (71111.08)

The inspector witnessed the visual examination of the coffer damn attachment to the steam generator nozzle for steam generator No. 21 to verify conformance with the vendor recommendation for maintenance of the steam generator. The inspector reviewed the calibration and robotic set up for steam generator Nos. 21 and 24 to evaluate the location accuracy of the data set. The inspector reviewed the steam generator operational assessment for Cycle 15, the steam generator degradation assessment for refueling outage 15, and the proposed steam generator examination program for the 2002 refueling outage. The programs were reviewed and compared to actual results from the examination to determine if the licensee had a good understanding of the active degradation occurring in the generators. The inspector reviewed the results of the nondestructive testing of various components, chosen from a sample limited by the licensee's application for a risk informed inservice inspection sample set, to determine their conformance with American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, (ASME) Section XI.

The inspector reviewed the radiographs of a boiler feed water line, performed by the "gamma plug" panoramic technique, to determine conformance with ASME requirements. The inspector also reviewed and discussed with Entergy staff the use of radiography for the purpose of screening degradation of piping to determine immediate operability of leaking pipe. The inspector evaluated the level of detail applied to the workmanship sample comparison to the degradation phenomena of the radiographic technique.

b. Findings

No significant findings were identified.

.2 Reactor Pressure Vessel Closure Head Penetration Examinations/Tests

a. Inspection Scope (71111.08)

Activities inspected during refuel outage number 15 (RFO15) included 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. The description of the inspection scope and result are detailed in Section 4OA5 of this report.

b. Findings

No significant findings were identified.

1R11 Operator Requalification Inspection

.1 Licensed Operator Requalification Program Inspection

a. Inspection Scope (71111.11)

This inspection used the acceptance criteria of NUREG-1021, Revision 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)."

The inspectors reviewed documentation of operating history since the last requalification program inspection. Documents reviewed included NRC inspection reports and licensee deficiency/condition reports. The inspectors also discussed facility operating events with the resident staff. The inspectors did not identify any operational events that were indicative of possible training deficiencies.

Inspectors reviewed two examples of the comprehensive written exams (administered by the facility between February and July 2002), and observed the administration of two annual operating tests (two separate crews). The comprehensive written exams covered the facility's defined requalification period January 1, 2001 through July 7, 2002. The quality of the written exams and the annual operating tests met or exceeded the criteria of the Examination Standards and 10 CFR 55.59.

The inspectors observed simulator performance during the conduct of the examinations and reviewed performance testing and discrepancy reports to verify compliance with the requirements of 10 CFR 55.46. The most recent steady state test and transient tests for reactor startup, reactor trip, and loss of RHR were reviewed.

A sample of records for requalification training attendance, license reactivations, and medical examinations were reviewed for compliance with license conditions and NRC regulations.

Selected instructors, training/operations management personnel, and licensed operators were interviewed for gaining feedback regarding the implementation of the licensed operator requalification program.

On October 18, the inspector conducted an in-office review of licensee requalification exam results. These results included the annual operating test and comprehensive written exam. 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 inspector verified that:

- Crew pass rate was greater than 80%. (Actual pass rate was 100%)
- Individual pass rate on the dynamic simulator test was greater than or equal to 80%. (Actual pass rate was 100%)
- Individual pass rate on the walk-through test was greater than or equal to 80%. (Actual pass rate was 100%)
- Individual pass rate on the comprehensive written exam was greater than or equal to 80%. (Actual pass rate was 98%)
- Overall pass rate among individuals for all portions of the exam was greater than or equal to 75%. (Actual pass rate was 98%)

b. Findings

No significant findings were identified. These licensed operator requalification inspection results will be used by the NRC staff as part of the evaluation of the Yellow finding, during the Manual Chapter 0305, End-of-Cycle Review.

.2 Quarterly Licensed Operator Requalification Inspection

a. Inspection Scope (71111.11)

On December 12, the inspector observed the performance of an operating crew during Licensed Operator Requalification training. Specifically, the inspector observed simulator instruction, simulator demonstration, and three simulator scenarios performed by the operating crew. The inspection was conducted to assess the adequacy of the training, licensed operator performance, emergency plan implementation, and the adequacy of the licensee's critique. The inspector verified that the feedback from the instructors was thorough, identified areas for improvement, and reinforced management expectations regarding operator competencies in the areas of procedure use, communications, and peer checking.

b. Findings

No significant findings were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope (71111.12Q)

The inspector evaluated the licensee’s corrective actions for the emergency diesel generator (EDG) system equipment issues identified in October 2002 to assess the effectiveness of the licensee’s maintenance rule implementation. The inspector reviewed the EDG system performance history and assessed the licensee’s maintenance rule determination for two equipment issues: 23 EDG load oscillations when paralleled to the grid (CR 2002-09072) and 21 EDG cracked head (CR 2002-09083). The inspector reviewed the licensee’s problem identification and resolution actions for these issues to evaluate whether the licensee had appropriately monitored, evaluated, and dispositioned the issues in accordance with the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance." In addition, the inspector reviewed EDG maintenance rule classification, performance criteria, and goals.

b. Findings

No significant findings were identified.

1R13 Maintenance Risk Assessment and Emergent Work Activities

.1 23 Emergency Diesel Generator Breaker Failure to Close

a. Inspection Scope (71111.13)

The inspector observed selected portions of emergent maintenance work activities to assess the licensee’s risk management in accordance with 10 CFR 50.65 (a)(4). The inspector verified that the licensee took the necessary steps to plan and control emergent work activities, took actions to minimize the probability of initiating events, and maintained the functional capability of mitigating systems. The inspector discussed the risk management with maintenance and operations personnel for the following activities:

- Work Order (WO) IP2-02-02959, Received high steam flow alarm on panel SB-2 on October 3, 2002.
- WO IP2-02-63104, Troubleshoot cause of 23 EDG breaker not closing on November 14, 2002.

b. Findings

The inspector identified that Entergy, on November 10, did not document in a condition report a blown control power fuse for the 23 EDG output breaker, that subsequently was determined to be symptomatic of the same breaker failure to close on November 14. On November 14, Entergy identified the cause of the breaker failure as improper operation of the inertial latch mechanism and verified acceptable operation of this latch assembly on the remaining two emergency diesel generator output breakers. This performance issue is being treated as a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion XVI. This violation is more than minor because the failure to document a degraded condition in a Condition Report potentially precluded Entergy from tracking the performance of diesel output breakers and could have resulted in a more significant safety consequence. The issue was determined to be of very low safety significance (Green) in accordance with MC 0609 Appendix G, since greater than three offsite and onsite power sources were available to cope with a postulated loss of offsite power.

On November 10 the 23 EDG output breaker failed to close. Entergy's investigation identified that a control power fuse had blown in the breaker cubicle. No condition report (CR) was generated to determine the cause of the blown fuse which was replaced under OASL 15.69, Fuse Replacement Program. On November 14, the 23 EDG output breaker failed to close during surveillance test PT-R14 (CR 2002-10657). Entergy investigation (WO IP2-02-63104) determined that the inertia latch was not operating correctly and that the problem was intermittent.

10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires that in the case of significant conditions adverse to quality, measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. Contrary to this, the licensee failed to document in a CR the blown control power fuse in the 23 EDG output breaker cubicle on November 10, and failed to preclude a repeat breaker failure on November 14. This issue is being treated as a Non-Cited Violation consistent with the NRC Enforcement Policy. **(NCV 05000247/2002-007-01)**

This violation is more than minor because the failure to document a degraded condition potentially precluded Entergy from tracking the performance of diesel output breakers and could have resulted in a more significant safety consequence. Specifically, had it not been for the recollection of maintenance personnel on the breaker failure on November 10, the evaluations on November 14 would not have been as thorough. The potential consequence to the facility could have been a common-mode reliability performance issue involving all three emergency diesel generators.

.2 <u>Pressure pulsations in the Auxiliary Feedwater System During Low Flow Conditions</u>

a. <u>Inspection Scope</u> (71111.13)

The inspectors reviewed licensee actions in response to flow-induced vibrations on the motor-driven auxiliary feedwater pump suction and discharge piping. The licensee initiated condition reports (2002-10943, 2002-09871, and 10273) after observing elevated piping oscillations during the plant cool-down on October 26, 2002. The magnitude of the oscillations reached a maximum when total system flow for each pump was reduced below 120 gallons per minute (gpm). At the time, both motor driven pumps were in service and the turbine driven pump was in standby.

The inspectors evaluated the vendor's analysis for the cause of the flow-induced vibrations, corrective actions that added additional pipe supports, and the change to the recirculation flow setpoint for the 21 auxiliary feedwater pump. The inspectors also evaluated the cause and corrective actions associated with the overheating of the 21 auxiliary feedwater pump outboard packing gland on October 26 and October 30, as a consequence of the flow-induced system vibrations.

The inspectors also evaluated if the licensee could have reasonably identified the flow-induced piping oscillations previous to this plant cool down, particularly as it relates to a similar event involving the 21 auxiliary feedwater pump outboard packing gland in October 2001 (reference inspection report 50-245/2001-010).

The inspectors reviewed the following documents associated with flow-induced vibrations in the auxiliary feedwater system:

- DCP-02-2-038, "AFW Pump 21 Recirculation Flow Modification."
- Safety Evaluation 02-05250MM-00-RS, Increase in 21 AFW Recirculation Flow Controller Setpoint.
- ABS Consulting Report 1142913-R-001, IP2 Auxiliary Feedwater Pumps, Investigation of Flow Induced Vibration.
- Calculation FFX-00917-00, Evaluation of AFW Suction and Discharge Piping Subject to Pump Induced Vibration Loading.
- Generic Modification MFI-01408-88.

The inspectors also observed system testing and monitoring to validate that the flow-induced piping oscillations were appropriately resolved.

b. Findings

No significant findings were identified.

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

.1 Two Emergency Diesel Generators Inoperable

a. Inspection Scope (71111.14)

On October 8, the 23 EDG was shutdown by a non-licensed operator due to uncontrolled electrical load swings during a monthly surveillance test. On October 9, after extent-of-condition testing, the licensee identified an unrelated problem on the 21 emergency diesel generator. The diesel's 3L cylinder head had indications of an internal crack that resulted in a loss of jacket water cooling. The licensee entered into TS 3.0.1 for approximately 4.25 hours due to two of the three emergency diesel generators being inoperable. The inspectors observed operator response, reviewed operator logs, interviewed cognizant personnel, and reviewed licensee's risk assessments during this condition. The licensee documented the failures in CR Nos. 2002-9072, 2002-9083, and 2002-0911.

b. Findings

GREEN. On October 9, 2002, the licensee's organization did not identify in a timely manner that the 21 emergency diesel generator was inoperable. The causes for the untimely operability evaluation were fragmented communications between Entergy departments, untimely drip tank sample results, poor system engineering turnover, and a lack of sensitivity to a potential loss of the emergency power source safety function. At the time, the 23 emergency diesel generator was inoperable for an unrelated reason. The time between the non-licensed operator having reported and added inventory to the jacket water expansion tank and the time the emergency diesel generator was declared inoperable was 7.5 hours. During this time: operators refilled the jacket water expansion tank; the emergency diesel generator drip tank had filled with jacket water; chemists sampled its contents; and the engineering staff consulted with the diesel generator vendor.

NRC Technical Guidance 9900 documents that the timeliness of operability determinations are commensurate with the safety significance of the issue. Technical Specifications allowed outage time (AOT) provides a reasonable guideline for safety significance. In the absence of a reasonable expectation that a component will be determined operable, that component shall be declared inoperable immediately. TS 3.0.1 states that if the associated limiting condition for operation actions cannot be satisfied, because of circumstances in excess of those addressed in the specification, the unit shall be at least in hot shutdown within the next seven hours.

The untimely operability evaluation for the 21 emergency diesel generator affects the mitigating systems cornerstone objective. This finding is of very low safety significance (Green) since the 21 EDG was subsequently declared inoperable and actions within the TS were adhered to for both EDGs being out of service. This finding did not result in an actual loss of the emergency on-site power source safety function, nor did it increase the risk significance for external events. No violations of NRC requirements were identified. **(Finding 05000247/2002-007-05)**

.2 Steam Generator Tube Differential Pressure Exceeds Operational Limits During Plant Cool-down for Maintenance

a. Inspection Scope (IP 71111.14)

The inspectors evaluated licensee performance and equipment qualifications related to the discovery that a plant cool-down resulted in the steam generator tubesheet differential pressure operation limit having been exceeded. The inspectors also evaluated the impact of the pressurization on reactor coolant system (RCS) pressure boundary qualifications. The plant cool-down was initiated to identify and correct the cause of RCS leakage prior to restart from the refueling outage. Once the leak source was identified, RCS temperature and pressure were reduced to conduct repairs.

b. Findings

During the plant cool-down, the licensee deviated from the guidance of plant operating procedure (POP) 3.3, Revision 57, by maintaining RCS pressure at or near normal operating conditions while operators and maintenance crews searched for the location of the leak. To achieve these plant conditions, the operating crew, with approval from the Control Room Supervisor, marked several procedure steps as not applicable to support completion of the evolution. Consequently, steam generator tube differential pressures exceeded the 1600 pounds per square inch differential (psid) operational limit and reached a maximum value of approximately 1855 psid while RCS temperatures decreased from 475 F to 410 F. Control room operators were unaware of this operational limit. Reviews of steam generator manufacturer specifications and the UFSAR design basis accident analysis indicated that the steam generator tubes were designed to withstand up to 2485 psid during upset and hydrostatic conditions. Therefore, the structural integrity and qualification of the steam generator tubes was maintained.

The inspectors reviewed control room logs and interviewed licensee management in order to evaluate the circumstances leading to the pressurization event. The inspectors noted that licensee procedure OASL 15.84, Revision 3, “Procedure Use Documentation and Place Keeping,” allowed for marking non-conditional steps as “N/A” provided that the control room supervisor documents the reason in the control room logs. No entries were identified during review of the control room log regarding the specific plant evolution or the reason for marking the procedure steps as N/A. This is considered a Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V.

Once discovered, the licensee took immediate actions to: 1) communicate expectations to all shift operations staff regarding the use of N/A’s in non-conditional procedure steps; 2) revise POP 3.3 for plant cool-down to explain the basis for the cool-down and depressurization steps; and, 3) provide additional counseling to the on-duty senior reactor operator regarding adherence to station administrative procedures for using N/A.

This issue was considered more than minor because it represented a lack of understanding of procedure requirements and awareness of plant operational limitations. This finding is considered to be of very low safety significance (Green) in accordance with NRC Manual Chapter 0609 Appendix G, in that the core cooling pathway via the steam generators was not impacted. This issue was considered more than minor because it represented a lack of understanding of procedure requirements and awareness of plant operational limitations. **(NCV 05000247/2002-007-02)**

.3 Reactor Trip During Control Rod Testing

a. Inspection Scope (71111.14)

On November 22, a reactor trip occurred while the reactor was shutdown and control rod testing was in progress. The inspectors observed operator response, reviewed operator logs, interviewed control room personnel, and reviewed the apparent cause determination. The licensee documented the reactor trip in Condition Report 2002-10983 and completed a Post-Trip Review. A minor performance issue associated with this event is documented in Section 4OA4 of this report.

b. Findings

No significant findings were identified.

1R15 Operability Evaluations

.1 Seismic Interaction on Central Control Room Masonary Wall

a. Inspection Scope (71111.15)

The inspectors reviewed the licensee actions in response to the deficiency identified in CR 2002-09027, including the operability determination regarding the central control room (CCR) masonry wall. The CCR south masonry wall (4-053-39) was identified as inoperable because a seismic event could breach the wall and prevent the control room air filtration system from performing its design function. The inspection scope included a review of the licensee's operability determination, seismic evaluation, design requirements as described in the Final Safety Analysis Report and the drawings, the repair materials and procedure, and a visual examination and verification of the corrective measures implemented to restore the wall to operability. The review also included an examination of the evaluation performed by a consultant to determine the structural integrity and operability of the wall in the event of a design basis earthquake.

b. Findings

No significant findings were identified.

.2 23 Emergency Diesel Generator Electrical Load Swings During a Monthly Surveillance

a. Inspection Scope (71111.15)

The inspector assessed operability evaluation 02-003, "23 Emergency Diesel Generator Electrical Load Swings During Surveillance Testing," as documented in CR 2002-09072. The specific attributes reviewed included: the compliance with Technical Specifications; the licensee's proposed compensatory testing schedule; and the risk significance of the issue. The purpose of this review was to ensure that operability was properly justified and the component or system remains available, such that no appreciable increase in risk had occurred. The inspectors used Technical Specifications, applicable circuit drawings, Updated Final Safety Analysis Report, and associated Design Basis Documents as references.

b. Findings

At the close of the inspection period, no definitive root cause had been identified for the load swings. No significant findings were identified.

.3 Debris in Containment Recirculation Sump

a. Inspection Scope (71111.15)

The inspectors reviewed the operability evaluation associated with CR 2002-10431 for debris found in the containment recirculation pump sump identified during the refueling outage.

b. Findings

No significant findings were identified.

1R17 Permanent Modifications

.1 22 Station Battery Replacement

a. Inspection Scope (71111.17)

The inspector reviewed the plant modification to replace Station Battery 22 (ECP. No. DOE-02-03187-FEX, Rev. 1). From June - July 2000, the 22 battery had failed its load test. Additional testing and inspections resulted in the licensee replacing a number of battery cells and evaluating operability of the 22 battery until it could be replaced (Operability Determination 00-017). The 22 station battery was replaced in October 2002. The new battery is identical in design, construction, and materials to the old battery, and the engineering evaluation compared the revised nominal battery capacity to the old battery capacity to determine acceptability.

b. Findings

No significant findings were identified.

.2 Fuel Transfer System Upgrade

a. Inspection Scope (71111.17)

The inspectors reviewed design change package DCP-2001-08348-E, “Fuel Transfer System Upgrade,” and related procedures, drawings, and documents the licensee developed for the upgrade modification to the fuel core and component handling (FCCH) system. The modification included new equipment for the fuel transfer manipulator mast and trolley, all winches and cables for the fuel transfer carriage and upender, and all control circuits associated with the FCCH system.

The FCCH system is important to nuclear safety because the equipment is used to handle spent fuel and to safely transfer fuel assemblies between the reactor cavity and the spent fuel pool during refueling outages. The system is classified as Class “A” (safety-related) in accordance with the Indian Point 2 Quality Assurance Program Description (QAPD), Appendix A.

The inspectors evaluated the details of the modification to verify that the performance capability of the FCCH system would not be degraded as a result of the changes, and that the materials used for the modification were suitable for the service environment (flooded refueling cavity, transfer canal, and spent fuel pool). The inspectors also reviewed the licensee’s 10 CFR 50.59 impact screen (02-0275-MD-00-RS: “Fuel Transfer System Upgrade”) to verify that the conclusion for not completing a full safety evaluation for the modification was justified, and to confirm that any new failure modes introduced by the modification were bounded by existing analyses.

The inspectors observed portions of the modification installation, which included winches and cables, optical control cable links, proximity and limit switches, and position indexing encoders. The inspectors also reviewed the details of the post-installation functional tests specified in acceptance test procedures 7058374, “Manipulator Crane Upgrade,” and 70583742, “Transfer Machine Upgrade.” Portions of the functional tests were observed with the refueling cavity and transfer canal in both dry and flooded conditions to verify that safe equipment configurations were maintained, and that the appropriate acceptance criteria were met to satisfy system operability. The inspectors discussed, with project management personnel, the significance of the deviations taken to the acceptance tests to evaluate their impact on system operability.

b. Findings

No significant findings were identified.

1R19 Post Maintenance Testing

a. Inspection Scope (71111.19)

The inspector reviewed post-work test (PWT) 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 work order (WO) 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 selected testing activities involved components that were risk significant as identified in the Individual Plant Examination (IPE). The regulatory references for the inspection included Technical Specification 6.8.1.a. and 10 CFR 50, Appendix B, Criterion XIV, “Inspection, Test, and Operating Status.” The following testing activities were evaluated:

- WO IP2-02-57354, PWT to B&C Test for Valve 1786, performed on October 17, 2002.

- WO IP2-02-57748, PWT for 21 Emergency Diesel Generator Cylinder 3L jacket water leak, performed on October 10, 2002.
- WO IP2-02-65062, PWT of 21 Auxiliary feedwater pump flow to steam generators, performed on December 15, 2002.
- WO IP2-02-64963, PWT to perform PT-Q30B for 22 component cooling water pump on December 12, 2002.
- WO IP2-02-63728, PWT to perform SOP run of 22 EDG using 52/EG2B as feed on November 18, 2002.
- WO IP2-02-23403, PWT to verify no reverse flow for main steam check valve (MS-41), performed on October 27, 2002.

b. Findings

GREEN. The post work test for maintenance on the 22 steam generator stop check valve (MS-41) failed to identify that the valve plug was installed upside down. The stop check valve has two safety functions: open to supply steam to the 22 auxiliary feedwater turbine; and closed to limit offsite radiation release during a postulated steam line break. This self-revealing event was identified on November 20, when operators responded to steam leak-by from this tagged closed valve that caused a fire alarm in the auxiliary feedwater pump room.

This finding is considered a violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” in that, the post-work test, PT-R67A, Reverse Flow Check at MS-41 and MS-42 Alternate Test, Revision 1, did not adequately verify that MS-41 was properly reinstalled after preventative maintenance.

The performance finding is considered more than minor, since the improperly installed valve plug would not have been identified prior to the auxiliary feedwater system being declared operable, had it not been for an unrelated tagout on the system which revealed the degraded condition.

This performance finding is also considered to be of very low risk significance (Green), in accordance with MC 0609 Appendix G, since two alternate core cooling paths were available. On November 20, operators quickly responded to isolate the steam from inside the auxiliary feedwater building to ensure the availability of alternate core cooling pathways.

The licensee documented this event in condition report 2002-10914. The corrective actions implemented by the licensee included a stand-down of the contractor valve crew and verification of workmanship of other activities performed by this contractor. The valve was properly reinstalled and RCS heat-up recommenced. The root cause for the event was failure of the contractor technicians to refer to work package design documents during reassembly of the internals of MS-41. Contributing causes were improper shift turnovers, less than adequate contractor oversight, and failure to self-check by the technicians.

The inspector identified that the Corrective Action Review Board’s (CARB) review of the causal analysis and corrective actions for this event found that the post-work test failed to identify the improper maintenance. Further, the CARB identified that contractor workmanship and accountability required corrective actions. However, no recognition or assessment was performed on Entergy's lack of oversight of the contractor performing this safety related activity. Insufficient Entergy oversight of contractor work activities at Indian Point Unit 2 was previously documented in inspection report 50-247/2002-005. **(NCV 05000247/2002-007-03)**

1R20 Refueling and Outage Activities

.1 Plant Shutdown

a. Inspection Scope (71111.20)

The inspectors observed control room and plant activities during the plant shutdown. The inspectors verified the operators took timely and appropriate actions per emergency operating procedures E-0 and ES-0.1, when the reactor was manually scrammed at 12:00 a.m. on October 26, as part of the normal shutdown sequence. The inspectors observed the operators conduct the shutdown using procedures POP 3.1, Plant Shutdown, Revision 39, and POP 3.3, Plant Cooldown, Revision 57. The inspector observed the operators respond to changing equipment conditions with the use of alarm response procedures and abnormal operating procedures, when appropriate. The reactor was cooled down below 350 F using the AFW system, until the RHR system was placed in service. The plant entered cold shutdown with the RCS less than 200 F at approximately 11:00am on October 26. One noteworthy equipment problem was identified (see details in Section 1R13) during plant cool down. The inspectors reviewed other minor equipment issues which were documented and evaluated by the licensee in the following CRs:

- CR 2002-09565/09567, 23 Main Steam Isolation Valve Dual Position Indication.
- CR 2002-10942, High Vibration on 24 reactor coolant pump.
- CR 2002-9583, 21 steam generator level instrument failure low and 23 steam generator level instrument failure high.
- CR 2002-09597, Safety Injection Accumulator level surveillance failure.
- CR 2002-10822, 24 Battery Charger Ground.

b. Findings

No significant findings were identified.

.2 Clearances

a. Inspection Scope (71111.20)

The inspectors verified that tags and clearances were properly installed and removed and that equipment was appropriately configured to support the function of the clearance. Proper use of clearances and tagging ensured that maintenance activities were conducted in a safe environment and that water inventories in cooling systems were maintained. The inspectors reviewed the following protective tag outs (PTOs) to ensure that the licensee followed appropriate procedures:

- SIS-0033-E, 22 SI pump
- SIS-0020-C, 21 SI pump
- RHR-0002-J, 22 RHR pump
- EDG-0006, 23 EDG

The inspectors also observed the work control center and the performance of the field support supervisor who approved tag outs, dispatched personnel to install or remove the tags, and provided final disposition of removed tags. Further, the inspectors reviewed plant configurations established by the clearance tags to ensure that the licensee maintained the minimum required boron injection pathway.

b. Findings

No significant findings were identified.

.3 Refueling and Reactor Disassembly

a. Inspection Scope (71111.20)

On November 5 and 6, the inspectors observed refueling activities involving the containment manipulator crane, containment fuel transfer system, the spent fuel pool, and the control room operators. The documents reviewed by the inspectors included the Westinghouse Refueling Manual (FP-IPP-R16), and system operating procedure (SOP) 17.31, “Refueling Operation Surveillance Verification.” The inspectors observed that foreign material exclusion was being maintained in the vicinity of the spent fuel pool and the reactor cavity. The inspectors verified that fuel loading was performed consistent with the refueling manual requirements.

b. Findings

No significant findings were identified.

.4 Shutdown Risk Assessments

a. Inspection Scope (71111.20)

The inspector reviewed Entergy's refueling outage risk assessment activities to ensure that appropriate consideration was given to minimize safety system unavailability and to mitigate/compensate for periods of reduced reactivity control capability, core cooling, electrical power availability, containment integrity, spent fuel pool cooling, and reduced inventory. The inspector observed that the licensee conducted a qualitative evaluation of the daily risk associated with planned outages of both safety and non-safety related systems which contribute to the above stated attributes. In addition, the licensee assigned an overall risk characterization based upon the collective risk of all systems out-of-service at a given time. The inspector noted that as a result of the daily outage risk assessments, Entergy made some changes to the outage schedule and developed "Defense in Depth Contingency Plans" for those outage configurations which could not be otherwise modified to minimize the overall risk.

b. Findings

No significant findings were identified.

.5 Plant Heat-up and Start-up

a. Inspection Scope (71111.20)

The inspectors observed a number of plant restart activities within the control room, and during inspections of the containment, primary auxiliary building, and the auxiliary feedwater pump building. The inspectors reviewed containment cleanliness, reactor coolant system leakage calculations, containment integrity, plant heat-up, reactor start-up, and selected safety system alignment verifications. The inspectors also discussed with quality assurance surveillance personnel their concurrent observations of control room decorum. Documents that the inspectors used as reference included:

- Plant Operating Procedure (POP) 1.1, Plant Restoration from Cold Shutdown to Hot Shutdown Conditions.
- Plant Check-Off List (PCO) 1.1, Plant Heatup Above 200 F.
- POP 1.2, Reactor Startup.
- PCO-2, Plant Heatup Greater than 350F.
- POP 1.3, Plant Startup from Zero Power Condition to Full Power Operation.
- Station Administrative Order (SAO)-213, Containment Closeout (CR 2002-10894 and 2002-10893).
- Quality Assurance Surveillance Report 02-S-15-OP, CCR Activities During Startup Following 2R15.

A couple of equipment issues resulted in plant cool-down during the planned unit restart. One issue involved improper maintenance on one of the two steam admission stop check valves for the 22 auxiliary feedwater pump (see report detail 1R19). A second equipment issue also resulted in a plant cool-down and involved a reactor vessel head conoseal leak (CR 2002-10980) and canopy seal leak (CR 2002-10986). Both the conoseal and canopy seal leaks were repaired and the leakage stopped prior to proceeding with plant heat-up to normal operating temperatures.

b. Findings

GREEN. The inspector identified an example of inadequate configuration control of a safety-related system. On November 20, 2002, the inspector identified that two 125 vdc circuit breakers were in their correct position (open), but no administrative locking device was installed. The breakers, both circuit 19 on DC distribution panels 21 and 22, are used to cross-connect the Nos. 21 and 22 DC buses. Check off list (COL) 27.1.6, Instrument Buses, DC Distribution and PA Inverter, Revision 18, requires the breakers to be open and locked.

This performance deficiency is more than minor since more than one breaker was in the required position, but not locked. The finding impacts the mitigating systems cornerstone and is associated with pre-event human error. The finding is considered to be of very low safety significance (Green) since the operability and availability of the Nos. 21 and 22 DC buses were not impacted. The licensee initiated condition report 2002-10901 for this deficiency. Licensee actions were to perform a full system alignment on the 125 volt system and to evaluate the trend of configuration control problems during the refueling outage.

Technical Specification 6.8.1.a requires, in part, written procedures to be implemented for activities referenced in Appendix “A” of Regulatory Guide 1.33, Revision 2, which includes requirements for procedure adherence and operation of safety-related systems, including the 125 volt DC system. Contrary, to the above, on November 20, the inspector identified two breakers without administrative locks to preclude cross-connecting of 125 volt DC buses. **(NCV 05000247/2002-007-04)**

This finding represents a status control deficiency related to human error. The inspector selected the 125 vdc system for a partial walkdown based upon the operations decision to perform a minimal number of safety-related system alignments (approximately 38%) following the refueling outage. Further, a number of equipment configuration control problems existed during the outage for which the licensee initiated an adverse trend condition report (IP2-2002-11045). The cause of the adverse trend was less than adequate training of personnel involved in the development and maintenance of protective tagouts during the outage. Contributing causes for this adverse trend were inadequate resources being assigned and poor implementation of a new tagout process.

.6 SG Loose Parts - Detection, Retrieval, and Assessment

a. Inspection Scope (71111.20)

The inspectors evaluated Entergy’s inspection activities associated with the identification and removal of secondary side loose parts and an assessment of steam generator degradation. Entergy used a combination of detection methods which included visual inspections and non-destructive eddy current testing. Potentially damaging materials that could affect steam generator tube reliability were removed prior to unit restart.

b. Findings

No significant findings were identified.

1R22 Surveillance Testing

a. Inspection Scope (71111.22)

The inspector reviewed surveillance test procedures and observed testing activities to assess whether: 1) the test pre-conditioned the component tested; 2) the effect of the testing was adequately addressed in the control room; 3) the acceptance criteria demonstrated operational readiness consistent with design calculations and licensing documents; 4) the test equipment range and accuracy was adequate and the equipment was properly calibrated; 5) the test was performed per the procedure; 6) the test equipment was removed following testing; and, 7) test discrepancies were appropriately evaluated. The surveillance tests observed were based upon risk significant components as identified in the IPE. The regulatory requirements that provided the acceptance criteria for this review were 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," Criterion XIV, "Inspection, Test, and Operating Status," Criterion XI, "Test Control," and Technical Specifications 6.8.1.a. The following test activities were reviewed:

- PT-R6, Main Steam Safety Valve Setpoint Determination, on October 25, 2002.
- TOI 273, Appendix R Diesel Acceptance Test for Unit 2 Operability, on October 18, 2002.
- PT-R7A, Motor Driven Auxiliary Boiler Feedwater Pump Full Flow, on October 24, 2002.
- PT-R13, Safety Injection System, on November 11, 2002.
- PT-R84B, 22 EDG 8 Hour Load Test, on November 19, 2002.
- PT-R75A, Reactor Coolant System Integrity Inspection, on November 22, 2002, (CRs IP2-2002-10980, 10982, and 10986).

b. Findings

No significant findings were identified.

1R23 Temporary Plant Modifications

.1 Temporary Field Changes

a. Inspection Scope (71111.23)

The inspector reviewed the below listed Temporary Field Changes (TFCs) to ensure that: the TFC was appropriately evaluated by Entergy in accordance with 10 CFR 50.59; the TFC did not adversely impact the safety function or operation of the system/component modified; and that the TFC was appropriately installed in accordance with the licensee's administrative controls. The following TFCs were reviewed:

- TFC No. 2001-102, "Replacement Trip Transfer from Buchanan."
- TFC No. TA-02-2-079, "Modified Cap over PCV-455B Leak-off Line."

b. Findings

No significant findings were identified.

.2 Temporary Modification Associated with Augmented Spent Fuel Pool Cooling

a. Inspection Scope (71111.23)

During the weeks of October 28 and November 4, 2002, the inspector reviewed the temporary modification (TA-02-2-063) for augmented spent fuel pool cooling. The modification was designed to supplement the installed plant system in the removal of decay heat from the full core off-load to maintain an adequate working environment on the fuel handling floor. The inspector reviewed the engineering analysis for adequacy and accuracy. The inspector performed a complete system walk-down, both before and during operation, to ensure that the as-built modification matched the design configuration. Support procedure OSP 4.3.1 was reviewed for completeness and technical accuracy. The interactions between the contractor operating the equipment and the licensee operations department were also evaluated. Another temporary modification (TA-02-2-061) was used to supply 480 VAC power to the temporary spent fuel pool cooling system (TSFPCS). The inspector reviewed this modification to ensure a reliable source of power was available to the TSFPCS.

The inspector identified a number of minor deficiencies during this inspection. The lesson plan for the training of operations personnel was evaluated for accuracy and completeness. In the off-normal procedure for TSFPCS operations, it was stated that the crew would take emergency actions with the system until the contractor personnel were on scene. The inspector noted that crew training on the system consisted of a 15-minute overview and questioned the licensee on the adequacy of the training, if the operators were to operate the equipment in emergency conditions. The licensee corrected this deficiency by having crew personnel perform an extensive system walk down with the contractor. The inspector also noted that no procedural changes were in place to direct control room operators to the off-normal procedure for the TSFPCS. The licensee made a temporary procedural change to the alarm response procedure which would direct the operators to OSP 4.3.1, Attachment 3, Off-Normal Operating Procedures for the TSFPCS.

b. Findings

No significant findings were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control to Radiologically Significant Areas

a. Inspection Scope (71121.01)

The inspector observed radiological work activities and practices and procedural implementation during tours of the facility and inspected procedures, records, and other program documents to evaluate the effectiveness of the licensee's access controls to radiologically significant areas during the Cycle 15 refueling outage.

The inspector observed activities at the normal radiologically controlled area (RCA) access control point (HP-1) and at the outage RCA access control point in the maintenance outage building (MOB) to verify compliance with requirements for RCA entry and exit, dosimetry placement, and issuance and use of electronic dosimeters. On November 12, 13, and 14, 2002, the inspector toured and observed outage work activities on all elevations in the vapor containment (VC) building and on selected elevations of the primary auxiliary building (PAB) and made independent dose-rate measurements with a radiation survey meter. During tours the inspector reviewed, for regulatory compliance, the performance of radiation workers and radiation protection technicians, and the posting, labeling, barricading, and level of radiological access control for locked high radiation areas (LHRAs), high radiation areas (HRAs), radiation and contamination areas, and radioactive material areas.

On November 13, the inspector reviewed radiation work permits (RWPs) for selected activities with high dose estimates. The inspector observed pre-job briefs for the reactor head O-ring replacement and for the lifting and insertion of the reactor upper internals and watched the move of the upper internals on closed-circuit television in the health physics (HP) remote monitoring station. The inspector examined the personnel dose calculations for the noble gas contaminations which occurred on October 30, due to the inadvertent release of a gaseous waste decay tank into the VC, and the detailed investigation report prepared by the licensee.

On November 14, the inspector reviewed the root cause investigation for a LHRA incident on October 26, (CR-IP2-2002-09618) and for an airborne particulate release in the VC on November 3, (CR-IP2-2002-10049) and discussed these reports with the manager of radiological engineering. The inspector also reviewed and discussed a corrective action program report (CR-IP2-2002-10139) involving the generation and handling of a bag of radioactive waste measuring thirty rem per hour at contact on

November 5. On November 13 and 14, the inspector observed the evening HP work shift turnover meetings in the MOB building.

The inspector performed a selective examination of RWPs, procedures, records, and other program documents (as listed in the List of Documents Reviewed section) to evaluate the adequacy of radiological controls. The review was against criteria contained in 10 CFR 19.12, 10 CFR 20 (Subparts D, F, G, H, I, and J), site Technical Specifications, and site procedures.

b. Findings

No significant findings were identified.

2OS2 ALARA Planning and Controls

a. Inspection Scope (71121.02)

The inspector reviewed the effectiveness of the licensee's program to maintain occupational radiation exposure as low as is reasonably achievable (ALARA).

Between November 12 and 15, the inspector examined selected pre-job and in-progress ALARA reviews for RWPs involving jobs with the highest dose estimates. Also, the inspector performed a daily review of the refuel outage ALARA dose-tracking progress reports on RWP dose and total cumulative dose. The inspector also reviewed the station ALARA committee meeting agendas for December 4, 2001 and for October 24, 2002 which addressed the dose estimate for the Cycle 15 refueling outage. During this inspection week, the inspector interviewed numerous site HP managers, supervisors, radiological engineers, and HP technicians. As of October 24, the Unit 2 refuel outage dose estimate was approximately 161 person-rem; as of November 14, 2002, the actual total exposure was approximately 200 person-rem and the revised outage estimate was approximately 231 person-rem. The reported reasons for the increases included work scope increases, emergent work, and equipment problems encountered on modification work, along with the need for increased work planning, work preparation, coordination, and management.

The inspector performed a selective examination of records (as listed in the List of Documents Reviewed section) for regulatory compliance and for adequacy of control of radiation exposure. The review was against criteria contained in 10 CFR 20.1101 (Radiation protection programs), 10 CFR 20.1701 (Use of process or other engineering controls), and site procedures.

b. Findings

No significant findings were identified.

2OS3 Radiation Monitoring Instrumentation and Protective Equipment

a. Inspection Scope (71121.03)

The inspector reviewed the program for health physics instrumentation to determine the accuracy and operability of the instrumentation.

During the plant tours on November 12, 13, and 14, described in Section 2OS1 of this report, the inspector reviewed field instrumentation utilized by health physics technicians and plant workers to measure radioactivity and radiation levels, including portable field survey instruments, hand-held contamination frisking instruments, continuous air monitors, whole body friskers, and portal monitors. The inspector conducted a review of the instruments observed in the toured areas, specifically for verification of current calibration, of appropriate source checks, and of proper function.

The inspector performed a selective examination of documents (as listed in the List of Documents Reviewed section) for regulatory compliance and adequacy. The review was against criteria contained in 10 CFR 20.1501, 10 CFR 20 Subpart H, site Technical Specifications, and site procedures.

b. Findings

No significant findings were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection (PP)

3PP3 Response to Contingency Events

a. Inspection Scope (71130.03)

The inspectors reviewed the status of security operations and assessed licensee implementation of the protective measures in place as a result of the current, elevated threat environment.

b. Findings

No significant findings were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator Verification

The inspector reviewed the licensee's performance indicator (PI) data collecting and reporting process as described in procedure SAO-114, "Preparation of NRC and WANO Performance Indicators." The purpose of the review was to determine whether the methods for reporting PI data were consistent with the guidance contained in Nuclear

Energy Institute (NEI) 99-02, “Regulatory Assessment Performance Indicator Guidelines,” Revisions 1 and 2. The inspection included a review of the indicator definitions, data reporting elements, calculation methods, definition of terms, and clarifying notes for the performance indicators. Plant records and data were sampled and compared to the reported data. The inspector reviewed the licensee’s actions to address discrepancies in the performance indicator measurements to verify problems were satisfactorily resolved.

.1 RETS/ODCM Radiological Effluent Occurrences

a. Inspection Scope (71151)

The inspector reviewed the following documents to ensure the licensee met all requirements of the performance indicator from the first quarter 2001 to the second quarter 2002 (six quarters):

- monthly projected dose assessment results due to radioactive liquid and gaseous effluent releases;
- quarterly projected dose assessment results due to radioactive liquid and gaseous effluent releases;
- condition reports and corrective actions; and,
- associated procedures.

The inspector also performed an independent verification of the licensee’s capability for calculating projected doses to the public resulting from discharges of radioactive liquid, gases, and particulate using the licensee’s meteorological monitoring data. The licensee used its computer code for radioactive gas releases. The NRC used the NRC PC-DOSE computer code. The comparison results were evaluated.

b. Findings

No significant findings were identified.

.2 Occupation Exposure Control Effectiveness

a. Inspection Scope (71151)

The inspector selectively examined corrective action program reports for the period from August 2002 to mid-November 2002. The inspector noted that one report, CR 2002-09618, had been evaluated by the licensee as a performance indicator occurrence under the occupational radiation safety cornerstone for the fourth quarter of 2002. This item is more fully described in Section 4OA7 of this report.

b. Findings

No significant findings were identified.

.3 PI Verification - Safety System Functional Failures

a. Inspection Scope (71151)

The inspectors reviewed licensee submitted results for the third quarter 2002 for the Mitigating Systems Cornerstone, Safety System Functional Failure performance indicator for IP2 to verify individual PI accuracy and completeness. This inspection examined data and plant records for third quarter 2002, including a review of PI Data Summary Reports, Licensee Event Reports, operator narrative logs, and maintenance rule records.

b. Findings

No significant findings were identified.

4OA2 Identification and Resolution of Problems

.1 Baseline Inspection Problem Identification and Resolution

a. Inspection Scope (71152)

As part of the baseline inspection procedures, the inspectors reviewed condition reports to verify that the licensee was identifying issues at an appropriate threshold and entering them into the corrective action program. See Attachment 1 for a list of the condition reports reviewed. The inspectors examined the following considerations, as appropriate, during the condition report reviews:

– Complete and accurate identification of the problem in a timely manner;
– Evaluations and disposition of performance issues, operability/reportability issues, extent of condition, generic implications, common cause, and previous occurrences;
– Identified corrective actions were focused to correct the problem;
– Completion of corrective actions in a timely manner commensurate with the safety significance.

b. Findings

No significant findings were identified.

.2 Problem Identification and Resolution of Inservice Inspection and Nondestructive Testing

a. Inspection Scope (71152)

The inspector verified that problems in the inservice inspection (ISI) and nondestructive testing (NDE) area were being identified, evaluated, appropriately dispositioned, and entered into the corrective action program. The extent of involvement in monitoring contracted NDE tasks to provide a timely opportunity to identify and resolve problems was observed. A corrective action report that identified and corrected a problem related to an inservice inspection issue is listed in Attachment 1.

The inspector reviewed the tracking systems used by the ISI group to manage critical elements of the program such as personnel qualifications, including eye exams, and calibration of equipment. Only one problem related to ISI was identified in the last three years which required formal entry into the IP2 corrective action program. The corrective action was a minor problem with an operator, qualified to perform visual examination, failing an eye exam due to job related fatigue and was immediately remedied.

b. Findings

No significant findings were identified.

.3 Problem Identification and Resolution during 15th Refueling Outage

a. Inspection Scope (71152)

As part of the baseline inspection procedure for refueling outages (71111.20), the inspectors reviewed conditions reports to verify that the licensee was identifying issues at an appropriate threshold and entering them into the corrective action program.

b. Findings

Under report section 1R13, a very low safety significant finding was identified concerning Entergy's failure to document in a condition report the failure to close the 23 emergency diesel generator output breaker due to blown control power fuses. Further, in report section 1R19, the licensee's initial evaluation and proposed corrective actions for the improperly installed stop check valve did not identify why the post maintenance test was inadequate and did not address the adequacy of Entergy oversight of the contractor. A number of additional minor observations involving the problem identification and resolution system were evaluated by the inspectors. Two issues involving the failure of the 23 main steam isolation valve to close (CR 2002-09565) and the failure of a closing coil for a 6.9 KV breaker (CR 2002-09832) that did not identify apparent causes. Two equipment conditions involving high vibrations on the 24 reactor coolant pump during shutdown (CR 2002-10942) and a 24 vdc battery ground (CR 2002-10822) were not documented in condition reports in a timely manner. Another issue was a repeat long-standing outage condition involving reactor cavity liner leakage (CR 2002-10052).

.4 Reactor Protection System (RPS) Wiring Verification

a. Inspection Scope (71152)

The RPS wiring verification was a portion of the IP2 design basis initiative (DBI) project which started in 2001. Beginning in 1998, while implementing the design basis reconstitution program, the licensee identified many discrepancies associated with wiring configurations (actual wiring differed from drawings) in the RPS cabinets. These discrepancies were documented in 12 condition reports (CR). In 2001, the licensee consolidated all these discrepancies in one major CR (2001-00327). The licensee completed an operability determination at that time and concluded that these discrepancies did not affect the operability of the RPS. This wiring issue was reviewed by the NRC and the results were documented in inspection report IR 05000247/2001-005. Because the RPS wiring could only be carefully inspected when the reactor was shutdown, the licensee had decided to conduct a full scale wiring verification during the 2002 refueling outage.

The RPS consists of: eight RPS logic cabinets (E3 through E6 for train A, F3 through F6 for train B); two test logic cabinets (E2 for train A and F2 for train B); four engineered safeguard cabinets (E7 and E8 for train A, and F7 and F8 for train B); four auxiliary relay cabinets (G1 through G4); and four analog channel cabinets (A1 through A4). The licensee's scope of wiring verification, based on the conclusion of their evaluations, was as follows: 100% wiring verification for the 10 RPS logic and test logic cabinets; the wiring for the eight engineered safeguard and auxiliary relay cabinets was to be verified by sampling, the sample size and sampling method were based on MIL STD 105D Standard, Sampling Procedure and Table for Inspections by Attributes, dated April 29, 1963; and a limited sample on the wiring of analog channel cabinet A1 only. As of November 4, 2002, the wiring verification for the eight logic cabinets and the four engineered safeguard cabinets were completed. Three crews were working on this verification, two 12-hour day shift crews and one 12-hour night shift crew. Sufficient templates were provided to facilitate the wiring verification process. No wiring verification was performed during the week of November 4, 2002.

The inspector reviewed the project plan, the work orders associated with wiring verification, and the templates used during wiring verification to determine whether the scope was clearly defined and work activities and wiring verification templates were carefully planned. The inspector also interviewed one crew member and one crew supervisor to determine their involvement in the quality of the work. In addition, the inspector reviewed one CR (2002-09868, two relays listed on drawings were not found during verification) to determine whether the issue was appropriately characterized and properly entered into the licensee's corrective action program.

b. Findings

No significant findings were identified.

.5 Emergency Diesel Generator (EDG) 23 Panel Wiring Verification

a. Inspection Scope (71152)

EDG wiring verification was also a portion of the IP2 design basis initiative (DBI) project that started in 2001. Beginning in 1998, while implementing the design basis reconstitution program, the licensee identified discrepancies associated with wiring configurations of the EDGs. These wiring configuration issues were documented in many CRs, which were later consolidated into four main CRs (1998-00118, 2001-09001, 2001-09256, 2001-09529). During this inspection (week of November 4, 2002) EDG 23 was not required to be operable, and wiring verification of the EDG 23 control panel was in progress.

The control panels for all three EDGs are mounted side by side in the common EDG building. All panels were mounted very close to the wall without rear access doors. Each control panel has two compartments separated by a middle vertical door, which could only be partially opened. Therefore, access to the inner compartment for wiring verification was difficult.

The licensee issued the project plan in February 2002, which only briefly described the scope of the wiring verification and the projected schedule of the activities. The project plan did clearly state that the scope did not include re-wiring, and therefore the activities were not subject to 10 CFR 50, Appendix B. The verification process consisted of working notes from the crew (two members working day shift) who performed the wiring verification. The crew also completed a set of preliminary panel drawings showing the terminations of all electrical components (such as relays and terminal blocks) located in the panels. The wire numbers of the connections of each component were to be filled in during the verification process.

The inspector reviewed the project plan to determine the scope of the activities, and interviewed the two crew members and reviewed their working notes to determine the adequacy of the verification process. The inspector also observed portions of the wiring verification process to determine if any abnormal conditions occurred. In addition, the inspector also reviewed the CR (2002-10178) for a licensee identified disconnected wire in the EDG 23 starting relay circuit, to determine whether the problem was appropriately characterized (EDG 23 was inoperable at that time) and properly entered into the licensee's corrective action program.

b. Findings

No significant findings were identified.

4OA3 Event Followup

.1 (Closed) URI 05000247/00-14-04: Minimum Deliverable Refueling Water Storage Tank (RWST) Volume Design Inputs. This unresolved item identified three potentially minor RWST design discrepancies observed during a team inspection. These discrepancies were detailed in Entergy CR No. IP2-2002-04498. Inspector review of the licensee's actions to address these discrepancies is as follows:

The first discrepancy involved the adequacy of the screened vent for the RWST to pass sufficient air flow to prevent a partial vacuum during maximum tank discharge flow. The licensee had insufficient design modeling expertise to perform the needed analysis of the vent configuration and has contracted to have the analysis performed by an outside engineering firm. This issue is being appropriately tracked by the licensee's corrective action program (CA No. 00012 of 2002-004498).

The second discrepancy involved the absence of seismic analysis to demonstrate the structural adequacy of the internal vent overflow for the RWST. A regional specialist inspector reviewed the licensee's completed seismic assessment and concluded that it was acceptable.

The third discrepancy involved a potentially non-conservative RWST level at which the control room operators are required to secure the containment spray pumps, prior to establishing cold leg recirculation. The inspector reviewed the licensee's containment spray pump available net positive suction head (NPSH) calculation (No. FMX-00074-00) and RWST level instrument channel calibration and setpoint calculation (No. MPN-S65-001). The inspector concluded that the RWST level established by Emergency Operating Procedure Nos. E-1, “Loss of Reactor or Secondary Coolant,” and ES-1.3 Transfer to Cold Leg Recirculation,” provided an appropriate RWST water level (two feet, as read on LT-920 and LT-5751) to ensure sufficient NPSH to the containment spray pumps. The inspector notes that following transfer to cold leg recirculation, the containment spray pumps’ safety function has been accomplished and the pumps are no longer required per the accident analysis. This unresolved item is closed.

.2 (Closed) EEI 05000247/00-03-03: Failure to recognize long-standing difference between the design and licensing basis for the isolation valve seal water systems. NRC inspection report 50-247/200-005, Section 1R17.2, documented the licensee’s modifications to the isolation valve seal water system. This item is closed. This issue was previously evaluated for potential enforcement action in report 05000247/2000-007 and none was identified.

.3 (Closed) Licensee Event Report No. 05000247/2002-003-01: 138 KV Ground Protection Trip Results in Automatic Start of Emergency Diesel Generators, Supplement 01. Supplement 01 of LER 2002-003 revised the Entergy’s risk assessment value in terms of the industry’s standard of conditional core damage probability (CCDP) vice the licensee’s calculated instantaneous core damage frequency. The CCDP was determined to be 1.07 E-7 for this event. This LER is closed.

.4 (Closed) Licensee Event Report No. 05000247/2002-004: Security Weapon Stored in Locked Safe in the Owner Controlled Area Discovered Missing During Pre-Assignment Review. This LER documented Entergy’s discovery of a missing handgun from a locked safe located in the an office in the Owner Controlled Area (outside the protected area) and the corrective actions taken and/or in progress to prevent recurrence. Entergy concluded that the cause of the missing handgun was theft, and an investigation by local law enforcement agencies was still in progress. Entergy plans to submit a supplement to this LER upon the conclusion of the investigation. This LER is closed.

40A4 Human Performance During 15th Refuel Outage

a. Inspection Scope (71111.20)

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

b. Findings

Three very low safety significant findings (Green) were identified and documented in this inspection report involving human performance. They involved: operators lacking an understanding of procedure requirements during a plant cool down; a contractor error during maintenance on a main steam stop check valve; and an error that resulted in not installing locking devices for two 125 vdc breaker switches. The inspectors noted a number of other minor events involving the following performance issues:

- Equipment mis-positioning errors (CR Nos. 2002-10850, 2002-10853, 2002-10518).
- Inadequate equipment tagouts (CR Nos. 2002-9809, 2002-09810, and 2002-9807).
- Failure to integrate system interactions between the radioactive gas processing system and the chemical and volume control system that resulted in an unplanned spread of noble gases in the vapor containment (CR No. 2002-09819).
- Less than adequate coordination of work activities during control rod testing (CR No. 2002-10903).

Inspection follow-up of CR No. 2002-10903 identified that reactor engineering had disconnected one of the nuclear power range instruments (N-44) in preparation for low power physic testing. Disconnecting N-44 required one of the over-temperature delta temperature (OTΔT) trip bistables to be placed in the tripped position, creating a one out of three logic. Instrument and control (I&C) technicians were reconnecting the resistance temperature detectors following calibration and testing and when they re-landed the cold leg detector, there was a temperature spike causing the OTΔT bistable to trip, satisfying the logic and causing a reactor trip. The reactor trip breakers opened, as designed, which resulted in shutdown bank “A” control rods inserting into the core two steps.

Near the end of the outage, Entergy initiated an adverse trend condition report on status control of plant systems (CR IP2-2002-11045). The report evaluated fifty-two occurrences during the refueling outage. Three main groupings involved mis-positioning events, status control problems, and configuration control problems. The root cause was determined to be that training was inadequate on the tagging and work control process that had been implemented two months prior to the refueling outage. Contributing causes were inadequate resources and implementation of these two processes in close proximity to the plant outage.

4OA5 Other Activities

.1 TI 2515/150 - Circumferential Cracking of Reactor Pressure Vessel (RPV) Head Penetration Nozzles

a. Inspection Scope

Using Temporary Instruction (TI) 2515/150, the inspector reviewed the licensee's activities to detect circumferential cracking of RPV head penetration nozzles in response to NRC Bulletins 2001-01 and 2002-02. This inspection included interviews with test analyst personnel, reviews of qualification records and procedures, and observations of selected video-taped records of the vessel head visual examination. A sample of the visual examination (VT), ultrasonic tests (UT), and eddy current tests (ECT) of the RPV head penetrations were reviewed. The inspector directly observed the condition of the RPV head before and after insulation removal. The calculation and basis to determine the Effective Degradation Years (EDY) for the IP2 head were reviewed. In accordance with TI 2515/150, the inspector 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 2.

b. Findings

No significant findings were identified.

.2 TI 2515/148, Appendix A - Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures

a. Inspection Scope

An audit of the licensee's performance of the interim compensatory measures imposed by the NRC's Order Modifying License, issued February 25, 2002, was completed in accordance with the specifications of NRC Inspection Manual Temporary Instruction (TI) 2515/148, Revision 1, Appendix A, dated September 13, 2002.

b. Findings

No significant findings were identified.

4OA6 Meetings, Including Exit

The inspectors met with Indian Point 2 representatives at the conclusion of the inspection on January 8, 2002. At that time, the purpose and scope of the inspection were reviewed, and the preliminary findings were presented. The licensee acknowledged the preliminary inspection findings.

The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was reviewed during this inspection.

The inspector presented the licenced operator requalification program inspection results to members of licensee management at the conclusion of the inspection on September 19, 2002.

The inspector presented the inservice inspection (ISI) inspection results to Mr. Fred Dacimo, and other members of the licensee staff, at the conclusion of the inspection on November 8, 2002. The licensee acknowledged the conclusions and observations presented.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as Non-Cited Violation (NCV).

> Technical Specification 6.11 and Procedure HP-SQ-3.109 require that each locked high radiation area shall be guarded, locked, or constructed such that all entrances and access points prohibit unauthorized entry. Contrary to this requirement, on October 26, 2002, an access point to such an area was accessible to personnel for approximately fourteen hours, as described in the licensee's corrective action program in CR No. IP2-2002-09618. This event did not result in any unintended exposure, and other radiological controls were in place in the vicinity of this access point. This event was more than minor in that worker safety could be impacted in similar circumstances if workers made inadvertent access to an unlocked and un-posted high radiation area. Using the Occupational Radiation Safety Significance Determination Process, the issue did not result in any overexposure, did not create a substantial potential for overexposure, and did not compromise the licensee's ability to assess dose to workers. Therefore, the issue was determined to be of very low safety significance.

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

a. Key Points of Contact

N. Azevedo	ISI Supervisor
J. Comiotes	Director, Nuclear Safety Assessment
L. Cortopassi	IP3 Training Manager
F. Dacimo	Vice-President
S. Davis	IP2 Licence Operator Requalification Training Supervisor
J. DeRoy	General Manager Plant Operations, IP3
K. Finvean	Reactor Vessel Head Inspection, Assistant Project Manager
M. Gillman	IP3 Operations Manager
J. Goebel	Reactor Vessel Head Inspection, Project Manager
T. Jones	Nuclear Safety and Licensing
J. McCann	Nuclear Safety and Licensing Manager
D. Pace	VP - Engineering - ENN
J. Perrotta	Quality Assurance Manager
R. Penny	Manager, Engineering Programs
C. Schwarz	General Manager, IP2 Plant Operations
G. Schwartz	Chief Engineer
H. Salmon	Quality Assurance Director
M. Smith	Director of IP3 Engineering
J. Tuohy	Design Engineering Manager
J. Wheeler	Site Training Manager
F. Wilson	Superintendent, Operations Training
W. Axelson	Support Supervisor
T. Burns	Environmental Supervisor
M. Dampf	Health Physics Manager
R. Deschamps	Radiological Protection Superintendent
R. Decensi	Technical Support Manager
R. Fucheck	HP Supervisor
D. Gately	Radiation Protection Coordinator
L. Glander	Dosimetry Supervisor
R. LaVera	Radiological Engineer
R. Majes	Radiological Engineer
F. Mitchell	HP Supervisor
R. Richards	HP Supervisor
K. Richett	HP Technician
R. Rodino	Radiological Engineer
R. Sachatello	Radiological Consultant
R. Solanto	HP Supervisor
S. Stevens	HP Technician
J. Stewart	HP Supervisor

b. List of Items Opened, Closed, and Discussed

Closed

50-247/2000-014-04	URI	Minimum Deliverable Refueling Water Storage Tank (RWST) Volume Design Inputs.
50-247/2000-003-03	AV	Failure to recognize long-standing difference between the design and licensing basis for the isolation valve seal water system
50-247/2002-003-01	LER	138 KV Ground Protection Trip Results in Automatic Start of Emergency Diesel Generators, Supplement 01
50-247/2002-004-00	LER	Security Weapon Stored in Locked Safe in the Owner Controlled Area Discovered Missing During Pre-Assignment Review.

Open/Closed

50-247/2002-007-001	NCV	Failure of 23 EDG output breaker to close
50-247/2002-007-002	NCV	Operators did not recognize operational limits on steam generator tubesheet during plant cool down
50-247/2002-007-003	NCV	Post-work test inadequate for steam stop check valve
50-247/2002-007-004	NCV	TS 6.8.1 violation on 125 vdc breaker administrative controls
50-247/2002-007-005	Finding	Untimely declaration of EDG inoperability.

c. List of Documents Reviewed

Condition Reports

2000-10766; 2001-03438; 2001-04077; 2001-06402; 2001-01447; 2002-08931; 2001-09556;2002-09618, 2002-10049, 2002-10139; 2002-11045; 2002-9565; 2002-9567; 2002-9583; 2002-9642; 2002-9597; 2002-9659; 2002-9997; 2002-10378; 2002-10312; 2002-10422; 2002-10408; 2002-10990; 2002-10552; 2002-10912; 2002-10901; 20002-10853; 2002-11029; 2002-10997; 2002-11003; 2002-10983; 2002-10997; 2002-11003; 2002-10245; 2002-10518; 2002-9993; 2002-9569; 2002-9890; 2002-9821I 2002-10990;2002-9744.

Inservice Inspection

ENN-DC-126, Revision 1, Steam Generator Degradation Assessment for IP2 RF015 Report No. SG-SGDA-02-09
Industrial Guideline Deviation Approval Sheet
Operational Assessment of IP2 Steam Generator Tubing for Cycle 15
Inservice Inspection Report Proposed Steam Generator Examination Program - 2002 Refueling Outage (2R15)

Steam Generator Eddy Current Testing

ASME Boiler and Pressure Vessel Code Sections V and XI.
NRC Generic Letters 95-03 (Circumferential Cracking of Steam Generator Tubes,

Section 2OS1, Access Control to Radiologically Significant Areas

- RWP 25221, Rev. 1, Modifications on canal transfer cart and on refueling mast
- RWP 25222, Rev. 1, Steam generator primary side work
- RWP 25226, Rev. 2, Outage valve work
- RWP 25234, Rev. 2, Reactor head work including asbestos insulation removal and bare head inspection
- RWP 25235, Rev. 0, Inspection under reactor head
- Procedure SAO-304, Rev. 23, Radiological boundary controls
- Procedure HP-SQ-3.109, Rev. 27, Control of HR, LHR, Special LHR, and VHR Areas
- Procedure HP-SQ-3.801, Rev. 18, Personnel decontamination
- Extremity dose assessment for an individual during reactor cavity close-out inspection and debris removal dated November 11, 2002
- Root cause investigation report for potential unlocked and un-barricaded high radiation area inside vapor containment at the 46-feet elevation (CR-IP2-2002-09618)\
- Root cause investigation report for airborne particulate release in vapor containment resulting in minor facial contamination of forty-nine workers (CR-IP2-2002-10049)
- Health Physics Outage (2R15) Initiatives
- Outage (2R15) Handbook
- RES Self-Assessment Schedule for 2002
- IP-RES-2002-080 Training focused self-assessment, third quarter 2002
- IP-RES-2002-085 INPO AFI Assessment, October 3, 2002
- IP-2002-HP-046 Assessment of radworker training, September 26, 2002
- IP-HPS-2002-048 Assessment of 95-foot hill, September 30, 2002
- IP-WMD-2002-012 Outside RCA Assessment, October 2, 2002
- IP3-LO-2002-00140 RCA assessment of fuel storage building, Unit 3 to Unit 1 walkway, and 95-foot airlock (exterior), September 29, 2002
- IP3-LO-2002-00141 Fourth floor RCA, September 25, 2002

Section 2OS2, ALARA Planning and Controls

- ALARA Review 02-004, Modifications on canal transfer cart and on refueling mast
- ALARA Review 02-010, Steam generator primary side work
- ALARA Review 02-013, Outage valve work
- ALARA Review 02-017, Reactor head work including asbestos insulation removal and bare head inspection
- ALARA Review 02-030, Inspection under reactor head
- In-progress job review (ALARA review 02-013) for outage valve work (RWP 025226) dated November 14, 2002
- Outage (2R15) ALARA reports for November 4, 12, 13, and 14, 2002
- Station ALARA committee agenda for quarterly meeting on December 4, 2001
- Station ALARA committee agenda for pre-outage meeting on October 24, 2002

Section 2OS3, Radiation Monitoring Instrumentation and Protective Equipment

- IP-HPS-2002-044 Random instrument calibration check assessment for first half of 2002, August 8, 2002
- IP-HPS-2002-079 Electronic dosimeter assessment, September 30, 2002

CRDMs

Procedure 83-0051, Rev 1. IP2 Reactor Vessel Head Remote Visual Inspection
Procedure WDI-ET-002, Rev 1. IntraSpect Eddy Current Inspection of J-Groove Welds in Vessel Head Penetrations
Procedure WDI-ET-003, Rev 3. IntraSpect Eddy Current Imaging for Inspection of Reactor Vessel Head Penetrations
Procedure WDI-ET-004, Rev 1. IntraSpect Eddy Current Analysis Guidelines for Inspection of Reactor Vessel Head Penetrations
Procedure WDI-ET-005, Rev 1. RPV Head CRDM Penetrations, Eddy Current Examination for Wastage Detection Procedure
Procedure WDI-ET-008, Rev 0. IntraSpect Eddy Current Imaging for Inspection of Reactor Vessel Head Penetrations with the Gap Scanner
Procedure WDI-UT-010, Rev 3. IntraSpect Ultrasonic Procedure for Inspection of Reactor Vessel Head Penetrations, Time of Flight, Longitudinal & Shear Wave
Procedure WDI-UT-013, Rev 1. CRDM/ICI Ultrasonic Testing Analysis Guidelines

Drawing 6D30089, Rev 1. CRDM Calibration Tube SAP #102902

Condition Reports CR-IP2-2002-10186 and CR-IP2-2002-10052

d. List of Acronyms

AFW	auxiliary feedwater
ALARA	As Low As Reasonably Achievable
AOI	abnormal operating instruction
ASME	American Society of Mechanical Engineers
CCDP	Conditioned Core Damage Probability
CCR	central control room
CCW	component cooling water
CFR	Code of Federal Regulations
COL	check off list
CR	condition report
CRDM	control rod drive mechanism
DBI	design basis initiative
DCP	design change package
ECT	eddy current testing
EDG	emergency diesel generator
FCCH	fuel core and component handling
HRA	high radiation area
I&C	Instrument and Control
ICM	interim compensatory measures
IP2	Indian Point Unit 2
IPEEE	individual plant examination for external events
ISI	Inservice Inspection
kV	kilo-volt
LER	licensee event report
LHRA	locked high radiation area
LTC	load tap changer
NCV	non-cited violation
NDE	non-destructive examination
NLO	non-licensed operator
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OASL	Operations Administrative Step List
OS	occupational safety
PCO	plant check-off list
PI	performance indicator
PM	post maintenance
PT	penetrant Testing
PTO	protective tag out
PWSCC	primary water stress corrosion cracking
PWT	post-work test
RCA	radiologically controlled area
RCS	reactor coolant system
RFO	refuel outage
RHR	residual heat removal
RPS	reactor protection system
RPV	reactor pressure vessel
RV	reactor vessel

RWP	radiation work permit
RWST	refueling water storage tank
SAO	station administrative order
SAT	station auxiliary transformer
SDP	significance determination process
SI	safety injection
SOP	system operating procedure
TFC	temporary field change
TI	temporary instruction
TM	temporary modification
TS	Technical Specifications
TSFPCS	temporary spent fuel pool cooling system
UFSAR	Updated Final Safety Analysis Report
UT	ultrasonic testing
V	volt
vdc	volts direct current
VT	visual test
WO	work order

ATTACHMENT 2

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 re-review during future examinations.

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

The examination was capable of identifying the PWSCC phenomenon described in the Bulletin. The examination was adequate to identify and disposition 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?

One trace deposit of residual boric acid and a few small indications of past boric acid flow 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. Boric acid deposit isotopic analysis showed the age of the deposit to be over 10 years.

The general condition of the head was mostly clean bare metal with some paint and insulation adhesive remaining. The video-taped inspection showed no boron deposits that were considered to result from 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 insulation removal process would have allowed significant boron deposits to be identified and remain for characterization by the visual examination technique used. None 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.

TI 2515/150, Sections 04.03h, 04.04g, 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. One lower-level issue was identified by the inspector in that the procedure for eddy current testing (ECT) did not require eddy current data to be reviewed by a second eddy current analyst. A condition report was issued to have the ECT procedure revised to require data review by a second ECT qualified analyst and applied retroactively.