U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.: 50-293

Report No.: 50-293/89-13

Licensee: Boston Edison Company
800 Boylston Street
Boston, Massachusetts 02199

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: November 20, 1989 - January 15, 1990

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Inspection Summary:

Areas Inspected: Restart staff inspections were conducted to assess licensee management controls, conduct of operations, and the licensee's approach to investigation and resolution of events during the 100% power plateau of the licensee's Power Ascension Test Program and normal operations at full power. In addition, the inspectors reviewed licensee self-assessment activities.

Results: The licensee's critique process overall appears to be functioning in an appropriate manner to aid in event reconstruction, root cause analysis and development of corrective action recommendations (Section 2.3.4). The Recommendation for Improvement (RFI) program appears to be an effective management tool to hear, evaluate and act upon employee concerns and recommendations (Section 6.4).

There appears to be a weakness in the licensee's locked valve program implementation in that two improperly locked valves were found by the inspector on a system walkdown (Section 2.4, UNR 89-13-02).

The area of high radiation area access control is unresolved pending a licensee review for possible programmatic implications of high radiation area access control events (Section 8.0, UNR 89-13-01).

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DETAILS

1.0 Summary of Facility Activities

At the beginning of this report period, the plant was operating at approximately 94% power. The power was limited to less than full power due to a limiting rod control pattern and a lockup of the "A" recirculation pump speed controller.

Following minor modification to the "A" recirculation pump motor-generator (M-G) set speed control circuitry on December 6, 1989, the M-G set tripped with reactor power at about 97% when the generator field breaker opened due to generator field undervoltage. Reactor power stabilized at about 55% of rated power following the transient. Licensee troubleshooting identified a failed resistor in the M-G set voltage regulation circuitry and a degraded resistor in the M-G set speed control circuitry which could have caused the M-G set trip. After replacement of the resistors and testing of additional components, the "A" recirculation pump M-G set was returned to service. Details are provided in Section 2.3.6.

On December 6, 1989, NRC Commissioner James R. Curtiss toured the Pilgrim facility. Commissioner Curtiss was accompanied by his staff and Mr. William T. Russell, Region I Regional Administrator.

During the weeks of December 4, 1989 and December 11, 1989, the NRC conducted an evaluation of the licensee's operator requalification program. The evaluation involved the administration of NRC-prepared operating and written examinations to selected facility licensed operators. Details of the inspection are contained in NRC Inspection Report 50-293/89-14.

At 3:08 a.m. on December 8, 1989, the reactor automatically scrammed from about 95% power on a false low reactor water level signal during calibration of a reactor vessel level instrument. All systems responded properly following the plant trip and associated Group II isolation signal with the exception of a secondary containment damper which indicated partially opened. A redundant damper was verified closed. The scram occurred while Instrumentation & Control technicians were restoring the level instrument to service. When an isolation valve to the instrument rack containing the "A" and "B" reactor level and pressure transmitters was opened, a pressure spike in the common variable leg caused the low reactor water level scram signal. There was no actual low water level condition. Details are provided in Section 2.3.3.

On December 9, 1989, the licensee experienced an isolation of the Residual Heat Removal (RHR) system shutdown cooling suction valves. The action of these two valves going off their full open position actuated a trip of the

RHR system pump. The licensee determined that the isolation of the shutdown cooling suction valves was due to a minor hydrodynamic event actuating the "high" pressure (100 psig) interlock for shutdown cooling. Details are provided in Section 2.3.4.

At 5:26 a.m. on December 11, 1989, the licensee brought the reactor critical. The turbine-generator was synchronized to the grid at 3:15 p.m. on December 12, 1989. The plant reached full power on January 2, 1990. The plant was operating at 100% power at the close of this report period.

On December 14, 1989, the licensee completed the Power Ascension Test Program and submitted their assessment of the Power Ascension Test Program to the NRC in their Final Assessment Report. The report indicated that NRC Confirmatory Action Letter (CAL) 86-10, dated April 12, 1986, and its supplements had been satisfied and requested closure of the CAL.

On January 4, 1990, the NRC Restart Assessment Panel met at the Chiltonville Training Center in Plymouth, Massachusetts. NRC management from Region I, the Office of Nuclear Reactor Regulation (NRR) and the NRC resident staff participated. The Panel received a presentation from the licensee on their assessment of the Power Ascension Test Program. The Panel also reviewed licensee performance during the 75% to 100% power plateau.

NRC inspection activities during this report period were conducted by the onsite Pilgrim Restart Staff. The Pilgrim Restart Staff is composed of the Pilgrim resident inspectors, NRC regional-based and headquarters-based inspectors and an NRC contractor. On December 20-21, 1989 and on January 3 and 5, 1990, Mr. A. Randy Blough, Chief, Reactor Projects Section No. 3A was onsite. On January 3, 1990, Dr. Ronald R. Bellamy, Chief, Facilities Radiological Safety and Safeguards Branch was on-site.

On December 31, 1989, Mr. Antone Cerne assumed the position of Resident Inspector at Pilgrim, replacing Mr. Tae Kim, who has assumed the position of Resident Inspector at the Calvert Cliffs Nuclear Power Station.

The Restart Staff maintained extended shift coverage throughout this report period.

2.0 Operations

2.1 Sustained Control Room Observations

Control room activities were routinely observed during this inspection period to ensure control room staffing was maintained, access to the control room was controlled and operator performance was appropriate to plant configuration and activities in progress.

Control room personnel were alert, attentive and responded appropriately to annunciators and plant conditions. Operator response to the transient caused by erratic operation of the turbine control valve on

December 13, 1989 (Section 4.1) was good. Control room staffing was in accordance with Technical Specifications (TS). Cognizant shift personnel were knowledgeable of plant conditions and ongoing surveillance and maintenance activities. Shift turnovers were adequate. Control room instrumentation was noted to be functioning properly and the inspector noted appropriate tagging for off-normal, deficient and tested equipment. The shift log adequately characterized and adequately documented operating history.

On December 11, 1989, the licensee received the common control rod "overtravel" annunciator panel alarm. Troubleshooting by I&C personnel determined the alarm was caused by a ground on the 06-15 position indicator probe (PIP). Temporary modification 89-35 per procedure 1.5.9, "Temporary Modifications," was performed to disconnect the affected panel connector pin, thereby removing it from the common panel alarm. On December 12, 1989 another "overtravel" panel alarm was received. I&C troubleshooting identified a similar problem (a ground) on the 30-51 position indicator probe. Temporary modification 89-36 was similarly issued to lift the lead. The inspector concluded that licensee corrective actions were adequate in addressing the technical issues from a safety perspective. The control rods remained operable and the "overtravel" panel alarm system remained operable except signals from the 06-15 and 30-51 control rods. The inspector verified that the licensee has other acceptable methods of verifying these two rods do not overtravel. A maintenance request has been issued to repair these during the March outage.

During follow-up to tagging deficiencies documented in Inspection Report 50-293/89-12, Section 2.4, on December 28, 1989, the inspector reviewed the licensee's monthly tagout audit results for December. The licensee's audit was completed on December 21, 1989 utilizing the recently implemented tagout audit surveillance. No deficiencies were found. A subsequent audit of active tagouts conducted by the inspector found no descrepancies. Control room administrative assistants appear to have a thorough understanding of administrative tagout procedures. An internal licensee Quality Assurance Department (QAD) audit is planned for later in January 1990.

The inspector reviewed several representative pre-evolution brief checklists for the period December 10 - 21, 1989. The checklists outline "topics to be considered." The depth of comments contained in the briefing checklist varied and depended on the evolution and the responsible nuclear watch engineer or nuclear operations supervisor conducting the briefing.

From December 26-29, 1989 the inspector observed two pre-evolution briefings, for procedure 8.9.1, "Manual Start and Load Each Diesel Generator," and for procedure 2.2.84, "Local Control of Recirculation Motor-Generator Set." The briefings were attended by the appropriate personnel and sufficiently addressed the purpose of the evolution, expected sequence of events, individual responsibilities, expected results and criteria for terminating the evolution.

During control room observations, the inspector noted that operations or evolutions which interfaced with the control room or affected control room indications were monitored by a second licensed operator. The second licensed operator, normally the on-shift licensed operator designated to monitor the balance-of-plant, was stationed at the appropriate panel in the control room.

The inspector had no further questions in this area.

2.2 Plant Tour Observations

The inspectors routinely conducted plant tours and noted that plant housekeeping and the physical appearance of the plant was generally good. During a plant tour on December 14, 1989, the inspector tested an emergency light (#43R), located across from the hydraulic control unit accumulators in the reactor building, which did not illuminate as required. All other lights tested by the inspector illuminated as designed. The inspector informed the Nuclear Operations Supervisor who noted the inspector's observation and stated that appropriate personnel would be informed for corrective action.

2.3 Review of Plant Events

2.3.1 Inoperable HPCI Turbine Gland Seal Condenser Blower

On November 22, 1989, the licensee declared the High Pressure Coolant Injection (HPCI) system inoperable after the HPCI system turbine gland seal condenser (GSC) blower motor failed to start.

The HPCI system turbine gland seal condenser blower failed to start when its control switch was moved to the start position in order to clear the "HPCI Turbine Exhaust High Drain Pot Level" alarm, per the Alarm Response Procedure. Licensee investigation revealed that the GSC blower motor did not start when the blower's control switch was moved to the start position due to worn motor brushes. The GSC blower motor was replaced and satisfactorily tested. Subsequent visual inspection of the GSC blower motor revealed that one of the two motor brushes exhibited considerably more wear than the other brush. Previously, on August 5, 1989, the HPCI system was declared inoperable when the HPCI system GSC blower failed to start when the blower's control switch was moved to the start position. The licensee determined the cause to be age-related wear of the GSC blower motor brushes. At that time, the motor brushes were replaced. Licensee investigation of the uneven brush wear noted following GSC blower motor replacement is ongoing. The inspector will follow licensee investigation during routine inspection activities. This event was reported to the NRC via the Emergency Notification System (ENS).

2.3.2 Primary Containment Valve Partially Open

During the performance of Temporary Procedure (TP) 89-112, "Manual Insertion of a TIP when Primary Containment Integrity is Required," the licensee determined that the "A" Traversing In-Core Probe (TIP) ball valve was partially open when it was thought to be in the closed position.

On November 15, 1989, the "A" TIP system mechanism was in service to calibrate local power range monitors (LPRM's). When the drive cable and detector for the "A" drive were being withdrawn, the ball valve unexpectedly attempted to close automatically even though the cable and detector had not fully retracted. The ball valve is electrically opened by a solenoid and closed by a spring when the solenoid de-energizes. Investigation by the licensee revealed that the ball valve's actuator solenoid had become de-energized and failed closed onto the cable. Due to primary containment considerations, the licensee manually rotated the ball valve stem to sufficiently open the valve in order to completely retract the drive cable and detector. After retracting the detector, the ball valve was allowed to spring close to what the licensee believed to be the closed position. However, on November 30, 1989 during subsequent troubleshooting of the ball valve and actuator, the ball valve stem was discovered to be distorted, resulting in an offset for the ball valve position such that the valve was not fully closed.

The ball valve's roll pin was found to have an approximately 80 degree rotation from its expected position (i.e., the valve was full open at 10 degrees from the normally closed position). Licensee investigation determined that the cause of the rotation of the roll pin from its expected position was due to a damaged valve stem, possibly due to manual manipulation of the stem to allow removal of the TIP cable and probe from the inserted position on November 15, 1989. The ball valve was subsequently shut and deactivated.

The licensee replaced the ball valve and solenoid actuator while the plant was shutdown on December 11, 1989. In addition, the licensee performed a satisfactory local leak rate test of the valve. The licensee is continuing their engineering analysis of the failure mode of the valve stem.

Since the "A" TIP ball valve is a primary containment isolation valve which impacts containment integrity, as defined by Technical Specifications (TS) 3.7.A.2, the licensee reported this event in LER 89-037. The LER, dated December 30, 1989, appropriately addressed the reporting criteria of 10 CFR 50.73. The safety consequences of this event (one partially open TIP ball valve) are enveloped by a previous BWR owners group and General Electric technical report which assumed the failure of all TIP ball valves to isolate. The report concluded that a design bases accident, concurrent with simultaneous failure of the four TIP ball valves to isolate will result in offsite doses well below 10 CFR 100 limits. Containment leakage would be under 2% containment volume per day with all TIPs unisolated. The report source term assumptions were consistent with NRC Regulatory Guide 1.3 recommendations. Additionally, the report conservatively assumed a standby gas treatment system filtration efficiency of 95%. Therefore, the safety significance of one partially open TIP ball valve is minimal. Further, the TIP shear valve downstream of the ball valve was capable of being manually isolated if an event occurred in which a leakage path from the "A" TIP system was identified.

The inspector considered the licensee's actions to be appropriate and has no further questions, but will review the corrective actions discussed in LER 89-037 as part of routine event evaluation and report closure.

2.3.3 Reactor Scram on a False Low Reactor Vessel Water Level

On December 8, 1989 at 3:08 a.m., the licensee experienced an automatic reactor scram from about 95% power, due to a false low reactor vessel water level signal following calibration of a reactor vessel level indication instrument.

During performance of procedure 8.M.2-2.1.2, "Reactor Level and Pressure Instrument Calibration," Attachment A, and while restoring reactor vessel water level instrument LI-263-59A to service following calibration, the reactor scrammed as a result of a transient in the variable sensing line to the reactor level transmitters (LT-57A and LT-57B). All three level indicators share common variable and reference pressure sensing lines. Level instrument LI-263-59A is a differential pressure type indicator (ITT/Barton) which provides local reactor vessel water level indication in the Reactor Building and is calibrated "wet" quarterly.

Licensee investigation determined the cause of the reactor scram signal to be a minor hydraulic transient that resulted in a false low reactor vessel water level signal. While restoring the indicators to service following calibration, an apparent pressure transient occurred in the variable sensing line upon opening the instrument isolation valve. This pressure transient in the variable sensing line apparently caused reactor vessel water level transmitters LT-57A and LT-57B to sense (falsely) a low reactor vessel level, initiating a reactor scram.

The licensee also considers that the sharp pressure response when opening the isolation (needle) valves could be indicative of wear, possibly related to overtightening. Finally, the other instruments on this RPS rack are Rosemount transmitters. The difference in sensitivity between the Barton and the Rosemount instruments may be such that it is not prudent to valve in and out the Barton instrument while the plant is on-line.

The procedure contains a caution which states that the valving in and out of these instruments could hydraulically affect other instruments which share common sensing lines, that caution should be used, and that sensing line effects on other instruments could result in a scram. The I&C technicians performing the evolution were qualified in the evolution and the technician operating the valves had previously performed the last surveillance. A pre-evolution briefing was conducted and a second reactor operator was stationed at control room panels for this evolution.

The same surveillance test previously had caused a full reactor scram signal with the reactor already shutdown on January 17, 1988. The scram signal occurred when the I&C technician was returning the reactor water level instrument to service following the calibration check. At that time, the licensee determined the cause for the RPS trip signal was procedural inadequacy in that the procedure did not contain sufficient instructions or cautions to alert the technician that air introduced into the sensing lines of local level indicator LI-263-59A during calibration could affect other instruments mounted on the same RPS instrumentation rack (see LER 88-002-01). Air had been used previously to calibrate the level instrument. Previous corrective action was to revise surveillance procedure 8.M.2-2.1.2 to provide additional instructions to personnel for isolating, connecting and disconnecting test equipment and returning the level indicators to service. In addition, to prevent recurrence, the procedure was changed to calibrate using water.

Licensee corrective actions with respect to the December 8, 1989 reactor scram include the following: (a) revision to procedure 8.M.2-2.1.2 to calibrate the local level indicators (LI-263-59A and 59B) only while the plant is shutdown; (b) investigation of possible improvements for calibration of the local level indicators, including possible replacement of the needle type manifold valve(s) with a metering type valve and/or the installation of a pressure tap on the high side of the manifold; and (c) investigation of possible improvement to the procedural valving sequence for removing or returning a local level indicator to service.

During post-trip review, the licensee determined that one of two in-series Secondary Containment System (SCS)/Refuel Floor exhaust ventilation dampers (AON-90 and 91) was identified to have not completely closed. The in-series damper AON-91 closed completely. The licensee concluded that the SCS/Refuel Floor exhaust ventilation damper did not completely close because of rubbing of the damper blades and stationary edge seals. The rubbing resulted from inward flexure of the damper edge seals that occurred because of normal differential pressure developed by the related exhaust fans. The operation of the damper was corrected by pressing the damper edge seals outward in accordance with vendor instructions and satisfactorily re-tested.

Licensee investigation of the cause of the reactor scram, including conduct of the critique was thorough. Proposed corrective actions appear to be appropriate to address concerns relating to preventing recurrence of this event.

2.3.4 Isolation of Shutdown Cooling System and Pump Trip

On December 9, 1989 the licensee experienced an automatic isolation of the Residual Heat Removal (RHR) system shutdown cooling valves MO-1001-50 and MO-1001-47. The action of valves MO-1001-47 and 50 going off their full open position actuated a trip of RHR pump "A." The tripping of the RHR pump "A" is a pump protective feature to prevent operation of the RHR pump without a suction path.

Following the reactor scram on December 8, 1989, the licensee had begun preparations to place the plant in cold shutdown by placing the Shutdown Cooling (SDC) system into operation. The SDC suction piping downstream of the outboard isolation valve (MO-1001-47) and discharge piping up to the loop "A" injection valve (MO-1001-29A) was flushed and vented in accordance with procedure 2.2.19, "RHR Shutdown Cooling Operations." Stroke testing on valve MO-1001-50 was also performed to assure operability of the valve prior to entering SDC, due to previous Furmanite repair performed on the valve. Following completion of venting of the RHR SDC suction and discharge piping, the licensee commenced putting the "A" loop of RHR into SDC mode. Reactor pressure was 5 psig. Following opening of MO-1001-50 and MO-1001-47, the "A" RHR pump was started and the loop "A" injection valve (MO-1001-28A) jogged open to attain flow of about 3200 gpm. Approximately eight seconds after pump start, the licensee experienced an isolation of the MO-1001-47 and 50 valves (Group 3) and an RHR loop "A" pump trip.

Licensee investigation determined the root cause of the actuation to be a hydrodynamic transient in the SDC suction line, causing a brief high reactor pressure signal. This actuated pressure switches (PS-261-23A and 23B) connected to the Recirculation System loop "A" pump suction piping. The licensee considers that the hydrodynamic transient probably resulted from some unvented air in the SDC suction piping, most likely trapped in a section of the suction piping between the inboard and outboard isolation valves (MO-1001-50 and 47) following previous repairs and hydrostatic testing to the MO-1001-50 valve. The setpoint for the pressure switches is arranged as an interlock such that reaching the setpoint of either pressure switch results in a close signal to MO-1001-47 and 50. The trip of RHR pump "A" resulted from the action of valves MO-1001-47 and 50 going off their full open position.

Corrective actions by the licensee included the following: (a) field inspection of accessible SDC suction piping outside the drywell; inspection of this piping, which was considered to be the most susceptible portion of the system for this event, showed no evidence of piping damage or unusual pipe movement; (b) functional testing of related instrumentation, alarms, logic circuitry and valves (MO-1001-47 and 50) was performed satisfactorily; and (c) continued review of potential reconfiguration of existing vents to more effectively eliminate trapped air in the SDC suction piping (Engineering Service Request 88-185 had been previously written to initiate this review).

Licensee review and critique of the SDC isolation was very thorough in its analysis of the event and possible contributing causes. Immediate corrective actions by the licensee were prompt and appropriate. The licensee's critique process appears to be functioning in an appropriate manner to aid the licensee in event reconstruction, root cause analysis and proposal of corrective action recommendations.

2.3.5 Loss of Circulation Water B Pump Lubricating Water Supply

At 8:10 a.m. on December 6, 1989, control room personnel received a report of a severed water line at the intake structure. Immediate investigation revealed that a 2 inch PVC lubricating and gland seal supply line to circulating water pump P-105 B, one of two non-safety related main circulating water pumps, had been severed when an electrical conduit junction cover was dropped onto the piping by an individual working above the pipe. Partial seal water flow was restored within minutes by butting and taping the broken line in place. Pending permanent repair, temporary hose connections were rigged to provide fire main supply to the pump upper and lower bearings and the damaged piping was isolated. Final repair was completed the following day and the system was restored to service. Throughout the event, condenser vacuum was maintained without need for a power reduction.

The inspector present in the control room at the time of the event noted that the licensee initiated timely and effective damage control measures and that the reactor operators immediately initiated continuous monitoring of the appropriate plant parameters concurrent with a review of procedures which might have become applicable (e.g., power reduction, decreasing condenser vacuum) had the circulating water pump been lost.

2.3.6 "A" Recirculation Motor-Generator Set Trip

On December 6, 1989 with reactor power at about 97%, the "A" recirculation pump motor-generator (M-G) set tripped when the generator field breaker opened due to generator field undervoltage. The reactor power stabilized at about 55% of rated power following the transient. Two previous M-G set trips had been experienced (Inspection Report 50-293/89-12, Section 2.3.1).

Licensee troubleshooting identified a failed resistor in the M-G set voltage regulation circuitry and a degraded resistor in the M-G set speed control circuitry which could have caused the M-G set trip. The resistors were replaced, additional components tested and the "A" recirculation pump M-G set returned to service.

Licensee troubleshooting of the M-G set to date consists of the following: All components in the voltage regulator have been checked and/or replaced, the error signal limiting network has been replaced, two circuit boards in the voltage regulator have been changed out, electrical checks have been performed on the generator and exciter field, and the licensee has had the vendor (General Electric) assist in the troubleshooting. The licensee continues to monitor the M-G set. However, the M-G set continued to operate with the scoop tube in local manual control (locked up). Future additional troubleshooting by the licensee may involve testing of the M-G set at or near full M-G set load. However, since this test, if done while the plant is on line, presents the risk of otherwise unnecessary transients, the licensee is considering possible procurement of a load bank to allow troubleshooting activities during a plant outage.

The inspector will review licensee troubleshooting controls, in general during the course of routine inspections.

2.4 Engineered Safety Feature System Walkdown

The inspector performed an engineered safety feature system walkdown of the Standby Liquid Control (SLC) system. The inspection independently verified the status of selected portions of the SLC system and identified equipment conditions and items that might degrade plant performance. This independent verification was performed with the aid of a nuclear plant operator who physically manipulated valves during the walkdown.

The licensee SLC system line-up procedure 2.2.24, "Standby Liquid Control System," was compared to the controlled system drawing (P&ID 249) and the as-built configuration. Valve positions in the line-up procedure matched valve position on the SLC system drawing. However, three valves normally positioned "locked closed" by procedure were not shown to be locked on the system drawing.

The procedure lists two panels, panels C905 and C919, in the control room that should be utilized to verify the standby status of the system. However, panel C919 is not referred to in the subsequent verification steps. The procedure states the SLC system electric heat tracing coil Hi/Lo alarm switches at panel C117 should be set at 110 degrees F/53 degrees F. The inspector found the low alarm set at 51 degrees F as determined by TIS-9058B meter on panel C117. When notified by the inspectors, the licensee reset the alarm to 53 degrees F; the actual minimum permissible boron solution temperature is 48 degrees F.

During the physical walkdown of the SLC system, the inspector identified two areas of concern: (1) adequacy and effective implementation of locked valve procedures; and (2) deficiencies between system labelling and procedure nomenclature.

Two valves, 1101-2A ("A" pump discharge) and 1101-3B ("B" pump suction), specified to be locked open by the procedure were found open but not locked. In one case the valve was clearly unlocked. In the other case the lead wire seal was inadequate and the wire twisted, maintaining the appearance of a properly locked valve.

In response to the inspection findings, the licensee re-performed procedure 8.C.13, "Locked Valve Lineup Surveillance" on January 5, 1990. Licensee investigation determined that the lead wire seal on the one valve was most likely inadvertently knocked off the valve during recent cleaning activities to remove boron precipitation from the valve. The licensee investigation results raises questions regarding the appropriateness of the method used to lock valves. Routine cleaning activities should not degrade system lineup controls. In Inspection Report 50-293/89-10, the inspector previously questioned the appropriateness of the method used to lock valves.

The inspector identified several related concerns regarding the method used to lock valves. These areas included: (a) inconsistent application of the controls concerning valve locking procedures; and (b) use of an inappropriate crimping tool. The inspector found lead wires and pliers on an adjacent SLC system local control panel. An additional area of concern was the discrepancies between actual system labelling and procedural nomenclature. In most instances the breaker or valve description in the procedure does not exactly match the actual breaker or valve label. Some differences were minor, but several procedural descriptions did not correspond with in-plant labelling. The inspector could not accurately identify the in-plant component by the procedural description in the case of several SLC system breakers.

Prior to this inspection, the licensee had already instituted a program to improve its locked valve program. First, the licensee is currently changing existing procedures and surveillances to support the present configuration of the P&ID's. The licensee anticipates completion of this item by February 15, 1990. Second, the licensee is evaluating the adequacy of present P&ID locked valve criteria. This item involves no further action if the criteria are found adequate. However, if the criteria are determined to be inadequate, further criteria will be developed, applied to each safety-related system and a locked valve listing will be generated for each system. Estimated completion date for this item is about September 30, 1990. Finally, the wire seals will be replaced with a new locking device utilizing tie wraps. These tie wraps will not be re-usable, will not require a special crimping tool and will be easy to identify whether they are properly locked. These program changes and review initiatives represent licensee open action items and are being carried on an internal licensee commitment tracking system.

Furthermore, the inspector reviewed administrative controls and procedures regarding sampling of the SLC tank. The results of selected review of samples indicated that sampling was performed in accordance with Technical Specifications (TS) and sample results were within TS requirements. Documentation of sampling results for November and December contained several administrative errors, column changes, and footnotes which were generally minor in nature and did not affect the validity of the sample results. Determination of actual tank water inventory for various samples during the month of December was difficult and compounded by the log recording methods. A recent licensee revision to the record form should help eliminate some administrative errors.

Although all valves and breakers were identified to be properly positioned for the system to perform its safety function, the inspector's findings regarding locking devices demonstrate a weakness in the licensee's locked valve program. This area is unresolved pending further review of ongoing licensee actions to revise their controls (UNR 89-13-02). However, the licensee's actions to upgrade their procedures to support the configuration of the P&ID's, to evaluate locked valve criteria, and to improve their locking devices demonstrate a commitment to improve programs, when necessary.

3.0 Start-up Testing Activities

During ascension from 75% to 100% power, the following start-up testing activities were observed or reviewed.

3.1 Jet Pump Calibrations

The purpose of test procedure 9.17, "Core Flow Evaluation and Jet Pump Calibration," is to ensure that the core and jet pump flow indications are accurate. Total reactor core flow is the sum of the flow rates through the twenty jet pumps. The flow rate through each jet pump is monitored by measuring differential pressure between the jet pump diffuser entrance and a common pressure point in the core entrance plenum. Observation of jet pump calibrations at the 80%, 90% and 100% power levels as well as review of the completed test procedures for these power levels revealed no discrepancies. Discussions with licensee personnel indicated that they were knowledgeable about the procedure. The inspector had no further questions.

3.2 APRM Calibration

Six average power range monitors (APRMs) average the output of 120 local power range monitor (LPRM) amplifiers, provide continuous indication of bulk reactor power level during power operation, and initiate rod blocks and reactor scrams based on reactor power and core flow. The licensee performed procedure 9.1, "APRM Calibration," which applies APRM gain adjustment factors (AGAFs) derived from the process computer core thermal power and actual APRM readings to the APRM channel indications, to ensure that indicated power is proportional to core thermal power.

Observation of the test showed the procedure was correctly followed and review of the procedure indicated no discrepancies.

3.3 Core Performance

Core performance is determined by calculating the Minimum Critical Power Ratio (MCPR) for the core and calculating the Maximum Average Planar Linear Heat Generation Rate (MAPLHGR) for any given fuel assembly in the monitored region of the core. The MCPR is determined by procedure 9.19, "Minimum Critical Power Ratio Evaluation." The MAPLHGR is determined in accordance with procedure 9.22, "Maximum Average Planar Linear Heat Generation Rate." The inspector reviewed the licensee's activities related to core performance and identified no discrepancies.

3.4 Recirculation Scoop Tube Position Readings

The inspector observed the performance of Temporary Procedure (TP) 87-265, "Recirculation Scoop Tube Position Readings." This procedure checks and adjusts the setpoint of the recirculation pump motor-generator set electrical and mechanical high speed stops at less than or equal to 107% rated core flow. TP 87-265, paragraph 10.1 was completed satisfactorily and determined where the MG set high speed stops should be set at less than or equal to 107% rated core flow. Due to the tripping of the "A" recirculation M-G set (Section 2.3.6), paragraph 10.2, "Checking the M-G High Speed Stops," and paragraph 10.3, "Setting Scoop Tube Positioner Electrical Stops," were deferred beyond the end of the Power Ascension Test Program. The first part of the procedure was conducted in a very cautious, deliberate manner. No discrepancies were identified.

3.5 Completion of the Power Ascension Test Program

On December 14, 1989 the licensee completed the Power Ascension Test Program (PATP) at the 75% to full power plateau as described in their August 31, 1988 Pilgrim Nuclear Power Station Power Ascension Program. Inspector observation of the test program at the 75% to full power plateau as well as a sampling inspection of completed PATP procedures, as noted above, indicated that power ascension testing at this plateau was performed satisfactorily. Inspector questions were promptly answered, cognizant personnel were knowledgeable about the test and there were no discrepancies noted.

One operation originally scheduled for the 100% power plateau (the recirculation pump motor generator scoop tube position determination) has not been completed. This operation will be performed at a later date. The licensee revised the Power Ascension Test Program to reflect this change in accordance with the process set forth in the second supplement to Confirmatory Action Letter (CAL) 86-10. The inspector reviewed the licensee's change to the PNPS Power Ascension Program (PATP), dated December 7, 1989. The licensee determined that this change to the PATP did not alter the intent nor lessen the overall effectiveness of the PATP. In addition, in accordance with the requirements for implementing changes to the PATP (second supplement of Confirmatory Action Letter 86-10), a 10 CFR 50.59 safety evaluation was performed. Inspector review of the completed safety evaluation showed it to be satisfactory. The inspector had no further questions.

3.6 Review of Licensee Final Assessment Report

The licensee concluded that their Power Ascension Test Program (PATP) had been successfully completed and submitted their Final Assessment Report (FAR) on December 14, 1989. The report is under a review coordinated by the NRC Pilgrim Restart Assessment Panel; the overall results of the Panel review will be issued by correspondence separate from this inspection report. As an input to the Panel review, the inspectors held onsite discussions with licensee personnel on December 20-21 and reviewed selected FAR back-up material and supporting documents maintained by the licensee. The inspectors also conducted review activities following a licensee management meeting on January 4, 1990 with the NRC Pilgrim Restart Assessment Panel to discuss the FAR. The results of these inspections are documented below and in Sections 5 and 6.

The inspectors concluded that licensee personnel were knowledgeable regarding the FAR contents and bases. Although the content of the FAR is summary rather than detailed in nature, it is well-supported by backup documentation.

During discussions of the FAR, the inspectors asked a variety of detailed questions regarding FAR Appendix A, Assessment of Experience During Implementation of the Restart Plan and the Power Ascension Program. As with other areas of the FAR, licensee personnel were well-versed in the issues involved. In answering the inspectors questions, the licensee made two commitments as follows:

(1) Paragraph 5 b.ii of Appendix A discussed revision of one test procedure to require verification of the steps that involve installation of jumpers or insulating boots. The inspectors questioned whether other procedures would be similarily revised. The licensee responded that the procedure writer's guide will ensure this provision is included in future procedures. Regarding procedures already existing, the licensee committed to make appropriate revisions to the procedure for conducting biennial

procedure reviews to ensure the verification provisions are checked and added as appropriate during the biennial review process.

(2) Paragraph II.D.1 of the main report discusses pre-evolution briefings and indicates that specific signoff provisions for pre-evolution briefings are being put into surveillance procedures as each procedure is revised. The licensee also committed to make appropriate changes to the procedure for biennial procedure reviews. This will ensure the pre-evolution brief signoffs are added to all appropriate surveillance procedures within one biennial review cycle.

Both of the above issues involve procedure enhancements to delineate, in individual procedures, good practices that are already specified in administrative guidance. The licensee's commitments are acceptable.

At the management meeting on January 4, 1990 with the NRC Restart Assessment Panel, the licensee committed to (1) consider their procedure upgrade schedules in FAR Attachment 2 as commitments to NRC and (2) provide the NRC staff with detailed information on the scope of their Procedure Upgrade Program (PUP). The licensee provided the PUP scope, which is appended as Attachment II to the inspection report. No unacceptable conditions were identified. Additional FAR followup inspection activities are detailed in Paragraphs 5.0, 6.4 and 6.5.

Consequently, with licensee's submittal of the licensee's Final Assessment Report, the Power Ascension Test Program was completed on December 14, 1989; NRC staff action regarding acceptance of the program is still pending and will be forwarded by separate correspondence.

4.0 Surveillances

4.1 Routine Surveillance Tests

The following surveillance tests were witnessed or reviewed during this inspection period.

-- Procedure 8.9.1, "Manual Start and Load Each Diesel Generator;"
-- Procedure 2.2.24, "Local Control of Recirculation Motor-Generator Set;" and
-- Procedure 8.A.9-2, "Turbine Test - Monthly."

During performance of Procedure 8.A.9-2 on December 13, 1989, the number 1 turbine control valve responded erratically. Specifically, during the full closure test, it unexpectedly went full open and then fast closed. The plant was at approximately 67% of rated power at the time of the transient. The licensee issued Failure and Malfunction Report (F&MR) 89-481, which identified the erratic control valve performance as a recurring problem. All plant systems responded as designed.

4.2 Cold Weather Protection

An inspection was conducted on December 20, 1989 to determine if the licensee had implemented adequate measures to protect systems important-to-safety from extreme cold weather conditions to ensure operability. The inspector reviewed procedure 8.C.40, "Cold Weather Surveillance," and walked down selected systems to verify the presence and operability of heat tracing, space heaters and insulation.

Inspection of the Station Blackout Diesel Generator enclosure revealed no discrepancies. Space heaters were in operation and the enclosure temperature was adequately controlled. Inspection of the diesel-driven fire pump system, located in the screenhouse, was conducted. Heaters were functioning to control temperature. One of two heat trace wires on the sensing line to the jockey fire pump pressure switch (PS4697) was tagged with a deficiency tag and maintenance request (MR 89-33-349) had been written to repair. Discussion with the licensee regarding disposition of MR 89-33-349 indicated a scheduled work date of 1/15/90 for this MR. However, following this discussion, the licensee re-evaluated this extended date and the existing climatic conditions. Corrective maintenance was expeditiously performed on December 21, 1989. The MR work was closed.

During a review of completed daily surveillance procedures, 8.C.40, the inspector noted surveillances for two days, 12/11/89 and 12/13/89, were missing. A search by the licensee failed to find the missing procedures. Discussion with the shift administrative assistant indicated the crews were confused as to the disposition of the procedure when temperatures were above that required to perform the action steps of 8.C.40. The licensee clarified the requirements with the shift crews. The inspector had no further questions. The licensee's cold weather protection program implementation appears adequate.

5.0 Review of Intersystem Leakage

The inspector reviewed procedures, checked system monitoring activities and evaluated the program of controls established by the licensee in response to reactor coolant system (RCS) leakage into the residual heat removal (RHR) system. Based upon licensee responses to NRC questions (reference: BECo Letter 86-128 dated August 29, 1986) and a Safety Evaluation provided to the NRC (reference: BECo Letter 86-141 dated September 17, 1986) addressing acceptable leakage limits and the determining acceptance criteria, the inspector assessed the licensee efforts to monitor leakage and establish a leakoff path to relieve pressure in the RHR system piping.

Maximum recent leakage, as identified in the 'B' RHR loop, has been estimated to be less than 0.5 gallons per minute (gpm), as measured and calculated in accordance with Procedure 8.5.2.12, "RHR Intersystem Leakage Assessment." The procedural acceptance criteria of 1.0 gpm is consistent the licensee's application of a conservative safety factor based upon 10 CFR 50, Appendix J leakage limits.

The inspector reviewed procedures 8.5.2.10, "RHR Piping Temperature and Pressure Monitoring," and 8.5.2.12,"RHR Intersystem Leakage Assessment," and verified procedural performance, as required. In accordance with the Master Surveillance Tracking Program (MSTP), routine monitoring in accordance with procedure 8.5.2.10 is performed daily and also upon receipt of a "RHR Discharge or Shutdown Cooling Suction High Pressure" alarm in accordance with Alarm Response Procedure, ARP-903L. The inspector checked a sample of the surveillance data sheets for the RHR system temperature surveys for both routine daily monitoring and conditions when the subject alarm was received. In the latter case, the inspector also confirmed the completion of corrective actions for relief of the high pressure conditions using a procedurally controlled leakage path.

The inspector discussed with operations and engineering personnel the normal valve lineup at power, isolating the RHR discharge piping from the RCS. In addition to a check valve in each RHR discharge piping train, two motor operated isolation valves and a relief valve with a setpoint to protect against system overpressurization exist. The inboard isolation valve is normally closed and the outboard one normally open. The inspector examined the system P&ID and checked valve position in the control room, verifying that the normal valve position was consistent with current system configuration documents and that, as documented in memorandum OPS 87-03, a CAL 86-10 commitment to keep the NRC informed of valve position decisions had been met. The inspector also reviewed calibration records for four pressure indicators listed in procedure 8.5.2.10 to be used in the determination of whether in-leakage acceptance criteria, either piping pressure or piping fluid saturation temperature limits, have been exceeded. Evidence of yearly instrument calibration, as required, was available.

During this inspection, the 'B' RHR discharge piping pressure was noted to have exceeded the 350 psig acceptance criterion twice within a twelve hour period. Therefore, in addition to the initiation of corrective action via the pressure relief leakage pathway prescribed in procedure 8.5.2.10, the license was required to implement procedure 8.5.2.12 to assess the actual RHR inleakage. In accordance with procedural steps, closure of a motor operated valve separates the 'A' and 'B' low pressure coolant injection (LPCI) subsystems, placing the plant in a Technical Specification limiting condition for operation. The inspector verified that when the subject valve was closed, control room personnel were cognizant of the LCO requirements and documented the LCO entry (A90-5) in the appropriate log book. Since the procedural requirements for pressure stabilization prior to leakage measurement could not be attained from existing plant conditions, an engineering evaluation was conducted to determine that the one gpm leak rate had not been exceeded. The inspector discussed this decision with the cognizant BECo system engineer and noted that procedure 8.5.2.12 was exited, the LPCI subsystem crosstie valve opened, and the plant removed from the applicable LCO.

Other discussions with BECo system engineering, operations and compliance personnel were held to check the status of commitments made to the NRC in BECo Letter 86-128 in response to CAL 86-10 concerns. In response to questioning, the inspector was provided and reviewed a PNPS calculation sheet (N269) documenting the determination of the acceptance criteria for water leakage past the two isolation valves into the RHR system. The frequency of surveillance monitoring, the history of valve lineup determination and the relationship of the decided leakage acceptance criteria to 10 CFR 50, Appendix J limits were also discussed. The inspector noted that the licensee affirmed their commitment to initiate a controlled reactor shutdown if the acceptance criterion of one gpm inleakage past both isolation valves was exceeded.

However, the RHR Intersystem Leakage Assessment procedure requires a controlled shutdown if leakage is greater than one gpm, calculated at an RHR system pressure of 375 psig, with the normal valve lineup (i.e., only the inboard isolation valve being closed). Thus, the procedure 8.5.2.12 is more restrictive than the licensee's commitment in that it requires a controlled shutdown when in fact other options (e.g., closure of the outboard isolation valve) exist to limit the RHR inleakage below one gpm. Exercising of these other options would require initiation of other Technical Specification action requirements (3.7.A.2), therefore placing the plant in certain low pressure coolant injection system (LPCI) LCO's. But with the procedural corrective action steps, as currently written, these options for mitigating RHR inleakage are not available to the operators. If a minor leakage event occurred, operators would need to develop a procedure change, in parallel with performing shutdown activities, to restore the procedural flexibility. The inspector discussed this inconsistency between the current procedural requirements and the commitments documented in BECo letter 86-128 with engineering and compliance personnel and was informed that a procedural revision was being initiated to allow additional operator actions to respond to RHR inleakage conditions. The inspector evaluated the licensee position and determined that the existing procedure, while restrictive, was acceptable and that no safety concerns were identified. The intended procedural revision will align procedure 8.5.2.12 steps with commitments made to the NRC and provide additional options to the operators upon discovery of excessive RHR inleakage.

Overall, the PNPS program for monitoring and controlling RHR system inleakage appears to provide timely data and adequate information to operations personnel on a routine schedule. Required alarm response is coordinated with procedural performance and corrective action is prescribed in consideration of sufficient margin for the actual leakage limits. Engineering evaluations have been performed to establish conservative shutdown criteria and controlled leakage paths have been evaluated and provided to implement corrective action to relieve RHR system pressure prior to the lifting of the RHR discharge piping relief valve. Both procedures (8.5.2.10 and 8.5.2.12) utilized in monitoring, assessing and controlling RHR inleakage appear to adequately govern actual plant situations and have been used routinely to correct overpressure conditions in the RHR system. With the exception of the issue noted above regarding flexibility in the procedural criteria, no additional questions were raised. The licensee intends to address the flexibility issue with a procedural revision. The inspector identified no violations or unresolved safety concerns and determined that RHR system inleakage at PNPS is being adequately monitored and programmatically tracked and that appropriate corrective actions are being taken as required.

6.0 Follow-up of Previous Inspection Findings

6.1 (Closed) IATI Item 88-21-01, 2.4.7: Formalizing Personnel Qualification Reviews

During the Integrated Assessment Team Inspection (IATI), the team identified weaknesses in the licensee program to ensure adherence to American National Standards Institute (ANSI) N18.1-1971, "Selection and Training of Personnel for Nuclear Power Plants." Specifically, the team observed that selected plant personnel resumes were not being maintained current and that the licensee lacked a formal procedure to ensure consistent application of ANSI position qualification requirements.

Prior to plant restart from the extended outage, the licensee developed an education, experience, and training matrix which was utilized to confirm that qualifications of personnel were consistent with the requirements of ANSI N18.1-1971 for the respective occupied positions. The inspector audited the licensee matrix without deficiency, as documented in NRC inspection report 50-293/88-33.

Additionally, on July 20, 1989, the licensee implemented procedure 1.3.78, "Procedure to Qualify BECO Employee to ANSI Requirements," which established controls to verify candidate qualification consistent with ANSI N18.1-1971 requirements as positions become available. Inspector review determined the procedure contained appropriate instruction and control to ensure future compliance with applicable ANSI requirements. The inspector had no further questions regarding personnel qualification. This item is closed.

6.2 (Closed) IATI Item 88-21-01, 2.4.8: Mission, Organization, and Policy (MOP) Manual

During the IATI, the licensee committed to issue MOP manual policy instructions prior to initial plant restart and to issue organizational position descriptions prior to the completion of the Power

Ascension Test Program (PATP). Previously, as documented in NRC inspection report 50-293/88-33, the inspector reviewed the policy instruction revisions to the MOP manual without deficiency. During the current inspection period, the inspector reviewed the position description portion of the MOP manual. The position descriptions were observed to be well defined and delineated. The inspector had no further questions regarding MOP manual revision. This item is closed.

6.3 <u>(Closed) IATI Item 88-21-01, 2.4.10: Control Room Human Factors</u>

During the IATI, the licensee committed to evaluate control room human factors during the PATP and to provide the NRC with an update of the detailed control room design review (DCRDR) program status. On July 24, 1989, the licensee submitted revision 2 of the DCRDR Program plan to the NRC. The submittal is an extensive report of the DCRDR Program organizational structure, objective, implementation strategy, interface with other programs, and response to NRC concerns. In Section I.F.7 of the plan, the licensee committed to submit a final DCRDR summary report to the NRC by November 30, 1990, which will include a summary of new issues, additional corrective actions, as well as, schedules for implementation. This IATI item is closed.

6.4 <u>Processing of Recommendations and Problems</u>

The inspector reviewed the licensee program of controls for handling BECo employee or contractor observations formally submitted as a Recommendations for Improvement/Investigation (RFI). As described in Nuclear Organization Procedure NOP88A3, such observations may represent a report of a problem, a recommendation for investigation or a recommendation for improvement. The use of such an RFI process, first implemented in September 1988, is not intended to bypass routine corrective action systems or work control programs, but rather to consolidate into one tracking system all reports of potential problems and recommendations relative to those issues for which either the formal corrective action program does not apply or the employee is not certain on which other formal process to use.

The inspector reviewed the latest revision, dated July 26, 1989, to NOP88A3, as well as NOP83A9, discussing the "Management Corrective Action Process" for quality problems identified at PNPS. The inspector interviewed the Staff Assistant to the Plant Manager who administers a Corrective Action Clearinghouse to ensure RFI's are effectively controlled and processed by a centralized program. Other Clearinghouse personnel were interviewed relative to the handling of RFI's for tracking, assignment of ownership and disposition, accountability for response, method of providing confidentiality (if requested), status reporting of open and overdue RFI's and final closure of the issues. It was noted that the Clearinghouse staff is responsible for converting any RFI's which report actual problems into the appropriate corrective action document.

The inspector reviewed the RFI index of open and closed items from September 1989 to January 1990. Actual RFI documents closed near the end of 1989 were spot-checked for evidence of the appropriate manager concurrence for the rejection of recommended ideas, as is procedurally required, and for the tracking of late responses or overdue dispositions. The inspector noted that the Clearinghouse staff utilizes computer tracking for overdue response and disposition handling. Overdue notices to increasingly higher levels of management are used for items that are late for resolution. In all cases, the RFI program has a feedback mechanism to provide final response on the identified problem or recommendation to the RFI originator.

The inspector also examined recent "Open Corrective Action Management Reports" intended to provide to senior BECo managers a status of all open corrective action items and RFI's, sorted by the organizational element to whom the issue is assigned. While the current number of such items is approximately 800 separately tracked issues, the inspector noted that this level represented a reduction of about 200 items from the total items that existed prior to December, 1989. Also, during the sample review of the total of 1364 RFI's initiated in 1989, the inspector determined that very few items would be characterized as allegations. Instead the general nature of the RFI's appeared to be in areas where improvements could be implemented with an even distribution between technical issues and software, non-safety-related recommendations. The inspector confirmed this impression of general RFI content by verifying that very few of the RFI's required conversion to actual corrective action concerns or quality trending items requiring root cause analysis or generic action to prevent recurrence.

The inspector also checked that procedural controls had been established to elevate any RFI of an immediate nuclear safety concern to the Nuclear Watch Engineer (NWE) for immediate evaluation. Any RFI initiated during a backshift period is routinely provided to either the NWE or Shift Technical Advisor (STA) for immediate review and attention.

Overall, the licensee program for the processing of recommendations and problems appears well directed and is procedurally coordinated with the routine corrective action process at PNPS. The use of RFI's to track and disposition potential problems and recommendations has been effective, as evidenced not only by the total number of RFI's submitted, but also by the fact that these issues were, for the most part, not of a nature that required corrective action processing. The inspector verified that procedural controls were established and were being implemented in the handling of RFI's and that BECo management has been kept informed of program results and status. Licensee long term goals to consolidate all recommendations and problem reports into one central tracking system are being appropriately pursued and are attainable. The inspector identified no violations or unresolved safety concerns regarding implementation of the RFI process and considers the overall program to be an effective management tool to hear, evaluate and act upon employee concerns and recommendations.

6.5 Senior Management Surveillance Watch Program

During the Power Ascension Test Program (PATP), the licensee implemented the Senior Management Surveillance Watch Program (SMSWP). The SMSWP was an initiative in which selected senior management personnel maintained a control room and in-plant presence between the hours of 9:00 p.m. and 6:00 a.m. daily to ensure the conduct of backshift operations was consistent with management expectations. Throughout the PATP, the SMSWP members witnessed shift turnovers, pre-evolution briefs, operator response to emerging situations, administrative control of plant processes, as well as observed operator proficiency and professionalism. The SMSWP members submitted assessment reports to the station director following each assignment.

Continuing station management review of the SMSWP reports concluded the program had been successful in achieving the intended results of improved backshift operations. On December 8, by memorandum from the Station Director to the Senior Vice President-Nuclear, the licensee dissolved the SMSWP and returned to normal line management oversight. The memorandum also stated the SMSWP will be periodically reinstated through June, 1990.

Numerous NRC inspection resources have been expended in the independent oversight of backshift activities throughout the PATP. The NRC inspectors have generally observed adequate and improved licensee performance during backshift hours. Inspector review of selected SMSWP reports indicated the SMSWP members performed their functions in a comprehensive and constructive manner. The inspectors also conclude that current backshift performance is sufficient to support return from full-time SMSWP presence to a more routine line management oversight. The inspector had no further questions.

7.0 Maintenance

7.1 Controls over Troubleshooting

Procedure 3.M.1-34, "Generic Troubleshooting and Maintenance Procedure," replaced procedure 3.M.3-8, "Inspection/Troubleshooting-Electrical Circuits" on August 7, 1989. The new procedure (3.M.1-34) provides special instructions for personnel involved in troubleshooting or maintenance activities. Responsibilities of the maintenance division manager, maintenance supervisor, maintenance personnel and quality control engineers are defined. This new procedure provides a flowchart for completing troubleshooting and maintenance activities. A data sheet/activity summary helps ensure the scope of work is well-defined and appropriate reviews are conducted. The inspector concluded that administrative controls with regard to troubleshooting and maintenance are improved through implementation of procedure 3.M.1-34.

8.0 Radiological Controls

Improper High Radiation Area Entry

On December 14, 1989, the licensee informed the NRC of their identification of a posted high radiation area access violation. Specifically, on December 13, 1989, a Radiation Protection (RP) technician observed a fire watch enter and cross the posted high radiation area on the turbine operating deck without proper radiation work permit (RWP) authorization, radiological survey or alarming dosimetry instrumentation. Although the individual was signed in on a continuing RWP, this RWP does not authorize entry into an area that requires a routine or extended RWP. A radiation survey performed along the path travelled by the fire watch showed the highest dose rate encountered to be 80 mr/hr with most areas measuring 2-10 mr/hr.

Subsequent licensee evaluation and investigation determined the following. First, the fire watch was a recently-hired individual with no previous nuclear experience. Licensee interviews revealed that the individual lacked a sound working knowledge of radiological control practices in that (a) the fire watch did not clearly understand the difference between a continuing RWP and a specific RWP; (b) the individual did not clearly understand radiological units and measures and the relative importance to him; and (c) the fire watch had similarly entered the area on previous occasions since he had been trained to use this route. He had been trained on his route when the plant had been shutdown during October/early November and the turbine deck was therefore not posted for high radiation. The licensee considered the root cause of this incident to be the individual's lack of knowledge retention gained in General Employee Training.

Licensee corrective actions included the following: (a) the fire watch's thermoluminescent dosimeter (TLD) and pocket optical dosimeter were read to determine his exposure; (b) all continuing RWP's were placed under the control of radiation protection and personnel were briefed as to the limitations of using RWP's prior to signing in; (c) fire patrol individuals were questioned to determine their working knowledge level of radiological requirements (the licensee determined that these individuals had adequate knowledge in the area of postings and RWP requirements); and (d) training was provided for all contractor fire watch personnel to cover the RWP process.

On September 14, 1989, an incident occurred in which two individuals entered a locked high radiation area without proper authorization and without the required radiological survey or alarming dosimetry instrumentation (Inspection Report 50-293/89-10). In that event, problems with personnel knowledge of high radiation areas were also identified. Based on these two incidents, as a long term action, the licensee recommended in their critique that the station evaluate the current radiological knowledge of other individuals currently assigned as radiation workers. The licensee considers that the results of this evaluation will determine further appropriate correction action.

The licensee was proactive in addressing the issue from a safety perspective and corrective actions were adequate in ensuring immediate radiological safety. Personnel involved in the critique were effective in probing the individual's knowledge of RP controls and the RP staff demonstrated improved self-identification of deficient performance. However, licensee evaluation is not yet completed. Evaluation results are not yet available relative to the following concerns: (a) potential programmatic weaknesses in general employee training; (b) evaluation of other plant personnel knowledge has not yet been fully assessed (other than fire protection); and (c) inspector discussion with other fire protection personnel indicated some individuals felt they did not need to know radiological controls beyond the scope of their current responsibilities. The licensee needs to examine whether plant workers are self-determining the necessary level of knowledge and the possible impact to the radiological control program implementation. Pending licensee review of possible programmatic implications, the recurrent nature of high radiation area access incidents and NRC specialist review of this area, this item is unresolved (50-293/89-13-01).

9.0 Management Meetings

The NRC Restart Assessment Panel met in a teleconference on November 22, 1989. The NRC resident inspectors also participated on this teleconference. The Panel was briefed by the NRC Restart Staff Manager on the status and the conduct of the licensee's Power Ascension Test Program.

An NRC Restart Assessment Panel meeting was held on January 4, 1990 at the Chiltonville Training Center in Plymouth, Massachusetts. NRC management from Region I, the Office of Nuclear Reactor Regulations (NRR) and the NRC resident staff participated. The Panel received a presentation from the licensee on their self-assessment of the Power Ascension Test Program. Attachment III is a copy of the licensee presentation slides. The Panel also reviewed licensee performance during the 75% to 100% power plateau.

At periodic intervals during the inspection period, meetings were held with senior facility management to discuss the inspection, scope and preliminary findings of the resident inspectors. A final exit interview was conducted on January 19, 1990. No written material was given to the licensee that was not previously available to the public.

ATTACHMENT I

INSPECTION REPORT 50-293/89-13

Persons Contacted

R. Bird, Senior Vice President - Nuclear
K. Highfill, Vice President, Nuclear Operations and Station Director
R. Anderson, Plant Manager
D. Eng, Outage and Planning Manager
E. Kraft, Deputy Plant Manager
R. Fairbank, Nuclear Engineering Department Manager
D. Long, Plant Support Department Manager
L. Olivier, Operations Section Manager
N. DiMascio, Radiological Section Manager
J. Seery, Technical Section Manager
G. Stubbs, Maintenance Section Manager
T. Sullivan, Chief Operating Engineer
J. Neal, Security Division Manager
W. Clancy, Systems Engineering Division Manager
B. Sullivan, Fire Protection Division Manager

ATTACHMENT II

BOSTON EDISON COMPANY MATERIAL

PRESENTED TO DESCRIBE THE SCOPE OF

THE PROCEDURE UPDATE PROGRAM (PUP)

AS OF JANUARY 4, 1990

The 1988 Evaluation of Pilgrim Nuclear Power Station by the Institute of Nuclear Power Operations (INPO) found that "Some operations and maintenance procedures lack needed information and contain human factors problems." To address this finding, a procedure upgrade project was established, staffed and funded. The pertinent procedures were indexed and prioritized and they are being tracked through proceduralized review and rewrite processes that correct the deficiencies identified during the original evaluation.

A July 1989 INPO audit of the procedure upgrade project concluded that this effort is resulting in a quality product.

The Boston Edison Company will complete the upgrade of the Pilgrim Nuclear Power Station operations and maintenance procedures in July 1990 and December 1991, respectively. Operations procedures are those used by Operations Section personnel in the performance of plant evolutions and are specifically identified in Attachment 1. Maintenance procedures are those used by Maintenance Section personnel in the performance of corrective and preventive maintenance and are specifically identified in Attachment 2. The procedures upgrade consists of:

- Technical Review

  A walkdown of the procedure, visually reconciling component numbers and nomenclature with that of references, controlled documents, and procedure content and establishing that the procedures' purpose is logically achieved.

- Procedure Rewrite

  A review and rewrite, where necessary, using proceduralized standards for content, style and format.

- Editorial Review

  A proceduralized review, incorporating INPO Good Practice, including human factors' considerations and standardized format.

- Validation

  A walkthrough by an owner-designated individual using a proceduralized checklist to designate that the procedure will be performed as written, achieve its intent and that nomenclature and/or equipment identifications within the procedure match those in the Plant.

- Pre-Approval Review

  Proceduralized consideration for ALARA, Quality Assurance, Quality Control, Emergency Preparedness and nuclear safety reviews.

- Approval

  Final review and approval by Department Manager or Station Director.

Surveillances are included among the operations and maintenance procedures and are being revised to include a Pre-Evolution Brief Checklist. This modification is being incorporated as the surveillance procedures are next upgraded and will be complated by December 1991.

5	PROCEDURE #
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7	1.4.9
8	2.1.1
9	2.1.3
10	2.1.4
11	2.1.5
12	2.1.6
13	2.1.7
14	2.1.9
15	2.1.10
16	2.1.11
17	2.1.12.1
18	2.1.12.2
19	2.1.13
20	2.1.14
21	2.1.15
22	2.1.16
23	2.1.19
24	2.1.22
25	2.1.24
26	2.1.25
27	2.1.26
28	2.1.27
29	2.2.1
30	2.2.2
31	2.2.3
32	2.2.4
33	2.2.5
34	2.2.6
35	2.2.7
36	2.2.8
37	2.2.9
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39	2.2.11
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98	2.2.80
99	2.2.81
100	2.2.82
101	2.2.83
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103	2.2.85
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114	2.2.96
115	2.2.99
116	2.2.100
117	2.2.101
118	2.2.102
119	2.2.103
120	2.2.104
121	2.2.105
122	2.2.106
123	2.2.108
124	2.2.109
125	2.2.110
126	2.2.111
127	2.2.113
128	2.2.117
129	2.2.119
130	2.2.120
131	2.2.123
132	2.2.124
133	2.2.125
134	2.2.126
135	2.2.127
136	2.2.128
137	2.2.132
138	2.2.133
139	2.2.134
140	2.2.135
141	2.2.139
142	2.2.146
143	2.2.149
144	2.2.150
145	2.2.152
146	2.3.1
147	2.4.4
148	2.4.11
149	2.4.13
150	2.4.16
151	2.4.17
152	2.4.19
153	2.4.20
154	2.4.21
155	2.4.22
156	2.4.23
157	2.4.24
158	2.4.25
159	2.4.27

	W
160	2.4.29
161	2.4.30
162	2.4.31
163	2.4.33
164	2.4.35
165	2.4.36
166	2.4.37
167	2.4.38
168	2.4.40
169	2.4.41
170	2.4.42
171	2.4.43
172	2.4.44
173	2.4.45
174	2.4.46
175	2.4.49
176	2.4.51
177	2.4.54
178	2.4.55
179	2.4.57
180	2.4.136
181	2.4.138
182	2.4.141
183	2.4.143
184	2.4.143.1
185	2.4.143.2
186	2.4.144
187	2.4.147
188	2.4.148
189	2.4.149
190	2.4.150
191	5.2.1
192	5.2.2
193	5.2.3
194	5.3.3
195	5.3.6
196	5.3.7
197	5.3.8
198	5.3.9
199	5.3.11
200	5.3.12
201	5.3.13
202	5.3.14
203	5.3.18
204	5.3.19
205	5.3.20
206	5.3.21
207	5.3.23
208	5.3.24
209	5.3.25
210	5.3.26
211	5.3.27
212	5.3.28

	W
213	5.3.30
214	5.3.31
215	5.4.3
216	5.4.6
217	8.1.1.20
218	8.2.1
219	8.2.4
220	8.2.7
221	8.3.2
222	8.3.3
223	8.4.1
224	8.4.2
225	8.4.2.1
226	8.4.6
227	8.4.8
228	8.5.1.1
229	8.5.1.3
230	8.5.1.4
231	8.5.1.5
232	8.5.2.1
233	8.5.2.10
234	8.5.2.12
235	8.5.2.2
236	8.5.2.3
237	8.5.2.4
238	8.5.2.5
239	8.5.2.6
240	8.5.3.1
241	8.5.3.2
242	8.5.3.4
243	8.5.3.6
244	8.5.3.7
245	8.5.3.8
246	8.5.3.9
247	8.5.4.1
248	8.5.4.1-1
249	8.5.4.3
250	8.5.4.4
251	8.5.4.5
252	8.5.4.6
253	8.5.4.9
254	8.5.5.1
255	8.5.5.3
256	8.5.5.4
257	8.5.5.5
258	8.5.5.6
259	8.5.5.8
260	8.5.5.9
261	8.5.6.2
262	8.5.6.3
263	8.5.6.4
264	8.6.5.1
265	8.6.5.2

	W
266	8.7.1.9
267	8.7.2.1
268	8.7.2.6
269	8.7.2.7
270	8.7.3
271	8.7.4
272	8.7.4.1
273	8.7.4.2
274	8.7.4.3
275	8.7.4.4
276	8.7.4.5
277	8.7.4.8
278	8.7.4.9
279	8.9.1
280	8.9.10
281	8.9.11
282	8.9.12
283	8.9.13
284	8.9.14
285	8.9.16
286	8.9.8
287	8.9.9
288	8.10.1
289	8.10.2
290	8.10.3
291	8.10.4
292	8.10.5
293	8.10.6
294	8.A.1
295	8.A.2
296	8.A.9-1
297	8.A.9-2
298	8.A.10
299	8.A.11
300	8.A.12
301	8.A.13
302	8.A.15
303	8.A.16
304	8.A.17
305	8.A.18
306	8.A.19
307	8.A.21
308	8.C.4
309	8.C.6
310	8.C.7
311	8.C.9
312	8.C.12
313	8.C.13
314	8.C.13-1
315	8.C.14
316	8.C.16
317	8.C.17
318	8.C.18

	W
319	8.C.19
320	8.C.20
321	8.C.21
322	8.C.22
323	8.C.23
324	8.C.24
325	8.C.26
326	8.C.28
327	8.C.30
328	8.C.31
329	8.C.32
330	8.C.33
331	8.C.34
332	8.C.35
333	8.C.36
334	ARP-903C
335	ARP-903L
336	ARP-903R
337	ARP-904C
338	ARP-904L
339	ARP-904R
340	ARP-905L
341	ARP-905R
342	ARP-C100L
343	ARP-C100R
344	ARP-C103B
345	ARP-C104B
346	ARP-C1279
347	ARP-C132
348	ARP-C170
349	ARP-C171
350	ARP-C190
351	ARP-C1L
352	ARP-C1R
353	ARP-C20C
354	ARP-C20L
355	ARP-C20R
356	ARP-C236
357	ARP-C2L
358	ARP-C2R
359	ARP-C32
360	ARP-C33
361	ARP-C39
362	ARP-C3C
363	ARP-C3L
364	ARP-C3R
365	ARP-C6
366	ARP-C7L
367	ARP-C7R
368	ARP-CP600L
369	ARP-CP600R
370	ARP-RELAY HSE

7	ELECTRICAL
8	
9	3.M.1-12
10	3.M.3-1
11	3.M.3-10
12	3.M.3-11
13	3.M.3-12
14	3.M.3-13
15	3.M.3-14
16	3.M.3-15
17	3.M.3-16
18	3.M.3-17.1
19	3.M.3-17.2
20	3.M.3-17.3
21	3.M.3-17.4
22	3.M.3-18
23	3.M.3-19
24	3.M.3-2
25	3.M.3-20
26	3.M.3-21
27	3.M.3-22
28	3.M.3-23
29	3.M.3-24.1
30	3.M.3-24.2
31	3.M.3-24.3
32	3.M.3-24.4
33	3.M 3-24.5
34	3.M.3-24.6
35	3.M.3-24.7
36	3.M.3-24.8
37	3.M.3-24.9
38	3.M.3-25
39	3.M.3-25.1
40	3.M.3-27
41	3.M.3-28
42	3.M.3-29
43	3.M.3-30
44	3.M.3-32
45	3.M.3-33
46	3.M.3-34
47	3.M.3-35
48	3.M.3-36
49	3.M.3-36.1
50	3.M.3-36.2
51	3.M.3-36.3
52	3.M.3-36.4
53	3.M.3-37

	Z
54	3.M.3-38
55	3.M.3-39
56	3.M.3-4
57	3.M.3-40
58	3.M.3-41
59	3.M.3-42
60	3.M.3-44
61	3.M.3-45
62	3.M.3-47
63	3.M.3-48
64	3.M.3-49
65	3.M.3-5
66	3.M.3-50
67	3.M.3-54
68	3.M.3-6
69	3.M.3-6.1
70	3.M.3-7
71	3.M.3-8
72	3.M.3-9
73	3.M.4-36
74	8.7.2.2
75	8.Q.3-1
76	8.Q.3-2
77	8.Q.3-3
78	8.Q.3-4
79	8.Q.3-5
80	8.Q.3-7
81	8.Q.3-8
82	
83	
84	MECHANICAL
85	
86	3.M.1-[illegible]
87	3.M.1-14
88	3.M.1-18
89	3.M.4-1
90	3.M.4-1.1
91	3.M.4-10
92	3.M.4-11
93	3.M.4-12
94	3.M.4-13
95	3.M.4-14
96	3.M.4-14.2
97	3.M.4-15
98	3.M.4-15.1
99	3.M.4-17.4
100	3.M.4-18
101	3.M.4-19
102	3.M.4-23
103	3.M.4-24
104	3.M.4-27
105	3.M.4-28
106	3.M.4-34

	Z
107	3.M.4-37
108	3.M.4-38
109	3.M.4-41
110	3.M.4-42
111	3.M.4-44
112	3.M.4-48
113	3.M.4-49
114	3.M.4-5
115	3.M.4-55
116	3.M.4-57
117	3.M.4-58
118	3.M.4-59
119	3.M.4-6
120	3.M.4-60
121	3.M.4-61
122	3.M.4-62
123	3.M.4-63
124	3.M.4-65
125	3.M.4-67
126	3.M.4-68
127	3.M.4-69
128	3.M.4-7
129	3.M.4-71
130	3.M.4-72
131	3.M.4-73
132	3.M.4-74
133	3.M.4-75
13[illegible]	3.M.4-76
135	3.M.4-77
136	3.M.4-8
137	3.M.4-80
138	3.M.4-81
139	3.M.4-82
140	3.M.4-87
141	3.M.4-88
142	3.M.4-9
143	3.M.4-91
144	3.M.4-92
145	3.M.4-93
146	3.M.5-1
147	8.7.2.5
148	8.7.2.9
149	8.7.3.1
150	8.B.24
151	
152	
153	I & C
154	
155	3.M.1-15
156	3.M.1-27
157	3.M.1-28
158	3.M.2-1
159	3.M.2-1.1

	Z
160	3.M.2-1.2
161	3.M.2-10
162	3.M.2-11
163	3.M.2-12
164	3.M.2-14
165	3.M.2-15
166	3.M.2-16
167	3.M.2-17
168	3.M.2-18
169	3.M.2-18.1
170	3.M.2-19
171	3.M.2-2
172	3.M.2-2.1
173	3.M.2-20
174	3.M.2-3
175	3.M.2-4.1
176	3.M.2-4.2
177	3.M.2-5.1
178	3.M.2-5.1.1
179	3.M.2-5.1.2
180	3.M.2-5.1.4
181	3.M.2-5.13
182	3.M.2-5.14
183	3.M.2-5.2
184	3.M.2-5.2.1
185	3.M.2-5.3
186	3.M.2-5.4
187	3.M.2-5.4.2
188	3.M.2-5.4.3
189	3.M.2-5.4.4
190	3.M.2-5.6
191	3.M.2-5.6.1
192	3.M.2-5.6.10
193	3.M.2-5.6.11
194	3.M.2-5.6.12
195	3.M.2-5.6.2
196	3.M.2-5.6.3
197	3.M.2-5.6.4
198	3.M.2-5.6.5
199	3.M.2-5.6.6
200	3.M.2-5.6.7
201	3.M.2-5.6.8
202	3.M.2-5.6.9
203	3.M.2-5.7
204	3.M.2-6.1
205	3.M.2-6.2
206	3.M.2-6.4
207	3.M.2-7
208	3.M.2-7.1
209	3.M.2-7.2
210	3.M.2-8
211	3.M.2-8.1
212	3.M.2-8.2

	Z
213	3.M.2-8.3
214	3.M.2-9
215	8.E.10
216	8.E.11
217	8.E.12
218	8.E.13
219	8.E.13.1
220	8.E.14
221	8.E.19
222	8.E.23
223	8.E.23.1
224	8.E.27
225	8.E.29
226	8.E.29.1
227	8.E.3
228	8.E.3-1
229	8.E.3-3
230	8.E.30
231	8.E.30.1
232	8.E.31
233	8.E.33
234	8.E.36
235	8.E.38
236	8.E.42
237	8.E.47
238	8.E.47.1
239	8.E.48
240	8.E.49
241	8.E.50
242	8.E.51
243	8.E.6
244	8.E.65
245	8.E.65-2
246	8.E.65-3
247	8.E.66
248	8.E.67
249	8.E.8
250	8.E.9
251	8.F.1
252	8.F.18
253	8.F.20
254	8.F.21
255	8.F.26
256	8.F.27
257	8.F.28
258	8.F.29.1
259	8.F.30
260	8.F.31
261	8.F.34
262	8.F.38
263	8.F.4
264	8.F.42
265	8.F.51

	Z
266	8.F.6
267	8.F.8
268	8.M.1-1
269	8.M.1-10
270	8.M.1-11
271	8.M.1-12
272	8.M.1-13
273	8.M.1-14
274	8.M.1-15
275	8.M.1-17
276	8.M.1-18
277	8.M.1-2
278	8.M.1-20
279	8.M.1-21
280	8.M.1-22
281	8.M.1-23
282	8.M.1-24
283	8.M.1-25
284	8.M.1-26
285	8.M.1-27
286	8.M.1-29
287	8.M.1-3
288	8.M.1-3.1
289	8.M.1-3.2
290	8.M.1-30
291	8.M.1-31
292	8.M.1-32.1
293	8.M.1-32.2
294	8.M.1-32.3
295	8.M.1-32.4
296	8.M.1-32.5
297	8.M.1-32.6
298	8.M.1-32.7
299	8.M.1-32.8
300	8.M.1-33
301	8.M.1-4
302	8.M.1-4.1
303	8.M.1-8
304	8.M.2-1
305	8.M.2-1.1
306	8.M.2-1.2.1
307	8.M.2-1.2.2
308	8.M.2-1.3.2
309	8.M.2-1.4.1
310	8.M.2-1.5.1
311	8.M.2-1.5.10
312	8.M.2-1.5.2
313	8.M.2-1.5.3.1
314	8.M.2-1.5.3.2
315	8.M.2-1.5.3.3
316	8.M.2-1.5.3.4
317	8.M.2-1.5.4
318	8.M.2-1.5.4.1

	Z
319	8.M.2-1.5.5
320	8.M.2-1.5.5.1
321	8.M.2-1.5.6
322	8.M.2-1.5.7
323	8.M.2-1.5.8.1
324	8.M.2-1.5.8.2
325	8.M.2-1.5.8.3
326	8.M.2-1.5.8.4
327	8.M.2-1.5.9
328	8.M.2-2.1.10
329	8.M.2-2.1.11
330	8.M.2-2.1.2
331	8.M.2-2.10.1-1
332	8.M.2-2.10.1-2
333	8.M.2-2.10.1-3
334	8.M.2-2.10.1-4
335	8.M.2-2.10.1-5
336	8.M.2-2.10.1-6
337	8.M.2-2.10.1-7
338	8.M.2-2.10.1-8
339	8.M.2-2.10.10
340	8.M.2-2.10.11.1
341	8.M.2-2.10.12
342	8.M.2-2.10.2-1
343	8.M.2-2.10.2-10
344	8.M.2-2.10.2-11
345	8.M.2-2.10.2-12
346	8.M.2-2.10.2-13
347	8.M.2-2.10.2-14
348	8.M.2-2.10.2-15
349	8.M.2-2.10.2-16
350	8.M.2-2.10.2-17
351	8.M.2-2.10.2-2
352	8.M.2-2.10.2-3
353	8.M.2-2.10.2-4
354	8.M.2-2.10.2-5
355	8.M.2-2.10.2-6
356	8.M.2-2.10.2-7
357	8.M.2-2.10.2-8
358	8.M.2-2.10.2-9
359	8.M.2-2.10.3
360	8.M.2-2.10.3-1
361	8.M.2-2.10.3-2
362	8.M.2-2.10.4-2
363	8.M.2-2.10.4-3
364	8.M.2-2.10.4-4
365	8.M.2-2.10.5
366	8.M.2-2.10.7
367	8.M.2-2.10.8.1
368	8.M.2-2.10.8.2
369	8.M.2-2.10.8.3
370	8.M.2-2.10.8.4
371	8.M.2-2.10.8.5

	Z
372	8.M.2-2.10.8.6
373	8.M.2-2.10.8.7
374	8.M.2-2.10.8.8
375	8.M.2-2.10.9
376	8.M.2-2.10.9-1
377	8.M.2-2.2.1
378	8.M.2-2.2.2
379	8.M.2-2.3.1
380	8.M.2-2.4.1
381	8.M.2-2.5.1
382	8.M.2-2.5.3
383	8.M.2-2.5.4
384	8.M.2-2.5.6
385	8.M.2-2.5.7
386	8.M.2-2.5.8
387	8.M.2-2.6.1
388	3.M.2-2.6.3
389	8.M.2-2.6.4
390	8.M.2-2.6.7
391	8.M.2-2.7
392	8.M.2-2.9
393	8.M.2-3.1
394	8.M.2-3.2
395	8.M.2-3.2.1
396	8.M.2-3.3
397	8.M.2-3.6.1
398	8.M.2-3.6.2
399	8.M.2-3.6.3
400	8.M.2-3.6.4
401	8.M.2-4.1
402	8.M.2-4.2
403	8.M.2-4.3
404	8.M.2-4.4
405	8.M.2-4.5
406	8.M.2-5
407	8.M.2-6.1
408	8.M.2-6.2
409	8.M.2-6.3
410	8.M.2-6.4
411	8.M.2-6.5
412	8.M.2-6.6
413	8.M.2-6.7
414	8.M.2-8.1
415	8.M.2-8.2
416	8.M.2-8.3
417	8.M.2-8.4
418	8.M.2-8.5
419	8.M.2-8.6
420	8.M.3-1
421	8.M.3-10
422	8.M.3-11.1
423	8.M.3-11.1.1
424	8.M.3-11.2
425	8.M.3-11.2.1
426	8.M.3-11.3
427	8.M.3-11.3.1
428	8.M.3-11.4
429	8.M.3-11.4.1
430	8.M.3-12
431	8.M.3-13
432	8.M.3-14
433	8.M.3-15
434	8.M.3-16
435	8.M.3-17
436	8.M.3-18
437	8.M.3-2
438	8.M.3-4
439	8.M.3-5
440	8.M.3-6
441	8.M.3-8
442	8.M.3-9
443	8.Q.2-1
444	8.Q.2-2
445	8.Q.2-3
446	8.Q.4-1

ATTACHMENT III

LICENSEE PRESENTATION SLIDES

SELF-ASSESSMENT OF PATP

FINAL

ASSESSMENT

RESTART

AND

POWER ASCENSION

OPERATIONAL EVENTS

PROCESSES TO SUSTAIN IMPROVEMENTS

LESSONS

LEARNED

CONCLUSIONS

Comparison of Results of Operator Requal Exams