Enclosure

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

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Report No.	96-03
Docket No.	50-293
Licensee:	Boston Edison Company 800 Boylston Street Boston, Massachusetts 02199
Facility:	Pilgrim Nuclear Power Station
Inspection Period:	April 7, 1996 through June 2, 1996
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EXECUTIVE SUMMARY

Pilgrim Nuclear Power Station
NRC Inspection Report 50-293/96-03

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers an 8-week period of resident inspection.

Operations

- Operators responded well to the April 19, 1996, automatic scram from 22 percent reactor power which resulted from high turbine vibrations. The nuclear operating supervisor maintained effective command-and-control while placing the plant in a safe and stable condition. Emergency operating, off normal, and system procedures were used appropriately throughout the event. Operators experienced some difficulty in maintaining reactor vessel water level within the prescribed band (+12 to +45 inches) due to a combination of an equipment malfunction and apparent slow operator response. The post trip review team identified a leaking turbine steam sealing pressure relief valve as the cause of a rapid and unexpected pressure decay. Approximately three minutes after the scram, an overheated generator lock-out relay added smoke into the control room atmosphere. Extra operations personnel staged to support outage activities quickly extinguished the overheated relay and cleared the smoke from the control room atmosphere greatly assisting the operating crew. Lastly, an operator work-around condition involving the control rod bottom light indication required the operators to use diverse means to verify all rods were full in. (Section I.01.2)

- Plant restart preparations and start-up activities were very well controlled, indicating effective management involvement. The approach to criticality and subsequent heat-up rate were conservative and well controlled. Operations management and quality assurance oversight was clearly evident. Operators responded generally well to several nuclear instrumentation equipment problems (e.g., SRM and IRMs). Reactor operators missed an opportunity to detect a malfunctioning IRM chart recorder before a half scram condition resulted. Additionally, one minor operator training issue was observed involving the lack of familiarity with the operation of the generator field breaker switch. (Sections I.01.3 and I.01.4)

- Several operator training issues became evident during this period which constitute an inspector follow item (IFI 50-293/96-03-01). (Section I.05.1)

- Licensee Event Report 96-05, dated May 20, 1996, which reported the automatic reactor scram and associated engineered safety feature actuations on April 19, 1996, was closed this period. (Section I.08.1)

Maintenance

- Operator performance was professional during the manual lift test of safety relief valve RV-203-3B and the SSW system surveillance test, with good communications and proper coordination of related activities. In addition, the pre-evolutionary briefing for the lift test was thorough. All activities were conducted in accordance with the applicable procedures and work orders. (Section II.M1.1)

- Mechanics and a maintenance supervisor disassembled the incorrect equipment sump drain line containment isolation valve, working on AO-7011A in lieu of AO-7011B, during limiting conditions for operation (LCO) maintenance. No adverse safety consequence occurred due to the fail close design of the valve which remained closed during the maintenance. This near miss for containment integrity was self-identified. Plant management initiated timely and meaningful short term corrective actions such as convening a critique, initiating a maintenance night order stressing component identification and self checking, and holding feedback sessions with maintenance workers. The failure to follow the work package instructions was treated as a **non-cited violation** considering the proper short term corrective actions.

  However, limited progress was made by the end of this inspection period in implementing longer term corrective actions. The draft human performance enhancement system (HPES) report completed by maintenance personnel did not address important human performance issues that were identified at the critique. For example, the pre-work area maintenance supervisor inspection, adequacy of lighting, schedule pressure and review of incorrect replacement parts were not evaluated. These shortcomings in the draft HPES report existed 60 days after the event. Subsequently, plant management initiated an issue team to re-perform the detailed root cause evaluation to fully evaluate all human performance aspects of this event. The longer term corrective actions, including the root cause evaluation, will remain as an unresolved item **(UNR 50-293/96-03-02)** pending NRC review of the issue team report. (Section II.M4.1)

- The outage maintenance activities were well planned and controlled. Plant management placed special emphasis on effective use of procedures and doing the job right, the first time. For example, electricians stopped work to obtain an important procedure change involving the recirculation pump motor generator set electrical brushes. Strong supervisory oversight of the recirculation pump seal cartridge placement was evident. Also, an NWE informed plant workers, in advance, of changing the mode switch position so that drywell workers could be informed of the impending noise and the change in dose rates. (Section II.M5.1)

Engineering

- Engineering personnel and management closely monitored the degradation of scram solenoid pilot valve (SSPV) exhaust diaphragms by the collection and analysis of scram time data during this period. Based on this data, no immediate operability issues existed. A temporary procedure was developed to gather scram time data and determine corrective actions. The reactor engineering procedure was thorough and appropriately incorporated engineering's recommendations. Also, BECo communicated effectively with the Regulatory Response Group (RRG) to determine applicable plant-specific slow rod acceptance criteria. Although the licensee's adopted actions differed from the timing frequency and slow rod criteria recommended by the RRG, the justification and overall method for determining potential degradation were reasonable. BECo developed an appropriate temporary procedure, acceptance criteria, and corrective action plan. In addition, BECo was in frequent contact with the industry to remain current on development of a permanent solution to this generic boiling water reactor issue. This item is closed (IFI 50-293/96-01-03). (Section III.E8.1)

Plant Support

- The exposure results for two significant outage work activities inside the drywell, replacement of the mechanical seal cartridge on the "A" recirculation pump and replacement of the pilot assembly for RV-203B, closely matched the planned ALARA exposure goals. Initiatives such as using remote high resolution cameras to monitor recirculation pump work, detailed pre-planning, and the use of temporary shielding contributed to this positive performance. The actual total outage dose of 13.03 Rem for planned work activities was less than the planned outage dose of 13.46 Rem. The work hour estimates supplied by maintenance and planning and used by ALARA for the recirculation pump and RV-203B exposure estimates were generally three times greater than the actual time required to complete the jobs. This potential weakness in maintenance work hour estimates is an inspector follow item (IFI 50-293/96-03-03). (Section IV.R1.1)

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REPORT DETAILS

Summary of Plant Status

Pilgrim Nuclear Power Station (PNPS) began the period operating at approximately 100 percent rated core thermal power. On April 18, 1996 operators reduced power to approximately 50 percent to perform a thermal backwash of the main condenser and then continued to reduced power for a planned five day maintenance outage. During the power reduction on April 19, at approximately 22 percent power, an automatic reactor scram occurred due to a load rejection which resulted from high turbine vibration. Following the planned outage, operators brought the plant to critical at 4:41 a.m. on April 24. The reactor mode switch was taken to RUN at 3:47 p.m. and the generator was synchronized to the grid at 11:26 p.m. that night. Reactor power was maintained at approximately 28 percent until 6:30 a.m. on April 25 to effect further component repairs. The unit reached 100 percent power on April 26. On April 28 power was reduced to approximately 60 percent to perform a planned rod pattern adjustment and rod exercising. Reactor power was returned to 100 percent on April 30, where it remained through the end of the period.

On April 19, 1996, operators made a formal notification (Event Number 30321) to the NRC headquarters operations officer to report the unexpected actuation of the reactor protection system (initiates a reactor scram) due to a turbine generator trip which was caused by high vibration and the resultant activation of primary containment isolation system Groups 1, 2, and 6, during the scram recovery. The report was made pursuant to 10 CFR 50.72(b)(2)(ii). This event is discussed in Section I.01.2 of this report.

I. OPERATIONS

01 Conduct of Operations[1]

01.1 General Comments (71707)

Using Inspection Procedure 71707, the inspector conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety conscious. During tours of the control room, the inspectors discussed any observed alarms with the operators and verified that they were aware of any lit alarms and the reasons for them. Any anomalies noted during tours were discussed with the nuclear watch engineer (NWE). Operator performance of a manual lift test of safety relief valve RV-203-3B after maintenance was professional. Good communication and coordination was evident during this activity. Other specific events and noteworthy observations are detailed in the following sections.

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[1]Topical headings such as 01, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

01.2 Automatic Reactor Scram Due to High Turbine Vibrations

a. Inspection Scope (71707, 93702)

On April 19, 1996, at 10:16 a.m., an automatic reactor scram occurred from 22% reactor power when the main turbine tripped due to high vibrations. At the time of the scram, a plant shutdown was in progress to facilitate a planned outage to repair a leaking safety relief valve (SRV) and a leaking recirculation pump mechanical seal. The inspector was in the control room at the time of the event and observed immediate operator and equipment response to the scram, including operator response to annunciators and use of emergency operating procedures (EOPs).

Following the scram, the inspector attended the event critique during a deep back shift inspection; reviewed the licensee's post-trip report, plant computer printouts and traces, corrective actions taken for the anomalies noted during the event, and event notification and subsequent licensee event report; and discussed the event and corrective actions with pertinent licensee personnel to assess overall response to the April scram. The NRC issued Preliminary Notification (PN) PN1-9624 on April 22 to describe the event and anomalies experienced. The inspector also participated in an April 22 conference call between NRC staff and Boston Edison Company (BECo) senior management to discuss the event and observed anomalies.

b. Observations and Findings

On the morning of April 19, operators were in the process of shutting the plant down for a planned maintenance outage when an alarm for high turbine vibration was received in the control room. The inspector observed operators attempt to reduce turbine load to clear the alarm per procedure 2.4.46, Turbine Bearing Malfunction, per the alarm response procedure. Approximately three minutes later the reactor automatically scrammed due to the turbine trip - reactor trip function in effect at greater than approximately 20 percent power. At the time of the scram, the reactor was at approximately 22% power and one reactor feedwater pump was in operation in single element (reactor water level) control. Reactor pressure was 944 psig and reactor narrow range water level was +26 inches.

Event Chronology

The inspector developed the following event chronology from the plant computer automatic sequence of events printout, computer traces, operator logs, and discussions with plant personnel. The event time data is in the format hours:minutes:seconds.fraction of seconds, and is normalized to the time when the reactor scram signal was received at 10:16 am. The values in brackets are the setpoints for the alarm/isolation. Approximately three minutes before the scram, turbine bearing high vibration alarms were received for main turbine bearings 5 and 6.

0:00:00.000 Scram due to turbine control valve fast closure following turbine load rejection due to turbine bearing high vibration
0:00:07.730 Enter EOP-1, Reactor Pressure Vessel (RPV) Control (entry condition: Reactor water level < +12 inches, actual initial low level +9)
0:00:07.750 Primary Containment Isolation System (PCIS) Group 6 (RWCU) PCIS Group 2 (Radwaste, vent and purge, Reactor Building Isolation System (RBIS) initiated) (Both Groups isolate on a low level of +12 inches)
0:00:28.090 Reactor low water level cleared
0:00:41.770 Tripped last feedwater pump (indicated level on control room strip recorder 23-27")
0:02:04.450 PCIS Group 1 (Main Steam Isolation Valves) from high reactor water level (+48 inches)
0:03:00.000 Fire Alarm for control room panels, smoke in control room from turbine lockout relay failure
0:14:00.000 Water level reaches +60 inches, maximum level during event
0:16:00.000 Exit EOP-1, enter EOP-2, RPV Control: Failure to Scram (Entry condition: All rods not verified at or beyond 02)
0:32:00.000 Open "C" SRV for pressure control
0:34:00.000 Close "C" SRV
0:35:00.000 HPCI inservice for pressure control - full flow test lineup
0:47:00.000 HPCI removed from pressure control
0:50:00.000 Enter EOP-3, Primary Containment Control (Entry condition: Torus temperature > 80 degrees)
0:58:00.000 HPCI inservice for pressure control
1:00:00.000 HPCI isolated on high water level (+45 inches)
1:01:00.000 HPCI in pressure control
1:07:00.000 Open "D" SRV for pressure control
1:08:00.000 HPCI isolated on high water level
1:12:00.000 Close "D" SRV
PCIS Groups 2, 6 isolations (actual level dropped to -5")
Exit EOP-2, enter EOP-1 (Reactor determined to remain shutdown)
1:14:00:000 HPCI inservice for pressure control
1:34:00:000 MSIVs opened
1:59:00:000 Exit EOP-1
Controlled cooldown in progress, exited EOP-3

Root Cause/Operator Actions/Plant Response/Anomalies

Overall operator response to the scram was good. The Nuclear Operating Supervisor (NOS) entered the appropriate EOPs and maintained effective command-and-control during the event. Nonessential personnel were cleared from the control room and frequent plant briefs were given to keep control room personnel aware of the changing plant conditions. Operators correctly entered EOP-1, Reactor Pressure Vessel (RPV) Control, and EOP-3, Primary Containment Control, as required by plant conditions. These EOPs are expected to be entered for a scram with MSIV closure. However, operators entered EOP-2, RPV Control: Failure to Scram, not typically entered for a scram, because two control rods could

not be confirmed at or beyond position 02. (Additional details are discussed below.)

The scram was initiated when valid high turbine shaft vibrations sensed at bearings 5 and 6 caused a turbine trip. During the last refueling outage (April-May 1995), BECo replaced both low pressure turbines with boreless monoblock rotors that inherently use closer tolerances making the machine more susceptible to "rubs" between the moving blades and stationary diaphragms. It was these rubs which caused the high turbine vibration. In response, the licensee lowered the turbine vibration alarm setpoint and increased the vibration trip setpoint to allow increased operator response time to avoid a future plant transient. (Turbine startup during plant restart was carefully controlled as discussed in Section I.01.4.)

After the scram, operators experienced difficulty maintaining vessel water level within the EOP-prescribed band of +12 to +45 inches. The operations training policy is to control level within +20 to +40 inches during the initial phases of a transient. Immediately after the scram, reactor water level reached a low of +9 inches, well above the top of active fuel; a level below +12 inches is the entry condition for EOP-1. A water level shrink to this level is expected after a scram. The expected primary containment isolation system (PCIS), Group 2 - radwaste and reactor building isolation system (RBIS) and Group 6 - reactor water cleanup (RWCU) occurred. Approximately two minutes after the scram reactor vessel water level unexpectedly reached +45 inches which caused the primary containment Group 1 isolation [main steam isolation valve (MSIV) closure], complicating plant recovery. In addition, while operators were attempting to control reactor pressure using the high pressure coolant injection (HPCI) system and safety relief valves (SRVs), an unexpected PCIS Group 6 isolation occurred on low level when the SRV was closed. This condition isolated the reactor water cleanup (RWCU) system which was being used for reactor vessel level letdown to the condenser. Also, during this time period HPCI isolated twice due to high reactor vessel water level.

Shortly after the scram, a turbine lock-out relay, located in one of the control room panels, failed to actuate, overheated and burned adding smoke into the control room atmosphere. Operators quickly responded to the fire alarm and extinguished the smoldering relay. The light smoke had no adverse affect on operator performance. Subsequently, operators stabilized plant conditions and exited the EOPs.

Operators made the required formal notification (Event Number 30321) to the NRC headquarters operations officer to report the unexpected actuation of the reactor protection system (initiates a reactor scram) due to a turbine generator trip which was caused by high vibration, the resultant expected activation of PCIS Groups 2 and 6 and the unexpected PCIS Group 1 isolation which occurred during the scram recovery described previously. The report was made pursuant to 10 CFR 50.72(b)(2)(ii).

Boston Edison Company (BECo) established a post trip review team to review the cause of the event and any equipment performance issues. The inspector attended the critique held in accordance with procedure 1.3.63, Conduct of Critiques and Incident Investigations, during deep backshift on April 20. The purpose of the critique was to gather and evaluate facts, ensure the plant was in a safe condition, and determine immediate corrective actions. The critique was attended by appropriate personnel including the operators who were in the control room at the time of the event. Discussions were open and detailed information was obtained. The plant was verified to be in a safe condition and all immediate corrective actions were verified complete.

Unexpected MSIV Isolation Following Scram

Approximately two minutes after the scram, reactor vessel water level unexpectedly swelled to +45 inches which caused the primary containment Group I isolation (MSIV closure). Reactor vessel water level reached a maximum of +60 inches approximately 14 minutes into the event. Although some swell of the reactor water level is expected due to the increase in void fraction as pressure is reduced, the swell experienced during this event was not anticipated.

The BECo post trip review team identified a rapid pressure decrease, of approximately 100 psig, which occurred in this time period. The licensee examined the possibility of a stuck open bypass or safety relief valve and found none. Since this pressure decrease was terminated after the MSIVs closed, the post trip review team searched for a steam leak downstream of the MSIVs and upstream of the turbine stop valves. BECo determined that steam leaking from the turbine steam sealing pressure relief valve, PRV-3197, caused this additional pressure reduction. The degradation of this valve had previously been identified and was scheduled for maintenance during the April maintenance outage. In order to confirm this assumption, BECo ran test cases on the simulator. The inspector reviewed and discussed this data with operations personnel. Although the exact amount of steam loss through the PRV could not be predicted and, therefore, the simulated conditions could not exactly replicate actual conditions, the simulation did show a 10 percent increase in the swell. The combination of normal level swell, the rapid pressure decay due to the leaking PRV, and the reactor water level when the last reactor feed pump was tripped caused the increase in water level beyond the PCIS Group 1 setpoint. Operator performance cannot be ruled out as a contributor for this anomaly. BECo training will be revised to enhance operator performance during low power scrams (see Section I.05.1).

During the maintenance outage, the Group 1 technical specification (TS) isolation setpoint was raised from +48 to +55 inches. BECo previously received NRC approval of TS Amendment #164 and a plant design change to this setpoint was planned for this outage. Although this increase in setpoint would not have prevented the MSIV isolation in this event due to the leaking PRV, this modification will allow a wider operating water level control band in the future.

Control Rod Bottom Lights Not Illuminated After Scram

Operators entered EOP-2, RPV Control: Failure to Scram, after all control rods could not be confirmed at position 02 or beyond. Immediately following the scram, approximately 48 of the 145 control rod bottom lights were not lit. These lights, located on the full core display on Panel 905 in the control room, provide positive indication of control rod position. When these lights are not illuminated, operators must use diverse means to verify all rods are in. One method uses a computer printout for rod positions. Operators appropriately used this method; however, the printout indicated unreliable information for two of the 48 rods. The other 46 rod bottom lights were not lit due to a common boiling water reactor (BWR) condition concerning a reduced magnetic flux at the position indicating switch following a reactor scram. Approximately 16 minutes after the scram, after reviewing this computer information, operators entered EOP-2, commonly known in the industry as the anticipated transient without scram (ATWS) procedure. ATWS indicates that a transient has occurred which should have caused a scram but a scram did not occur. After replacing the burnt out rod bottom light bulb for one of the remaining two rods, operators had positive full-in indication and satisfied the exit condition for EOP-2.

The inspector noted that operator entry into EOP-2 was somewhat slow. The operations department manager stated that it is not normally expected that operators will take sixteen minutes to enter EOP-2. During the time operators were using diverse means to verify rod positions, as allowed by the EOP, the inspector noted that they were aware that reactor power was indicating on the intermediate range nuclear instrumentation demonstrating that the reactor was shutdown and no actual ATWS condition existed. The inspector discussed management expectations with the operations department manager who agreed that although it is not expected that such a time delay would exist, operators used their knowledge of the plant to decide whether entry into EOP-2 was required.

The lack of rod bottom light indication following a scram has occurred before at PNPS. The inspector questioned whether this issue was tracked as an operator workaround in the licensee's compensatory measures log and found that it was not. Although there is no procedural requirement for this log, items listed in it are generally highlighted to be repaired to limit the burden placed on operators. (A procedure to govern the use of the log is currently in development.) Operations management agreed that although there is no guarantee this condition would have been resolved before the scram had it been added to the compensatory measures log, it is certain that a more timely resolution would have begun. The inspector noted that the item has since been added to the log to highlight the condition.

A few hours after the reactor scram, approximately 46 of the 145 total control rods still did not have full-in position indication due to a generic BWR issue. The process computer and 4X4 control rod display, which receive full-in signals from reed switches that are redundant to

the full-in position light reed switches, can also be used to determine whether rods are full in. Pilgrim operators used both of these methods during the event. General Electric issued Service Information Letter (SIL) No. 532, dated 3/27/91, that recommended a hardware change to avoid temporary loss of full-in indication. At that time BECo determined that the modification could not be used at PNPS because it would interfere with outputs to the plant computer. An alternative design was developed by BECo but later rejected because it would mask failed switches awaiting repair. The licensee is evaluating possible design changes including a modification to the rod worth minimizer (done at Brunswick) to provide operators with an "all rods in" message if all rods have passed position 02. Problem Report 96.9206 was issued to document the problem and determine corrective actions. At the exit meeting, the Vice President of Nuclear Operations confirmed that a modification would be made to correct this condition.

High Pressure Coolant Injection (HPCI) System Declared Inoperable

During the recovery from the scram, the HPCI system was run in the test return mode to assist in reactor pressure control. In this mode, the HPCI system takes a suction from the condensate storage tank (CST) and discharges back to the CST. Because the HPCI pump is powered by a steam driven turbine, running the system in this configuration uses reactor steam to depressurize the reactor without discharging water into the reactor coolant system.

During initial operation of the system, the operator attempted to lower the HPCI discharge pressure in accordance with procedure 2.2.21.5, HPCI Injection and Pressure Control, to reduce reactor cooldown rate. After opening the test return valve, HPCI discharge pressure did not decrease as expected. Pump discharge pressure was approximately 1100 psig with reactor pressure at 800 psig. The operator took manual control of the system at that time and reduced flow using the flow controller. The system responded appropriately with flow, pressure, and turbine speed decreasing accordingly. When the system was secured from pressure control service for the first time, the system engineer was called and discussed the anomalous discharge pressure with the operator. HPCI was used for pressure control throughout the scram recovery and was declared inoperable after it was no longer needed for pressure control. Tracking Limiting Condition for Operation (LCO) T96-71 was appropriately entered; an active LCO was not required since HPCI is not required by TS to be operable when the reactor is shut down. PR 96.9195 was generated to investigate the observed HPCI operation.

The investigation of the discharge pressure included the removal of the test flow restricting orifice to check for blockage and stroking of the flow test valves. No blockage was found and the valves stroked and operated properly. The root cause of the inability to reduce pump discharge pressure by throttling the test return valve was the design of the restricting orifice. The operator did not realize this limitation because the simulator is not modeled to reflect this system characteristic.

The inspector verified that the procedure was enhanced to provide instruction to reduce the discharge pressure using the flow controller in conjunction with the discharge valve, as necessary. In addition, discharge pressure data for the stroking of the test valve will be obtained to provide information to the training center so the simulator model can be updated.

c. Conclusions

Operators responded well to the April 19, 1996 automatic scram from 22 percent reactor power which resulted from high turbine vibrations. The nuclear operating supervisor maintained effective command-and-control while placing the plant in a safe and stable condition. Emergency operating, off normal, and system procedures were used appropriately throughout the event. Operators experienced some difficulty in maintaining reactor vessel water level within the prescribed band (+12 to +45 inches) due to a combination of an equipment malfunction and apparent slow operator response. The post trip review team identified a leaking steam plant relief valve as the cause of a rapid and unexpected pressure decay. Approximately three minutes after the scram, an overheated generator lock-out relay added smoke into the control room atmosphere. Extra operations personnel staged to support outage activities quickly extinguished the overheated relay and cleared the smoke from the control room atmosphere greatly assisting the operating crew. Lastly, an operator work-around condition involving the control rod bottom light indication required the operators to use diverse means to verify all rods were full in.

There were no safety consequences due to the lack of rod bottom light indications following the scram as all rods were inserted and the operators were eventually able to determine rod positions. However, this condition was an operator workaround which required the operator to spend more time than usual verifying rod positions. The organization was not completely effective in proactively identifying this condition as a compensatory measure and adding it to the compensatory measure log, potentially forcing a more timely solution.

01.3 Plant Restart Preparations and Reactor Start-up

a. Inspection Scope (71707)

A review was performed to determine the plant readiness for restart and operator performance during plant restart.

b. Observations and Findings

Near the end of the outage, the inspector attended a nuclear managers committee (NMC) meeting that reviewed the plant readiness for restart. The NMC evaluated various outage related issues related to restart. For example, any work scheduled but not performed was reviewed. Department managers made verification signatures indicating items in each area were completed. The inspector monitored the approach to criticality which

was well controlled by reactor operators. A heat-up rate was established well below the TS limit of 100 degrees per hour as specified in TS 3.6.A. Extensive operations management and quality assurance oversight was evident during back shift hours.

Several nuclear instrumentation (NI) equipment issues hindered the start-up. First, start-up was initiated with one inoperable source range monitor (SRM) which is allowed by TS; however, this allows less tolerance for another emergent SRM problem. Secondly, a half scram condition occurred during start-up when a chart recorder pen for the "C" intermediate range monitor (IRM) power level did not respond causing operators not to range-up the IRM in time to prevent a half scram. Operators quickly responded and cleared the half scram condition by ranging up the "C" IRM. The inspector noted that the subject chart recorder had a work request tag, dated 1/13/96, indicating that a gear was stripped. The assistant operations manager informed the inspector that operators missed an opportunity to identify the stuck pen and avoid the half scram condition. Accordingly, operations department management plans to present this lesson learned during the next plant status update meeting held with operating crews during the training week. Lastly, operators noticed improper response of the "B" and "F" IRMs which did not respond as expected to increasing power levels. Operators performed the required actions specified by TS Table 3.1.1, Note 1. The "B" IRM was bypassed using the toggle switch. Engineering evaluated the anomalous behavior of the "F" IRM concluding that the IRM performance was degraded but operable. This was documented in an engineering evaluation for Problem Report 96.9213. After these conditions were evaluated, the start-up activities recommenced.

The inspector observed that operators responded effectively to each NI problem by stopping start-up, evaluating and implementing TS actions, initiating problem reports and obtaining engineering review. A lessons learned meeting held after the outage identified that improvements are needed in the maintenance of NI.

c. Conclusions

Plant restart preparations and start-up activities were very well controlled indicating effective management involvement. The approach to criticality and subsequent heat-up rate were conservative and well controlled activities. Operations department management and quality assurance oversight was clearly evident. Operators responded generally well to several nuclear instrumentation equipment problems (e.g., SRM and IRMs). However, reactor operators missed an opportunity to detect a malfunctioning IRM chart recorder, which had a work request tag attached indicating a stripped gear problem since January 13, 1996, before a half scram condition resulted.

01.4 Turbine Startup

a. Inspection Scope (71707)

During the startup following the April maintenance outage, the inspector monitored the turbine startup including initial turbine roll; turbine acceleration and vibration monitoring; overspeed trip test; main generator voltage regulator adjustments; and generator synchronization. All activities associated with the turbine startup were performed in accordance with Temporary Procedure (TP) TP96-014, Operational Guidance for Turbine Vibration Limits and Trips During Startup, Rev. 0, dated April 22, 1996. The BECo staff and General Electric (GE) service representatives closely monitored turbine acceleration through the critical speeds to ensure no turbine rubs occurred and that turbine vibrations remained within specified operating limits while the turbine high vibration trip function was disabled, per TP96-014.

b. Observations and Findings

The inspector observed proper operator use of TP 96-014 and its reference documents. The pre-evolutionary briefing was good, particularly the discussion of anticipated and worst case turbine response by the GE service representative. Personnel involved with turbine startup activities and those individuals providing oversight functions were attentive and professional in their conduct. The turbine roll and synchronization was conducted without significant problems. The highest turbine bearing vibrations were between 6-7 mils at a turbine speed of approximately 1065 rpm. This vibration was attributed to the critical speed of the generator. A couple of attempts were necessary to flash the generator field, but this was not atypical. One minor operator training problem occurred involving the electrical panel operator's lack of familiarity with the functioning of the generator field breaker switch. (The operator did not initially realize that the switch must be pulled and turned to trip the breaker.)

c. Conclusions

Observations of the turbine startup activities identified good procedural usage and attentive and professional conduct by the staff in the control room. One minor operator training issue was observed involving the lack of familiarity with the operation of the generator field breaker switch.

05 Operator Training and Qualification

05.1 Operator Training Issues Related to the April 19 Scram and Subsequent Startup

a. Inspection Scope (71707)

During the review of the April 19, 1996, reactor scram, the inspector noted potential training related issues involving the control of reactor

vessel water level following the scram, and operator training on HPCI performance during pressure control activities. The inspector questioned operations and training personnel to determine what corrective actions were planned for these areas.

In addition, operator unfamiliarity with the main generator field breaker and failure to observe the effect of a malfunctioning IRM recorder before a half scram condition occurred were identified during the reactor startup as potential training issues.

b. Observations and Findings

A review of the April 19 scram (Section I.01.1) is scheduled to be presented to operators during the plant status update later this year. During this presentation, a review of the critique report and licensee event report, and the pressure characteristics during a low power scram, are expected to be included. Operations management personnel indicated that a discussion of the time it took to enter EOP-2 will be included in this training. In addition, the training department will incorporate increased emphasis on low power event initiators.

During the next two months, the simulator memory capacity is scheduled to be upgraded. At this time the review board will prioritize the open deficiency reports (DRs) against the simulator to decide which modifications will be made. One of these DRs is the modeling of the HPCI system during the pressure control mode. Even if this DR is not incorporated, operators will be reminded of the actual system behavior during this mode. In addition operators have already been trained on the revision to the HPCI injection and pressure control procedure.

c. Conclusions

The corrective actions taken and planned for the misunderstanding of HPCI operation in the pressure control mode appear to be appropriate to train operators and possibly modify the simulator.

Three operator training issues became evident during this inspection period as discussed in this section and Sections I.01.2, I.01.3 and I.01.4 of this report. These issues include: 1) Operator control of reactor water level both immediately following the scram (PCIS Group I isolation) and approximately one hour later during pressure control with SRVs and HPCI (HPCI isolations on high reactor water level and PCIS Group 6 high reactor water level isolation), 2) Operator unfamiliarity with the main generator field breaker, and 3) Failure to observe the effect of a malfunctioning IRM recorder before a half scram condition occurred during the reactor startup. These operator training issues are an inspector follow item (IFI 50-293/96-03-01).

O8 Miscellaneous Operations Issues (92700)

O8.1 (Closed) LER 50-293/96-05: Automatic Scram due to Turbine Vibration During Planned Power Reduction

The inspector reviewed licensee event report (LER) 96-05, submitted to the NRC, to verify accuracy, description of cause, previous similar occurrences, and effectiveness of corrective actions. The LER was also reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022 and its supplements.

LER 96-05, dated May 20, 1996 reported the automatic scram and associated engineered safety feature actuations, which included the reactor protection system. The inspector's review of this event is described in Section I.01.2. The inspector determined that the LER was complete and is therefore closed.

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726, 62703)

Using inspection procedures 61726 and 62703, the inspector observed portions of selected maintenance and surveillance activities to verify proper calibration of test instrumentation, use of approved procedures, performance of the work by qualified personnel, conformance to limiting conditions for operation, and correct system restoration following maintenance and/or testing. The following activities were observed:

- 8.5.3.2 Salt Service Water System Pump and Valve Operability Tests
- 8.5.6.2 Special Test for ADS System Manual Opening of Relief Valves
- MR19600190 RV-203-3B Showing Indication of Pilot Leakage

b. Observations and Findings

The work was performed by knowledgeable personnel in accordance with applicable procedures and work packages. Instrumentation was properly calibrated and used where applicable. The inspector verified conformance to LCOs and post-work testing (PWT). Systems were returned to their normal configuration after testing and maintenance.

Post maintenance testing of safety relief valve RV-203-3B was conducted in accordance with Procedure 8.5.6.2. A pre-evolutionary briefing on the test procedure was conducted by the Senior Nuclear Operator and the Operations Manager, who highlighted the special testing precautions and

contingency plans. The briefing was followed by a dry run to ensure proper communications and coordination of this testing activity. Plant response to the manual cycling of relief valve RV-203-3B was as expected.

c. Conclusions

Operator performance of the manual lift test of safety relief valve RV-203-3B and the SSW system surveillance was professional, with good communications and proper coordination of testing related activities. In addition the pre-evolutionary briefing for the lift test was thorough. All activities were conducted in accordance with the applicable procedures and work orders.

M4 Maintenance Staff Knowledge and Performance

M4.1 AO-7011B Corrective Maintenance

a. Inspection Scope (62703)

A review was performed of the circumstances, evaluation and corrective actions taken to address a potentially significant maintenance error involving one of the two drywell equipment sump containment isolation valves, AO-7011B. A mechanical maintenance supervisor and two mechanics inadvertently worked on AO-7011A in lieu of AO-7011B. AO-7011B is an air-operated valve with a fail-close design. Additionally, "O"-rings staged for the work were found to be incorrect for the application during the air operator rebuild activities. The inspector attended the LCO review board meeting, attended the critique after the event, interviewed the plant and maintenance managers and reviewed the evaluation and corrective actions contained in the related problem report, PR 96.9173.

b. Observations and Findings

As part of a recent BECo initiative to improve the work planning and controls for LCO maintenance, an LCO review board meeting was held before the actual start of work. The complete work package for maintenance request (MR) 19600544 to rebuild the air operator on AO-7011B was reviewed. The review board was comprised of representatives from work control, operations, engineering and maintenance. The following key attributes were evaluated at the meeting:

- Since AO-7011B is the downstream drywell equipment sump isolation valve, the LCO review board members gave special consideration to the PWT requirements. Engineering personnel prepared a detailed, color-coded vendor drawing showing the various valve body and actuator parts. Parts subject to containment integrity requirements were clearly highlighted to assist maintenance personnel in determining the correct PWT requirements.

- The LCO review board members reviewed TS requirements. TS LCO 3.7.A.2.b, Primary Containment Isolation Valves (PCIV), specifies that in the event any PCIV becomes inoperable, at least one containment isolation valve in each isolation line having an inoperable valve shall be deactivated in the isolated condition. Also, TS Surveillance Requirement 4.6.C.1 requires monitoring of drywell leakage detection systems at least once every 8 hours. Since AO-7011B has to be open to allow pumpdown of the equipment drain sump to monitor the drywell leakage detection, the work activities on AO-7011B had to be coordinated with the shiftly equipment drain sump pumpdown. This aspect of the work required proper sequencing.

- As a contingency, if the work didn't complete before the next pumpdown was required, an operations review committee (ORC) approved procedure, TP96-011, was issued to provide the requisite administrative controls to temporarily open AO-7011B. TP 96-011 allowed removal of the spring assembly and the manual opening of AO-7011B using the manual handwheel. The inspector independently verified that the contingency plan was in accordance with TS 3.7.A.2.b which allows an inoperable containment isolation valve to be re-opened on an intermittent basis with ORC-approved administrative controls.

- The maintenance staff obtained a similar style air-operated valve and disassembled and reassembled the air-actuator several times in the shop. This mock-up allowed verification of the work plan instructions, afforded the mechanics an opportunity to practice the necessary work steps, and implemented the as-low-as-is-reasonably-achievable (ALARA) principle since the valve is located on the top of the torus in the torus room.

- The plant operations department manager completed the LCO maintenance planning checklist using Procedure 1.2.2, Administrative Ops Requirements.

The inspector determined that the LCO review board conducted a reasonably thorough review of the work package instructions to rebuild the air actuator on AO-7011B. For example, the issuance of TP 96-011 demonstrated due consideration for work contingencies. Also, a positive maintenance practice was the disassembly and reassembly of a similar mock-up valve in the shop. Additionally, the color coded vendor manual diagram clearly showed the containment integrity pressure boundary components.

On April 10, BECo initiated the rebuild of the air actuator for AO-7011B. After disassembling the valve, the mechanics found that the replacement parts were incorrect for the application. The valve was reassembled using the old parts. During the PWT (i.e., stroke and timing tests) when cycling AO-7011B, the maintenance supervisor stationed locally in the torus room realized that the work had been performed on AO-7011A in lieu of AO-7011B, as intended. The maintenance

supervisor immediately notified the control room operators. Both AO-7011A and B were successfully stroked and timed. During the work activities, which actually occurred on AO-7011A, AO-7011A remained closed at all times under spring pressure thereby maintaining primary containment integrity and complying with TS 3.7.A.2.b. Maintenance management initiated PR 96.9173 to document, evaluate and implement corrective action.

The inspector attended a critique convened to gather the facts and ensure the plant was in a safe condition. The critique concluded that primary containment was never breached. The mechanical maintenance supervisor identified the wrong valve to be worked and neither of the two mechanics verified or checked to ensure the correct valve was identified. Furthermore, the mechanics stated that the lighting was very poor at the work area on top of the torus but didn't stop the work to get temporary lighting because of the time limitations associated with the need to pumpdown the equipment drain sump every 8 hours. A temporary label was installed on AO-7011A vice a permanent identification tag. PR 96.9173 was assigned a Significance Level I which requires a formal root cause analysis. Approximately 116 mr of exposure was received during the wrong work activity. The inspector noted that even if the maintenance personnel disassembled the correct valve, the radiation exposure still would have been spent unnecessarily since the correct "O"-rings were not available.

The maintenance manager initiated Maintenance Standing Order 96-02 to provide interim self-checking guidance for maintenance workers. The standing order stated, "Prior to commencing work on a component, two individuals (unless it is a single person job) will verify the identity of the component. If it is not clear that the correct component can be identified by available means, then the work will be postponed until the proper identification can be made. Also, whenever performing maintenance on a component, each and every individual associated with the work shall identify the equipment as the correct component identified in the work document. Whenever possible, multiple means of identification should be used such as drawings, photographs, identification tags, protective tags and layout of the component in the system." Other short term corrective actions included a work stoppage, verification of compliance with TS requirements, and a critique. In addition, accountability measures were taken with the maintenance personnel involved and management held small group meetings with maintenance workers to review this event and discuss the lessons learned. The inspector determined that the short term corrective actions were reasonably thorough. The failure to follow the work package instructions by working on the incorrect valve was a violation of procedure 1.5.20, Work Control Process, Step 7.6[5](d) which states the maintenance supervisor and workers shall perform work in accordance with the work request instructions and procedures. This licensee-identified and corrected violation is being treated as Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy.

The inspector obtained a copy and reviewed the draft human performance enhancement system (HPES) evaluation initiated by PR 96.9173. The draft HPES evaluation had been completed by maintenance personnel and was scheduled to be reviewed in the near term by the problem assessment committee (PAC). Hence, the draft root cause had not yet been reviewed and approved. The inspector observed that the draft HPES evaluation was quite brief and simply repeated the root cause and contributing causes identified at the critique held to gather the facts and verify the plant was in a safe condition. The draft HPES determined, in the extent of the problem section, that this event was a unique situation. Also, the draft HPES evaluation did not evaluate the following issues which were evident at the critique: schedule pressure, lack of temporary lighting, lack of a maintenance supervisor pre-work area inspection and the reason for incorrect parts that were staged for this LCO maintenance. The inspector determined that the draft HPES report did not address these human performance issues that occurred during this event and were discussed during the critique. The inspector discussed the draft HPES report with the maintenance manager. The maintenance manager agreed with the inspector's concern and retracted the draft HPES report, extended the PR corrective action due date and initiated another HPES review. The maintenance manager informed the inspector of a management decision already made to create a maintenance department, full time, root cause and corrective action position. Also, accountability measures had already been taken with the various individuals involved. Shortly after the end of this inspection period, the plant manager initiated an issue team using Procedure 1.3.109, Issue Management, to thoroughly review all human aspects of this event.

Pending inspector review of the issue team report, these human performance issues associated with the longer term corrective action aspects of this event will remain as an unresolved item **(UNR 50-293/96-03-02)**.

c. Conclusions

A maintenance supervisor and mechanics disassembled the incorrect equipment sump drain line containment isolation valve, working on AO-7011A in lieu of AO-7011B, during limiting conditions for operation (LCO) maintenance. No adverse safety consequence occurred due to the fail close design of the valve which remained closed during the maintenance. This near miss for containment integrity was self-identified. Plant management initiated timely and meaningful short term corrective actions such as convening a critique, initiating a maintenance night order stressing component identification and self checking, and holding feedback sessions with maintenance workers. The failure to follow the work package instructions was treated as a non-cited violation considering the proper short term corrective actions.

However, limited progress was made by the end of this inspection period in implementing longer term corrective actions. The draft human performance enhancement system (HPES) report completed by maintenance personnel did not address important human performance issues that were

evident at the critique. For example, the pre-work area maintenance supervisor inspection, adequacy of lighting, schedule pressure and review of incorrect replacement parts were not evaluated. These shortcomings in the draft HPES report existed 60 days after the event. Subsequently, plant management initiated an issue team to re-perform the detailed root cause evaluation to fully evaluate all human performance aspects of this event. The longer term corrective actions, including the root cause evaluation, will remain as an unresolved item **(URI 50-293/96-03-02)** pending NRC review of the issue team report.

M6 Maintenance Organization and Administration

M6.1 Outage Work Control

a. Inspection Scope (62703)

During deep back shift inspection, the inspector monitored the effectiveness of the work control aspects of the April maintenance outage. Two significant work activities inside the drywell involved the replacement of the "A" recirculation pump mechanical seal cartridge and the pilot assembly for RV-203B. The planned outage duration was 4.75 days with 82 corrective action maintenance requests, 11 surveillance tests and two modifications. BECo employed a new concept of work control planning teams to develop the detailed outage schedule windows.

b. Observations and Findings

The inspector observed the following salient outage work activities:

- A centralized work control area was staffed 24 hours each day during the outage, providing effective work control management focus. Many emergent items and possible conflicts for planned work were immediately resolved, allowing effective work completion. Plant workers supplied work control managers pertinent facts to allow timely and well informed decision making. One minor opportunity for improvement was identified related to the quality and quantity of the log book entries maintained in the work control area. The inspector noted that important work control planning and performance information may not have been documented to allow subsequent review.

- The maintenance supervisors provided extensive oversight of the "A" recirculation pump mechanical seal cartridge replacement activity. A high resolution camera allowed excellent remote work monitoring capability.

- Electricians stopped work to make an important procedure change (i.e., REV. 2) to Procedure No. 3.M.3-7.1, Inspection and Maintenance of Recirc MG Set Brushes and/or Brush Rigging. The change was needed since the new fuse holders did not need to be removed for cleaning. Also, steps were added for disconnecting field wires which were previously disconnected without a step for

meggering the brush holder. The procedure change reflected the electricians' understanding of proper procedure usage.

- The inspector witnessed the nuclear watch engineer (NWE) go to the drywell access point to inform plant workers before changing the mode switch position for front panel checks which would result in a scram. Based on this input, radiation protection (RP) and maintenance personnel were able to inform workers inside the drywell. After the scram, the inspector witnessed a RP technician re-survey the hydraulic control unit area. These positive actions displayed excellent interdepartment communications and teamwork.

- During a drywell inspection, the inspector witnessed work progressing as planned for the replacement of the pilot assembly on RV-203B.

- Over 40 additional work tasks emerged during the outage that were scheduled and completed. Nonetheless, the outage was completed in 5.5 days, only slightly exceeding the planned duration of 4.75 days. A post trip review team carefully reviewed (during the outage) the related issues to the unexpected automatic scram.

- Shortly after the outage, the work control and outage managers convened a lessons learned meeting to identify what worked as planned and also to develop any further opportunities to improve. The outage report indicated that one noted improvement was greatly improved radiological protection coverage as compared to past outages.

- The outage report also identified that improvements were needed, including troubleshooting activities, in the maintenance of nuclear instrumentation.

c. Conclusions

The outage maintenance activities were well planned and controlled. Plant management placed special emphasis on doing the job right the first time and effective use of procedures. For example, electricians stopped work to obtain an important procedure change involving the recirculation pump motor generator set electrical brushes. Strong supervisory oversight of the recirculation pump seal cartridge placement was evident. Also, an NWE informed plant workers in advance of changing the mode switch position so that drywell workers could be informed of the impending noise and change in area dose rates.

III. ENGINEERING

E8 Miscellaneous Engineering Issues (92903)

E8.1 (Closed) Inspector Follow Item (IFI 50-293/96-01-01): Degraded Individual Rod Scram Times Due to Viton Diaphragm Problems

a. Inspection Scope

Degradation of control rod scram times has been observed at BWRs since last year. The slower scram times are due to the degradation of the scram solenoid pilot valve (SSPV) Viton exhaust diaphragms. Section 4.1 of NRC Inspection Report 50-293/96-01 discussed this issue as it pertained to PNPS. During this inspection period, the licensee gathered additional scram time information which was used to determine whether replacement of the SSPV exhaust diaphragms during the planned April maintenance outage was necessary. The inspector reviewed BECo's temporary procedure, use of owners' group guidelines, and scram time data to determine the adequacy of the licensee's plan and implementation of the plan. The inspector also discussed this generic issue with engineering personnel to determine their awareness of industry information and progress in this area.

b. Observations and Findings

During the reactor shutdown for the April 19 outage, BECo planned to scram the reactor at approximately 10 percent power to obtain scram time data for over 50% of the 145 control rods. Prior to this outage, the inspector discussed the licensee's criteria for replacing the scram solenoid pilot valve exhaust diaphragms with engineering personnel. BECo developed temporary procedure TP96-013, Evaluation of Control Rod Scram Notch 44 Insertion Time Performance, which incorporated BECo's implementation of the Boiling Water Reactor Owners' Group (BWROG) Regulatory Response Group's (RRG) recommendations. This procedure clearly identified the acceptance criteria for the scram times and described corrective actions including replacement of all SSPV diaphragms, increasing the frequency of scram time testing, and replacement of SSPV diaphragms for selected rods.

Since PNPS TS incorporate limits for 10 percent scram times (Notch 48 to Notch 44) instead of the typical 5 percent scram times (Notch 48 to Notch 46) seen at other BWRs, the RRG recommendations needed to be amended to apply them to PNPS. The licensee discussed these specific limits with the RRG, determined limits applicable to Pilgrim, and adopted most of the original RRG recommendations for use at Pilgrim.

Two differences existed between the RRG recommendations and those adopted by Pilgrim in the areas of the frequency of reference sample testing and the criteria for determining slow rods. While the RRG suggested testing a reference sample (8) of control rods every 60 days and a representative sample (17) of rods every 120 days, Pilgrim plans to test both the reference and representative samples (25 rods)

approximately every 90 days. In this way, although the reference sample is tested less frequently, the representative sample is tested more frequently than the 120 days required by TS and results in a larger sampling of control rod times overall. The second difference relates to the determination of slow rods. The RRG recommended using a criteria of more than 0.49 seconds for declaring a rod inoperable/slow. PNPS has adopted slow rod criteria that require both a scram time greater than 0.61 seconds and an overall degradation from the beginning-of-cycle (BOC) time of 0.06 seconds. The inspector verified that the adopted 0.61 criterion is comparable to that set for the 5 percent scram times for other BWRs. The inspector questioned the reasoning for the additional requirement of 0.06 second degradation with the issue manager who is also the system engineer. The 0.06 seconds corresponds to the margin PNPS had at the BOC to the TS limit. The licensee reasoned that since the purpose of the slow rod criteria is to identify rods that have experience degradation, it is also appropriate to show there has been an increase in insertion time since BOC. There was one rod, 34-27, which had a 10 percent insertion time of 0.62 seconds at BOC at Pilgrim, therefore only using the 0.61 criteria would not have identified any degradation in the scram time for this rod.

The inspector reviewed the scram time data obtained during the April 19 scram. Scram times were obtained for 94 of the 145 control rods. The inspector independently reviewed the 10 percent scram time calculations and verified no rods fell within the slow rod criteria or required diaphragm replacement per the TP. Only a 0.001 second degradation in the individual 10 percent scram times was noted since the scram testing performed in January. However, when this data was combined with the most recent data for the remaining rods, a core average 10 percent scram time of 0.50 was obtained showing no degradation since January from the TS core average limit of 0.55 seconds.

c. Conclusions

The licensee appropriately monitored the degradation of the scram solenoid pilot valve exhaust diaphragms through collection and analysis of scram time data this period. The temporary procedure developed to gather scram time data and determine corrective actions was thorough and appropriately incorporated engineering's recommendations. The licensee communicated effectively with the RRG to determine applicable plant-specific slow rod acceptance criteria. Although the licensee's adopted actions in response to this issue differed from the timing frequency and slow rod criteria recommended by the RRG, the justification and overall method for determining degradation were reasonable. The inspector concluded that the licensee developed an appropriate temporary procedure, acceptance criteria, and corrective action plan. In addition the licensee was in frequent contact with the industry to remain current on development of a solution to this generic issue. This item is closed (IFI 50-293/96-01-01).

IV. PLANT SUPPORT

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Outage Radiological Controls

a. Inspection Scope (71750)

A review was performed of the planned radiation exposure and actual exposure results during a 5.5 day maintenance outage which began on April 18, 1996. The inspector reviewed the exposure planning and actual results, held discussions with the acting radiological department manager, and monitored the work sites in the drywell during a drywell tour and remotely viewing the monitor from the high resolution camera.

b. Observations and Findings

Two significant outage work activities inside the drywell were the replacement of the "A" recirculation pump mechanical seal cartridge and replacement the pilot assembly on safety relief valve RV-203B. These two major outage work activities were planned by using multi-disciplined teams. The exposure estimates were based on a combination of previous experience and planning reviews. The following table contains relevant exposure data.

Work Description	Planned Exposure and Hours	Actual Exposure and Hours
Replace pilot assembly on RV-203B	1.4 REM 65 hours	0.993 REM 22 hours
Replace "A" recirc. pump mechanical seal	2.375 REM 329 hours	2.799 REM 124 hours
Total planned (scheduled) work	13.46 REM	13.03 REM
Emergent Work	N/A	3.6 REM

The recirculation pump work was completed slightly over the budgeted exposure goal of 2.375 REM. Several dose reduction strategies were developed and built into the work plan. For example, temporary shielding was installed at the discharge side of the recirculation pump bowl designed to save 0.510 REM. Also, a high resolution camera was used to allow remote monitoring of the work activity. Moreover, as documented in the previous resident inspector report, 50-293/96-02, extensive mock-up training was conducted to practice the seal cartridge replacement. Lastly, contaminated parts were sprayed with water mists to minimize the potential for the spread of contamination.

After the work was completed, BECo reviewed the lessons learned to further improve future seal replacement activities. A large beam difficult to manipulate interfered with access to the seal replacement work area. Also, the seal lifting beam and cartridge inside of the recirculation pump shroud required extensive handling due to local interferences. For both interference issues, radiation protection requested an engineering review for possible design changes to minimize the interference effect and thus further reduce the worker exposure. The work to replace the pilot assembly on RV-203B was completed under the budgeted exposure goal of 1.4 REM.

The inspector observed that the estimated work hours for the RV-203B and the "A" recirculation pump work activities exceeded the actual hours by a general factor of 3. The planned maintenance work hours exceeding the actual work hours was also noted during a recent reactor water clean-up system outage as documented in Section 5.1 of NRC Inspection Report 50-293/95-26. The estimated work hours are supplied by maintenance and planning personnel. Although the exposure estimates were close to the actual exposure received during the work, the large deviation between the planned and actual hours indicate that the more detailed work hour estimates used in developing the exposure estimates (i.e., time in radiation field) was not input back into the ALARA planning. Since time spent in a radiation field is directly proportional to the exposure received, the inspector determined that a potential weakness may exist involving the work hour estimates, used to develop exposure goals, which maintenance provided to ALARA.

c. Conclusions

The exposure results for two significant outage work activities, replacement of the mechanical seal cartridge on the "A" recirculation pump and replacement of the pilot assembly for RV-203B, were completed with exposure results close to the ALARA exposure goals. Initiatives such as using remote high resolution cameras to monitor recirculation pump work, detailed pre-planning, and the use of temporary shielding contributed to this positive performance. The actual total outage dose of 13.03 Rem for planned work activities was less than the planned outage dose of 13.46 Rem. The work hour estimates supplied by maintenance and planning and used by ALARA for the recirculation pump and RV-203B exposure estimates were generally three times greater than the actual time required to complete the jobs. The planned maintenance work hours exceeding the actual work hours was also noted during a recent reactor water clean-up system outage. The large deviation between the planned and actual hours indicate that the more detailed work hour estimates used in developing the exposure estimates (i.e., time in radiation field) was not input back into the ALARA planning. Since time spent in a radiation field is directly proportional to the exposure received, the inspector determined that a potential weakness may exist involving the work hour estimates, used to develop exposure goals, which maintenance provided to ALARA. This potential weakness in maintenance work hour estimates is an inspector follow item (IFI 50-293/96-03-03).

V. MANAGEMENT MEETINGS

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on June 21, 1996. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

X4 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for additional verification that licensees were complying with Updated Final Safety Analysis Report (UFSAR) commitments. For an indeterminate time period, all reactor inspections will provide additional attention to UFSAR commitments and their incorporation into plant practices and procedures. While performing inspections discussed in this report, inspectors reviewed the applicable portions of the UFSAR. No inconsistencies were noted.

INSPECTION PROCEDURES USED

IP 61726	Surveillance Observations
IP 62703	Maintenance Observations
IP 71707	Plant Observations
IP 71750	Plant Support Observations
IP 92700	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92903	Followup - Engineering
IP 93702	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND UPDATED

Opened

IFI 50-293/96-01-01	Operator Training Issues Related to the April 19, 1996, Scram and Subsequent Startup
UNR 50-293/96-01-02	Human Performance Issues Related to Working on the Wrong Containment Isolation Valve
IFI 50-293/96-01-03	Weakness in Maintenance Work Hour Estimates

Closed

IFI 50-293/96-01-01	Degraded Individual Rod Scram Times Due to Viton Diaphragm Problems
LER 50-293/96-05	Automatic Scram due to Turbine Vibration During Planned Power Reduction

Updated

None