ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.	50-293
Licensee No.	DPR-35
Report No.	97-02
Licensee:	Boston Edison Company 800 Boylston Street Boston, Massachusetts 02199
Facility:	Pilgrim Nuclear Power Station
Location:	Plymouth, Massachusetts
Dates:	March 3 - April 28, 1997
Inspectors:	Richard A. Laura, Senior Resident Inspector Beth E. Korona, Resident Inspector Suresh Chaudhary, DRS Engineering Inspector Ed Knutson, Vermont Yankee Resident Inspector Patrick Madden, NRR Senior Fire Protection Engineer James Noggle, DRS Radiation Specialist
Approved by:	Richard Conte, Projects Branch 8 Division of Reactor Projects

EXECUTIVE SUMMARY

Pilgrim Nuclear Power Station
NRC Inspection Report 50-293/97-02

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers resident inspection for the period of March 3 through April 28, 1997. In addition, it includes the results of announced inspections by regional radiation and inservice inspection specialists.

Operations:

Operator performed RFO11 activities well including the oversight of the vendor fuel handlers during core reload activities. The management decision to confirm the integrity of the used fuel bundles during in-pool gas sipping activities directly led to the identification of a second leaking fuel pin. Two of the three longstanding operator work arounds that came into effect during the shutdown into RFO11 were corrected. Operations training personnel performed a detailed and insightful review of operator performance during the previous reactor scram due to malfunctioning feedwater system regulating valves. (Section O1.1)

Two minor equipment deficiencies were identified during control room panel walkdowns which were discussed with members of the operating crew. Also, an operations tagging problem was evident when a worker was observed to be conducting maintenance on a pressurized valve when an isolation valve was 1 to 2 turns open from the full closed position. (Section O1.1)

Operators responded well to the main transformer failure on March 7. Good command-and-control resulted in restoration of augmented fuel pool cooling with a very small rise in spent fuel pool temperature and careful transferral of plant loads to the startup transformer. (Section O1.2)

Operators responded well to the unusual event due to the complete loss of offsite power on April 1. Effective command-and-control was demonstrated by appropriate declaration of an Unusual Event, entrance into EOP-4, and presence of the emergency director in the control room. The decision to remain in the Unusual Event (UE) after the 23 KV line was restored, pending restoration of the 345 KV lines and stability in the lines, showed a prepared approach. Operators closely followed appropriate procedures to restore temporary power to non-safety related equipment to exit EOP-4 and restore fuel pool cooling. (Section O1.3)

Although operators were aware of the loss of auxiliary power to the SBO diesel after the main transformer failure, actions were not timely enough to prevent loss of the SBO diesel availability. This resulted from an inadequate procedure and ineffective interface with the system engineer. (Section O2.1)

The readiness for restart meeting effectively reviewed numerous issues prior to restart. Operators performed start-up and power ascension activities in a professional and controlled manner with due regard for nuclear safety. A few minor deficiencies were identified by the NRC during the final drywell close-out inspection performed with reactor pressure at 1000 psig. Two equipment/system degraded conditions **(URI 97-02-01)** involving the degraded operation of control rods and feedwater system regulating valves impacted operational activities during start-up and power ascension from RFO11. Strong operator command-and-control was evident during the turbine overspeed testing. Four attempts were needed to re-synchronize the generator back onto the electrical grid due to an operator training weakness. (Section O4.1)

Maintenance:

Pre-evolutionary briefs for observed tests were thorough and stressed procedure adherence, proper chain-of-command and self-checking. Operations management was often present to provide oversight and stress the importance of several of the tests performed. The questioning attitude of an operator during an ECCS load sequencing with loss of offsite power test prompted better preparation for the test and further review of the procedure for improvement. Degraded reactor pressure vessel flange temperature elements delayed the reactor pressure vessel leakage test and required a temporary modification to be installed prior to startup. Portions of the test were reran when a recorder was not turned on. (Section M1.1)

The BECo response to a fire in the "B" RFP motor was timely and effective. Short term corrective actions were thorough and addressed the apparent cause (degraded motor heaters) for all three RFPs. Existing preventive maintenance on safety related pump motors provides reasonable assurance that these motors are not susceptible to similar failure. (Section M2.1)

Efforts to transport, install, modify and ultimately energize the new main transformer, following the failure of the original transformer on March 7, reflected good overall control by the maintenance and engineering staffs. Careful transportation, appropriate electrical calculation revisions, and required modifications to associated equipment were verified which led to successful energization on April 21. (Section M2.2)

A brief loss of shutdown cooling (LER 97-006) resulted from inadequate procedure 2.2.14. BECo corrective actions were appropriate to the circumstances. (Section M3.1)

The new vessel stud tensioners worked smoothly with no problems during vessel reassembly. This resulted in less manual effort required by the refuel crew workers and also less radiation exposure due to the efficiency of the new tensioners. Damage to all four main steam line plugs occurred with a resultant loose part falling into the vessel due to an inadequate vessel reassembly procedure. The procedural inadequacy resulted from an over-reliance on verbal vendor information based on experiences at other BWRs rather than a detailed technical review of design drawings to confirm the proper clearances between the steam separator and the plugs. However, a proper safety perspective was evident by removing the separator and retrieving the loose part. An RFO11 lessons learned review was planned to develop what worked well and areas for improvement. (Section M6.1)

Engineering:

The unexpected automatic isolation of the 480/120 V regulating transformers resulted from brief and severe undervoltage transients during a winter storm. The reason the isolations were unexpected was that the design documentation did not specify the isolation function of the transformers on under/overvoltage. This failure to maintain adequate design control is the first example of a violation of 10 CFR Part 50 Appendix B, Criterion III, Design Control **(VIO 97-02-02)**. (Section E2.1)

Inadequate electrical configuration involving MO-1301-53 resulted in an unnecessary challenge to the RCIC system turbine and increased safety system unavailability time. The overall RCIC unavailability time still remained very low. This failure to maintain adequate design control is the second example of a violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control **(VIO 97-02-02)**. (Section E2.2)

Five REM of additional radiation exposure was used to rework several of the ECCS suction strainer slip joints that were misaligned. A preliminary review determined the likely cause involved a weakness in the templating and fabrication process. Although engineering personnel identified the misalignment by watching a videotape, the engineering design documents did not highlight the critical nature of the slip joint clearances. As a result, the project implementation staff assumed the clearances were for construction fit-up; and, also, vendor QA personnel did not have a specific hold point inspection requirement. The design engineer and BECo QA personnel did not review the vendor inspection plan. (Section E3.1)

Ultrasonic examinations performed during RFO11 as part of the core shroud inspection plan revealed no reportable indications of V-17 and V-18 vertical welds. Engineering and quality assurance personnel promptly evaluated industry experience on core shroud issues that were documented in NRC Information Notice 97-17. (Section E7.1)

Based on the above observation, review of documentation, and discussion with personnel responsible for ISI program implementation, the inspector concluded that the licensee's ISI program plan, with relief requests, is approved by the NRC, and is satisfactorily maintained in an updated condition. The NDE personnel are properly qualified/certified, and inspections/examinations are adequately performed and documented. Jet pump nonconforming issues did not affect immediate operability but the final corrective actions were not planned and remain as an inspector follow item **IFI 97-02-03**. (Section E8.1)

Plant Support:

RP control points were well staffed and functioned very well in providing the radiological protection requirements of the workers. Some drywell posting and industrial safety concerns were noted and corrected by the licensee. (Section R1.1)

Effective air sampling was provided in the work areas, and proper procedures were followed in determining internal exposures. The control of contamination and limiting internal exposures through the use of respiratory protection during RFO11 was very effective. (Section R1.2)

Chemical decontamination of the recirculation piping system effectively mitigated the four-fold increase in drywell dose rates experienced this outage, however, due to an unforeseen interference and vendor equipment limitation, the decontamination effects were limited, with drywell dose rates remaining generally higher than previous refueling outage values. (Section R1.3)

Facility modifications involving RCA access and RCA tool control were recently streamlined and greatly enlarged. These modifications effectively increased the worker's interface with RP personnel and provided an increased supply of RCA tools to meet the worker's needs. These were excellent improvements to the RCA access control program. (Section R2)

Effective RP personnel resource allocation was observed during RFO11. (Section R6)

The recording of radiological occurrences has experienced an approximate six-fold increase due to a recently implemented problem reporting threshold. It was too early to assess the results of the newly revised problem report process on correcting and lowering the number of radiological occurrences. (Section R7)

The emergency plan was implemented as required during the Unusual Event on April 1, 1997. After the event, an accurate event report was written that reviewed the organization's response and identified any problems encountered. Appropriate corrective actions were identified and tracked to resolve the minor difficulties encountered. (Section P1.1)

The existing configuration of radiation monitors on the refuel floor does not satisfy the requirements of 10 CFR 70.24, "Criticality accident requirements." In addition, BECo has not conducted evacuation drills as required by this part. BECo committed to come into compliance with the regulation or receive an exemption prior to receiving, handling, or storing any new fuel. The NRC is currently reviewing the problem in light of its Enforcement Policy. Accordingly, this area is unresolved **(URI 97-02-04)** pending further NRC staff review. (Section P2.1)

Based on the on-site review of the existing plant conditions and fire protection features, the inspector concluded that the fire protection enhancements should provide reasonable assurance that if this event or a similar one were to occur, the transformer oil fire hazard would be controlled and the potential fire effects on safe shutdown and safety related electrical components would be minimized. The new fire protection enhancements will provide an additional level of fire safety diversity. (Section F2.1)

The fire hazard analysis did not reflect potential fire loading in the turbine building and radwaste area commensurate with the oil spill after the main transformer failure because this was not an anticipated failure mode. The enhancements to install berms in the turbine building and drain lines on the isophase duct lines will limit the fire loading effect on these areas should a similar failure occur in the future. The fire hazard analysis report was updated to reflect these changes before plant startup following RFO11. (Section F3.1)

TABLE OF CONTENTS

REPORT DETAILS

Summary of Plant Status

Pilgrim Nuclear Power Station (PNPS) began the period shut down and in refueling outage 11 (RFO11), which commenced on February 15, 1997. During the outage, several maintenance activities were completed including refueling of the reactor core, replacement of core plate plugs, installation of new, larger emergency core cooling system suction strainers, and chemical decontamination of portions of recirculation system piping.

At 14:49 on March 7, 1997, while in a backfeed lineup, the main transformer failed. (Sections I.O1.2 and I.O2.1) At the time, the other source of 345 KV power, the startup transformer, was out of service for maintenance. The loss of 345 KV power constituted a partial loss of offsite power, causing the automatic start of the "B" emergency diesel generator and reactor building and partial primary containment isolation system Group II isolations. An emergency notification (EN 31912) was made to the NRC pursuant to 10 CFR 50.72(b)(2)(ii). The resident inspector responded to the control room and observed recovery efforts and transfer of the emergency buses to the startup transformer. The restoration was completed during early morning hours on March 8. Following this event, BECo transported a spare transformer from the Millstone Nuclear Generating Station, modified and installed it for use at PNPS (Section II.M1.1).

On March 21, at 13:36, shutdown cooling was lost to the reactor vessel for 24 minutes. The loss resulted from troubleshooting activities on a ground in the 125 VDC system (Section II.M3.1). Operators reported the loss to the NRC as required by 10 CFR 50.72(b)(2)(ii). (EN 31992)

At 02:57, on April 1, operators declared an UE due to the total loss of offsite power (LOOP). (EN 32059) The LOOP occurred during a strong northeastern storm with high winds and heavy snow accumulations in eastern Massachusetts (Section I.O1.3). A total loss of offsite power is defined as the loss of both 345 KV and the 23 KV offsite power lines. As a result of the loss of offsite power, a primary containment isolation system (PCIS) partial Group III isolation signal resulted in the isolation of shutdown cooling. Shutdown cooling was lost for approximately 13 minutes. (EN 32060) The resident inspector responded to the site and observed recovery actions. Operators terminated the UE at 23:47 that night, after all three offsite power lines were restored. The UE and PCIS isolation were reported to the NRC as required by 10 CFR 50.72(a)(1)(i) and 50.72(b)(2)(ii), respectively. Both NRC headquarters and Region I emergency response centers entered the monitoring mode during the UE. NRC emergency response personnel were periodically briefed on plant status and weather conditions in the Plymouth area by the resident inspector and BECo personnel, as required.

Operators brought the reactor critical at 19:53 on April 14. Operators placed the unit on-line through the newly-installed main transformer at 0445 on April 21. Operators continued to increase power and performed required testing at the appropriate power levels. On April 28, at 17:00, operators took the reactor to approximately 100 percent power.

On April 17, at 13:15, operators declared the reactor core isolation cooling system (RCIC) inoperable after it failed to perform as expected during a quarterly surveillance test (Section III.E2.2). Operators entered the required 14 day limiting condition for operation. Following troubleshooting activities, the RCIC system was declared operable later that day. The reactor remained at approximately 18 percent power throughout the time RCIC was inoperable.

I. OPERATIONS

O1 Conduct of Operations[1]

O1.1 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. Anomalies noted during tours were discussed with the 905 reactor operator or the nuclear watch engineer (NWE). The loss of position indication for one safety relief valve (SRV) and a malfunctioning, reading 400 gallons/minute with no operating RHR pump, "A" loop RHR total flow digital indicator were identified by the inspector and discussed with members of the crew. The loss of SRV position indication resulted from a burned-out light bulb and a problem report was initiated to resolve the "A" RHR total flow indicator deficiency. These two items were isolated in nature but represented opportunities for more effective operator and management control room panel walkdowns. The inspector also witnessed a tagging problem when a condenser bay worker disassembled the #1 valve to LV-3150 (nonsafety related) which was unknowingly pressurized with air. Discussions with the worker revealed the isolation valve was tagged shut but was actually 1 to 2 turns open from the full close position. Problem report 97.1031 was written to document and evaluate this problem. Operations department management later determined that the apparent/direct cause was unknown. Other tagouts were checked with no other similar problems identified.

In-pool gas sipping during refueling operations identified a second leaking fuel bundle which was subsequently reconstituted. The inspector notes that the decision to verify the integrity of all reloaded fuel bundles reflected a proper emphasis on nuclear safety. Reload of the reactor core was completed in a professional manner with effective oversight of the contracted fuel handlers by BECo senior reactor operators. Major loop swaps of safety related systems were well controlled. Since the individual operating procedure line-ups contained both trains, operators had to split out the loops and initiate a problem report as specified by the conduct of operations procedure. This delayed operators from completing all reviews prior to restoring systems back to an operable status. All valve/component line-ups were appropriately completed prior to plant restart.

---

[1]Topical headings such as O1, M8, etc., are used in accordance with the NRC standardized reactor inspection report outline. Individual reports are not expected to address all outline topics.

The operator training department completed a detailed review of operator performance during the reactor scram that occurred during the shutdown to begin RFO11. Progress was made prior to restart from RFO11 to eliminate 2 of the 3 significant work arounds that came into effect during the February 15, 1997 post reactor scram period. MO-220-3 was replaced with a new and more conventional style valve and CV-1239 (RWCU letdown control valve) was repaired by replacing the valve trim and implementing a design change to the low and high pressure interlock setpoints to eliminate the need to use the mechanical blocking device. Corrective actions were planned to resolve the temporary loss of the control rod full-in light indication in the near term.

The inspector attended the offsite review committee (NSRAC) meeting held on April 9, 1997. At the meeting, various BECo managers made presentations to the NSRAC members. The NSRAC members effectively recognized and reminded BECo managers of the significance of the loss of the use of the station blackout (SBO) diesel during the transformer failure event on March 7, 1997. The radiation protection department manager provided an excellent briefing on the radiological aspects of RFO11 and overall performance in this department.

O1.2 Main Transformer Failure While in Backfeed Alignment

a. Inspection Scope (71707)

On March 7 at 14:49, an internal fault caused the isolation of the main transformer. The inspector observed operator and plant personnel actions in the control room and other site locations. The inspector reviewed the report issued by the lessons learned team established after the transformer failure and periodically discussed aspects of the team's review with the team leader.

b. Observations and Findings

On March 7, PNPS was in a refueling outage and the main transformer was supplying 345 KV offsite power to the plant, including the safety related 4160 V buses, through a backscuttle arrangement through the auxiliary transformer. The other transformer which may be used to supply 345 KV power, the startup transformer, was tagged out of service for planned maintenance as was the "A" emergency diesel generator (EDG). The shutdown transformer was powered from the 23 KV offsite power line and also the station blackout (SBO) diesel generator (DG) remained available as an alternate source of power. All nuclear fuel had been offloaded and was stored in the spent fuel pool. The spent fuel pool was cooled by the "A" loop of augmented fuel pool cooling (AFPC) which ties the residual heat removal system into the fuel pool cooling system to handle the decay heat generated by the offloaded fuel.

At 14:49 an internal fault caused the isolation of the main transformer. Because the startup transformer was unavailable to supply power to safety related buses A5 and A6, the "B" EDG automatically started and loaded onto bus A6, as designed. Because the "A" EDG was out of service, the shutdown transformer automatically closed onto bus A5 as expected. A reactor building isolation system (RBIS) and partial primary containment isolation system Group 2 isolation also occurred, as expected, when power was lost to

PCIS. As a result of the dead bus when the main transformer was lost, AFPC isolated. Operators followed procedure 2.2.85.2, Augmented Fuel Pool Cooling (Without Shutdown Cooling) Mode 2, and returned the system to service approximately 50 minutes later, with an insignificant increase in fuel pool temperature of 2 degrees Fahrenheit. The inspector observed effective nuclear operations supervisor (NOS) command and control which resulted in the return of AFPC to service per procedure and entrance into procedure 2.4.16, Distribution Alignment Electrical System Malfunctions. Operators followed the steps of Attachment 13, Loss of Power Flow Chart, to maintain/supply power to safety related equipment. BECo personnel quickly identified the need to restore the startup transformer to operation, reviewed the status of the maintenance which had been performed and worked to clear the associated tagouts in a timely manner.

The internal fault failed a bushing which allowed approximately 1000 gallons of transformer oil to gravity drain into the main transformer's rock trap, located outside. Approximately 4300 gallons of oil also gravity drained through the isophase bus ducting into the turbine building. The inspector observed portions of the cleanup effort and noted effective containment actions by personnel immediately after the failure which prevented oil from flowing from the turbine trucklock area outside. Within an hour of the transformer failure, the fire brigade was dispatched to the turbine building and remained mobilized in standby until 345 KV power was restored via the startup transformer. Also, an announcement was made to ban all smoking on site. Sections IV.F2.1 and F3.1 discuss the transformer oil spill and fire hazard analysis.

Approximately six hours into the event, operators attempted to start the SBO DG which subsequently tripped due to low oil pressure. This topic is discussed in Section I.O2.1. This diesel was not required to supply power during this event since the 23 KV line was not lost and no adverse weather conditions existed.

Maintenance and operations personnel returned the startup transformer to service at 01:13 on March 8. The inspector observed operators carefully transfer site loads to the transformer in accordance with procedure. The inspector noted that operators restored the non-safety related loads first in order to verify that there were no problems with the transformer which could have caused cycling of the emergency buses had they been placed on the transformer first and it tripped. Buses A5 and A6 were transferred to the startup transformer at 01:56 and 02:53, respectively. Operators secured the RHR pump in AFPC prior to the transfer of A6 and restarted it after power was restored. This action prevented AFPC from automatically isolating on the dead bus as it had when the main transformer was lost. AFPC was isolated for approximately 25 minutes with no significant spent fuel pool temperature increase. At 03:21 operators secured the "B" EDG, which ran satisfactorily throughout the event.

A lessons learned team was established after the event. The team discussed the event with applicable parties; reviewed and identified improvements to procedures, analyses, interfaces, etc; and entered corrective actions into the plant database to be tracked. The team identified several areas for improvement including a review of design modifications and compensatory measures for the SBO diesel, enhanced transformer monitoring, review/revision of the fire hazards analysis, and installation of emergency lockers at various locations. The inspector verified that each action item was assigned a due date, owner, and a number which will be tracked via existing programs including the problem report system.

c. Conclusions

Operators responded well to the main transformer failure on March 7. Good command and control resulted in restoration of augmented fuel pool cooling with a very small rise in spent fuel pool temperature and careful transferral of plant loads to the startup transformer.

O1.3 Unusual Event Due to Complete Loss of Offsite Power

a. Inspection Scope (93702)

At 03:49 on April 1, the operators declared an UE at PNPS due to the inability to provide offsite electrical power to the safety related electrical buses. The inspector responded to the site to observe operator and plant personnel actions during the unusual event. The inspector also attended the subsequent event critique and reviewed the critique report and corrective actions initiated. Detail on the emergency response is documented in Section IV.P1.1.

b. Observations and Findings

The UE occurred during a severe Northeastern storm which resulted in the loss of the two preferred 345 KV offsite power lines (i.e. the number 342 Canal and 355 Bridgewater), that had been supplying the station's switchyard and startup transformer, as well as the 23 KV offsite line that had been supplying the shutdown transformer. 345 KV is the preferred source of offsite power, while the 23 KV line is the secondary source of offsite power. Prior to the event, the plant was in RFO 11 with the reactor fuel loaded into the core and the vessel reassembled. Power to plant loads was supplied by the 345 KV switchyard through the startup transformer. The main transformer, through which 345 KV power may also be supplied, remained out of service since the March 7 failure of the old transformer. The new transformer was onsite but installation was not complete. Core cooling was supplied by the residual heat removal system in the shutdown cooling mode. The spent fuel pool cooling system was in service maintaining fuel pool temperature approximately 82 degrees Fahrenheit.

The 342 line began to receive intermittent isolations at approximately 22:21 on March 31. At 02:25 operators isolated the 355 line from the switchyard. Operators then started both EDGs and placed them on their associated emergency buses in anticipation of the potential loss of the 355 line. At 02:57 the 342 line was lost. Upon the loss of both 345 KV sources, and the resultant loss of the startup transformer, the non-safety related buses de-energized which caused the de-energization of the reactor protection system motor-generator sets and the resultant isolation of shutdown cooling. Operators quickly restored shutdown cooling within 13 minutes with no discernable increase in temperature. Operators started the station blackout diesel generator at 03:25 and ran it unloaded in accordance with procedure 2.2.146 because power was lost to its auxiliaries when the non-safety related buses de-energized. The last offsite power line, 23 KV, was lost at 03:39. At 03:49 operators appropriately declared the unusual event in accordance with emergency action level (EAL) 6.3.2.1, Electrical System Failures, of the PNPS Emergency Plan due to the inability to immediately provide a source of offsite AC power to buses A5 and A6.

Although the 23 KV line was restored at approximately 06:43, plant management conservatively decided not to declassify the event until stability could be assured and at least one 345 KV line was restored. The 355 line was restored and closed into the PNPS switchyard at 21:44. Both 345 KV lines were returned to service and the safety related emergency buses were transferred to the startup transformer at 23:39. Operators subsequently terminated the UE at 23:47.

When the second 345 KV line was lost, a startup transformer lockout alarm was received in the control room. However, when the relays which actuate the lockout relay were checked, no flags were observed. Maintenance personnel were contacted and investigated the cause for the lockout. Until the cause for the lockout was identified, the startup transformer could not be returned to service, since plant procedures required the cause of the lockout to be known before the relay was reset. In order to facilitate thorough troubleshooting of the transformer, it was tagged out of service. An oil sample was taken to determine whether an internal fault had occurred and a megger was also performed. Both the megger and oil sample results were satisfactory and showed that the transformer was not damaged. Following these careful troubleshooting activities, the transformer was returned to service and energized at 23:39. The non-safety related buses were restored first to ensure that no problems were identified during the restoration which could damage the safety related buses. The inspector reviewed the associated alarm response procedure and discussed the lockout with the emergency director (operations manager) and determined that the lockout relay is actuated when a differential phase condition, ground differential condition, or phase overcurrent condition occurs. Through discussion of the cause of the lockout with engineering personnel, the inspector learned the cause of the lockout was believed to be actuation of one or more of the differential trip relays during the storm.

At 06:02 the control room received RHR and RCIC quadrant leakage alarms. At 06:55 the inspector observed operators appropriately enter EOP-4, Secondary Containment Control, because approximately 3 inches of water was found on the floor of the "B" quadrant, which contains the "B" core spray pump, "B" and "D" RHR pumps, and associated piping and components. The entry condition for EOP-4 is one inch or greater of water in any quadrant. The water was believed to be accumulating from normal building leakage into the reactor building drain system. Upon the loss of non-safety related buses, the reactor building sump pumps were also lost therefore the water could not be pumped out of the building. The de-energization of the non-safety related buses also took fuel pool cooling (FPC) out of service since they are the power supply for the FPC pumps. BECo had developed procedures to supply temporary power to the buses associated with these systems and these procedures were entered in a timely manner. The inspector observed periodic reports to the control room on quadrant water level and fuel pool temperature. Power was restored to the fuel pool cooling pumps at approximately 09:30 with a total heatup of six degrees. This rise in temperature was not significant and did not affect the safety of the fuel in the fuel pool. At 12:17 power was also restored to the reactor building sump pumps which were then energized and started, allowing operators to exit EOP-4 at approximately 14:11. The water level in the "B" quadrant room did not rise above 4 inches, well below the 21 inches evaluated in PNPS pipe break and flooding analyses. There was no damage to the emergency pumps as a result of the water on the floor.

The inspector attended the event critique conducted on April 2 which was attended by appropriate operations, emergency preparedness, maintenance, engineering and licensing personnel. The critique was led by the deputy plant manager and thoroughly discussed the sequence of events, current plant status, and immediate corrective actions. The various departments communicated well to understand how the plant equipment operated and identify potential problems. The critique report was detailed and covered the information presented at the critique. The report also listed several areas or events that required further action. The inspector verified that all corrective actions listed were assigned a due date and owner. The inspector noted that items were tracked via a PR or other method.

c. Conclusions

Operators responded well to the unusual event due to the complete loss of offsite power on April 1. Effective command-and-control was demonstrated by appropriate declaration of an Unusual Event, entrance into EOP-4, and presence of the emergency director in the control room. The decision to remain in the UE after the 23 KV line was restored, pending restoration of the 345 KV lines and stability in the lines, showed a prepared approach. Operators closely followed appropriate procedures to restore temporary power to non-safety related equipment to exit EOP-4 and restore fuel pool cooling.

O2 Operational Status of Facilities and Equipment

O2.1 Station Blackout Diesel Generator Failure During Loss of 345 KV Power

a. Inspection Scope (71707)

Approximately six hours after the main transformer failure on March 7, the station blackout diesel failed to run when operators attempted to start it. The inspector discussed the condition with operators that night, subsequently reviewed applicable procedures and corrective actions, and discussed the event with the system engineer and operations personnel.

b. Observations and Findings

Approximately six hours after the main transformer was lost on March 7, operators attempted to run the SBO diesel which subsequently tripped due to low oil pressure. The SBO diesel auxiliaries were powered by non-safety related sources which were lost when the main transformer failed. The auxiliary systems serve to keep the diesel ready to start and include the lubricating oil pump and jacket water immersion heaters. Operators attempted to start the diesel to ensure the auxiliary systems would keep the diesel warm enough for the diesel to be available if required during the event. Precaution number 7 in

Procedure 2.2.146, Station Blackout Diesel Generator, Revision 13, dated 10/24/95, stated, "On a loss of off-site power the SBO DG maintenance MCC B40 will not be powered. During cold weather this could affect the availability... Consideration should be given to running the SBO DG to power MCC B40." Through subsequent discussion with the system engineer and NWE, the inspector determined that early in the event the NWE realized the auxiliaries were lost and contacted the system engineer for guidance on when to run the diesel to ensure availability. The system engineer recommended running the diesel when the jacket cooling water temperature decreased to 60 degrees Fahrenheit. Through review of the SBO DG daily surveillance and discussion with engineering personnel, the inspector determined SBO jacket water temperature is maintained at 80 to 130 degrees.

At 21:04, operators received a low jacket water temperature alarm at which time the temperature was approximately 76 degrees. At 21:25 operators' attempt to start the diesel failed when the diesel tripped on low oil pressure. PR 97.9182 was issued for the diesel failure and the appropriate limiting condition for operation was entered. The SBO diesel, upon a loss of the 23 KV line, may be used to supply power to the shutdown transformer and one of the two safety-related buses. The loss of the SBO diesel reduced the redundancy of power available to the A5 and A6 buses. Although the weather conditions were not an obvious threat to the offsite line (i.e., winds were calm and no storm was expected), the potential existed for a loss of all power to the A5 bus. The inspector determined that procedure 2.2.146 was inadequate in that it did not provide sufficient guidance on how to maintain the SBO available upon the loss of its auxiliary bus.

BECo took timely corrective actions to revise the procedure via an SRO change such that the diesel was available throughout the complete loss of offsite power experienced on April 1 as discussed in Section I.O1.3. The SRO change, completed on March 31, added Section 7.4, Starting and Running the SBO DG at Idle, to provide instruction to operators. Precaution statement 7 was further revised to provide additional guidance on when the diesel should be run. The revision used the values for starting air pressure and jacket water temperature which are verified during the daily operator tour. The additional SRO change added flexibility for the operators to secure the diesel after these values are met to preclude running the diesel for unnecessary extended periods of time. Procedure 2.4.16 was also revised to direct operation of the SBO when a sequential or partial loss of offsite power occurs. In addition, the Vice President of Nuclear Operations and Station Director has committed to modify the plant to supply independent power to the SBO diesel auxiliaries by the end of March 1998. This licensee identified and corrected violation is being treated as a Non Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

On April 18, the NRC issued Information Notice (IN) 97-21, Availability of Alternate AC Power Source Designed for Station Blackout Event to inform licensees of the potential unavailability of alternate power supplies during SBO events including the March 7 event at PNPS.

c. Conclusions

Although operators were aware of the loss of auxiliary power to the SBO diesel after the main transformer failure, actions were not timely enough to prevent loss of the SBO diesel availability. This resulted due to an inadequate procedure and ineffective interface with the system engineer.

O4 Operator Knowledge and Performance

O4.1 Plant Restart and Power Ascension

a. Inspection Scope (71707)

Portions of plant restart and power ascension activities were monitored, including deep back shift inspection, to observe operations department and overall equipment performance following RFO11.

b. Observations and Findings

On April 10, the inspector attended a day long, readiness for restart meeting conducted in accordance with Mission Organization & Policy (MOP) procedure D.3.6, Committee Charters. Prior to the start of the meeting, no written material was specifically available to the NMC members in preparation for the meeting. The inspector also noted that MOP D.3.6 provided sparse general guidance including the timeliness of conducting the meeting relative to restart.

At the meeting, various managers made presentations to the nuclear managers committee (NMC) on the status of each departments major work completed, work outstanding and work deferred from RFO11. The department briefings were detailed and insightful. One discussion involved the status of scaffolds left erected adjacent to safety related equipment. The inspector did note small progress in the reduction of longstanding scaffolds adjacent to safety related equipment. For example, a longstanding scaffold erected around a sensitive instrument rack located on the 51 foot elevation of the reactor building was removed. This scaffold was removed because BECo erected a permanent work platform in the same location. However, significant scaffolds remained erected in the "A" RHR quadrant room which were intended to be addressed as part of the continuing plant upgrade process.

Special emphasis was placed on resolution of safety related issues. The engineering staff briefed the NMC on degradation of the seawater side of the "B" reactor building closed cooling water (RBCCW) heat exchanger. After a significant storm on April 1, 1997, the resistance of the seawater side of the "B" heat exchanger significantly increased. Operations personnel performed several backwashes but were unable to substantially clear the potential macrofouling. Problem report 97.9261 was generated to document the problem, evaluate and obtain corrective actions. Engineering personnel generated a new flowrate versus DP curve that provided more operational flexibility. After the readiness for restart meeting, the inspector reviewed the performance data for the "B" RBCCW heat exchanger. The inspector was concerned that the increase in system resistance of the seawater side of the "B" RBCCW heat exchanger experienced during the storm was not initially alleviated by the backwashes. At this point, the inspector considered this a restart issue even though engineering personnel analyzed that the degradation was acceptable based on the new operability curve. After further backwashes, the "B" RBCCW heat exchanger performance improved significantly returning more margin to operability.

Operators brought the reactor critical at 7:53 pm on April 14, 1997. The inspector observed the approach to criticality and plant heat-up. Nuclear instrumentation (i.e., SRMs & IRMs) performed reliability during the start-up including the overlap period between SRM and IRMs. The inspector noted that the reliable performance of the SRMs and IRMs reflected positively on the I&C and engineering staffs. Proper use of procedures was observed and evidence of operations department management oversight. Operations support personnel interfaced effectively with members of the operating crew on reactivity control management. Portions of the reactor core isolation cooling (RCIC) and high pressure coolant injection (HPCI) testing were observed with no problems identified. One inadvertent trip of the RCIC turbine resulted from a design control issue further discussed in the engineering section of this report.

Two significant equipment/system issues emerged during the start-up which adversely affected operational activities. Operators experienced great difficulty in the initial movements (i.e., positions 00-04, 04-08) of several control rods. Increased drive water pressure was routinely needed to free the control rods from the full-in position of 00. After initial rod movement, the control rods generally moved satisfactorily. Two control rods under a withdrawal signal actually inserted. Also, another control rod moved too rapidly when withdrawn. The inspector observed proper operator response to each control rod anomaly. Needle valve adjustments at the hydraulic control unit manifold corrected the adverse conditions and start-up proceeded.

The inspector interviewed operators and the control rod drive (CRD) system engineer to determine the cause of the sluggish performance of the initial control rod movement and the three aforementioned individual control rod problems. The inspector learned that control rod stroke time testing, not to be confused with control rod scram time testing, was initially in the outage schedule but was removed from the schedule during the outage. Stroke time testing per procedure 2.2.87, Control Rod Drive System, Section 7.11, Drive Speed Adjustment was not performed during RFO10 or RFO11. The stroke time testing ensures proper needle valve settings and allows for removal of air from the system. Problem report 97.9279 was initiated to address the sluggish performance of the initial control rod movement which was assigned as a significant condition requiring a formal root cause.

A second equipment issue which became an operational impact during start-up and power ascension involved the feed water system regulating valves (FRVs). At lower power level with one feed pump in service, large swings of approximately 1.3 million pounds mass/hour in feed water flow were observed. Actual changes in reactor vessel water level were minimal. The swings in feed water flow lessened as power was increased to 100%. Operators responded effectively to the oscillations by immediately informing engineering personnel and initiating a problem report to obtain corrective action. The inspector expressed concern that the feed flow oscillations could adversely affect the next significant downpower or shutdown. During the shutdown to enter RFO11, a feed water system regulating valve malfunction resulted in a manual reactor scram. Plant management again initiated an interdisciplinary team to solve the feed water control system problems. The degraded conditions associated with the FRVs and sluggish control rod movement constitute an unresolved item (**URI 97-02-01**) pending further BECo engineering and NRC review.

The inspector entered the drywell with operations and maintenance personnel for the final close-out inspection at 1000 psig reactor pressure. A detailed briefing was conducted by radiological protection (RP) technicians and the use of neutron dosimetry was required. Four of the drywell-to-torus downcomers were visually examined to confirm no foreign material existed that could impede water/steam flow during a postulated accident. No loose fibrous material was observed in the drywell. The inspector identified several minor deficiencies during the close-out inspection with the most significant involving water leakage from control rod drive (CRD) 34-03 at a rate of one drop/3 seconds. Closer examination of the source of the leakage by the maintenance department manager determined the leakage originated from top side of the lower CRD bolted flange and not from the core vessel stub tube region. Some small items such as discarded weld rods, nuts, bolts, and washers were observed laying loose on the different elevations in the drywell. The inspector determined during the drywell close-out inspection that the downcomers were free of foreign material, no loose fibrous material existed and some minor deficiencies were identified. RP personnel provided a thorough briefing prior to the entry and accompanied the inspection team into the drywell.

Operators synchronized the generator onto the electrical grid for a four hour warm-up period prior to the start of turbine overspeed testing accomplished by procedure 8.2.1, Turbine Overspeed Testing. The inspector observed the entire portion of overspeed testing and re-synchronization of the generator back onto the electrical grid. Two tests of the back-up overspeed trip and three tests of the emergency governor overspeed were successfully completed as required. The test results during redundant test were almost identical and within band. Strengths noticed during the test included strong command-and-control by the nuclear operating supervisor (NOS) who was qualified and very experienced as a nuclear watch engineer (NWE). Also contributing to the effective communications was the effectiveness of the new portable cellular phones which was a significant improvement. Reactor operators performed switch manipulations using effective self checking techniques throughout the evolution. There was clear evidence of operations department, plant and senior management presence in the control room. Operations personnel interfaced smoothly with the General Electric turbine specialist. Operators closely monitored turbine vibrations especially on the no. 6 bearing which reached a maximum reading of 9 mils. The test procedure properly contained clear abort criteria for high turbine vibrations. Excellent operator performance was observed during the turbine overspeed testing.

Four attempts by the reactor operator were necessary to synchronize the generator back onto the electrical grid. After a few attempts, the operator increased the speed of the synchroscope needle based on advice from the NWE. The inspector interviewed the operator who explained that he had performed the evolution once before in two attempts. Operations management and training personnel informed the inspector that the personnel had received specific training on the simulator including synchronization of the generator onto the grid. The inspector determined that the multiple attempts needed to resynchronize onto the electrical grid reflected an operator weakness. However, operator training personnel later informed the inspector of the need for increased training when synchronizing onto the grid including a detailed review of the out-of-phase block function. Operators completed power ascension returning the unit back to 100% power without incident.

c. Conclusions

The readiness for restart meeting effectively reviewed numerous issues prior to restart. Operators performed start-up and power ascension activities in a professional and controlled manner with due regard for nuclear safety. A few minor deficiencies were identified by the NRC during the final drywell close-out inspection performed with reactor pressure at 1000 psig. Two equipment/system degraded conditions **(URI 97-02-01)** involving the degraded operation of control rods and feedwater system regulating valves impacted operational activities during start-up and power ascension from RFO11. Strong operator command-and-control was evident during the turbine overspeed testing. Four attempts were needed to re-synchronize the generator back onto the electrical grid due to an operator training weakness.

O8 Miscellaneous Operations Issues (92700, 92901)

O8.1 (Closed) LER 95-003: Manual Scram Due To Main Generator Stator Cooling Water Temperature Control Valve Failure

On March 24, 1995, failure of the main generator stator cooling water (SCW) system temperature control valve resulted in rising temperature on the main generator. Coincident with immediate SCW system troubleshooting actions, operators reduced reactor power to mitigate the condition in preparation for a possible reactor scram. Despite prompt operator action to correct the condition, a manual reactor scram was inserted at 60 percent reactor power, when temperature continued to rise to the point of causing an automatic generator runback. Details of this event are discussed in inspection report 95-07.
BECo determined that the root cause of this event was failure of a mechanical linkage in the SCW temperature control valve controller. Specifically, two components of the linkage (a threaded rod and a nylon connector) separated, which resulted in the controller failing to the full bypass position. As corrective action, the controller was replaced.

The inspector concluded that the licensee's corrective action was appropriate and that the failure of the controller could not reasonably have been anticipated because the unit had only been in service for two years. Based on this review, along with the assessment of operator response to the event as presented in inspection report 95-07, this LER is closed.

II. MAINTENANCE

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (61726, 62707)

Using inspection procedures 61726 and 62707, 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:

- TP 97-030 ECCS Suction Strainer Postwork Testing
- 2.1.8.5 Reactor Vessel Pressurization and Temperature Control for Class 1 System Leakage Test
- 8.M.3-1 Special Test for Automatic Load Sequencing of Diesels and Shutdown Transformer With Simulated Loss of Off-site Power
- 8.2.7 Special Test for Shutdown Transformer Load Test
- 8.5.6.2 Special Test for ADS System Manual Opening of Relief Valves

b. Observations and Findings

All pre-evolution briefs (PEBs) were thorough and clearly communicated the purpose and sequencing of testing. Proper self-checking and effective communication were stressed. The inspector observed knowledgeable operators and maintenance and instrumentation and controls (I&C) technicians perform activities in accordance with approved procedures. Prior to performing procedure 8.5.6.2, a communications check and dry run of the procedure was performed to ensure each participant understood their function and responsibility. As a result, the test was completed satisfactorily and the safety relief valves were opened for the shortest amount of time possible.

Per the PNPS inservice inspection program, a complete hydrostatic test of the reactor pressure vessel was not required this refueling outage; therefore, a Class 1 system leakage pressure test of the reactor vessel was conducted at approximately 1050 psig. The inspector observed a PEB for procedure 2.1.8.5 on March 26. The briefing was attended by appropriate operations, engineering, and quality control personnel as well as the operations manager. The brief thoroughly discussed chain-of-command and progression through the procedure The inspector discussed the visual inspection with the VT-2 certified quality assurance inspectors who performed the inspection. The QA inspectors were knowledgeable of the test and their responsibilities. The inspector specifically confirmed that the inspectors were aware of their responsibility to check the connection points of the chemical decontamination equipment in the drywell, used during RFO 11. The inspector determined that the required inspection points were well understood by BECo personnel. Due to inadequate readings of the vessel flange thermocouples, the pressurization test was delayed a few days. PR 97.1487 was issued to document the low readings on all flange temperature elements. A temporary modification was installed to allow operators to read the actual vessel temperature at the drywell entrance. Prior to restart, the temporary modification was configured to provide flange temperature in the control room. This modification will remain in place until RFO 12, when new, permanent temperature elements are planned to be installed. The inspector reviewed the results of the leak inspection performed on March 29 and determined that the inspections were thorough and identified various leaks which were evaluated and corrected as necessary prior to restart.

Procedures 8.2.7 and 8.M.3-1 were performed together on the evening of April 8. The PEB was attended by the operations manager who stressed clear communication and taking the time to perform it correctly, asking questions if necessary. The test director reviewed the reason for the two tests and their sequencing. Operators exhibited a questioning attitude during the briefing which prompted operations to prepare a tagout to open main steamline drains when the reactor pressure vessel head vents closed during the procedure. PR 97.1608 was written to document the need for a review of the procedures for completeness. Also, since these two tests are typically performed together, the PR will address combining the two into one to reduce the sequencing effort required. The tests were generally well performed and effective test control was maintained. Personnel stopped the test when discrepancies were noted and systems were returned to their normal lineups after test completion.

During a review of chart recorder data after the tests were performed, the test director discovered and the inspector observed that data was missing from the recorder in the control room. Temporary chart recorders were installed for the test to provide data on diesel loading, breaker closure times, etc. The failure to gather this data required portions of 8.M.3-1 to be re-performed. PR 97.1802 was written to document this error.

c. Conclusions

Pre-evolutionary briefs for observed tests were thorough and stressed procedure adherence, proper chain-of-command and self-checking. Operations management was often present to provide oversight and stress the importance of several of the tests performed. The questioning attitude of an operator during an ECCS load sequencing with loss of offsite power test prompted better preparation for the test and further review of the procedure for improvement. Degraded reactor pressure vessel flange temperature elements delayed the reactor pressure vessel leakage test and required a temporary modification to be installed prior to startup. Portions of the test were reran when a recorder was not turned on.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Reactor Feedwater Pump Motor Heater Failure

a. Inspection Scope (62703)

The inspector reviewed the circumstances surrounding a small electrical fire that occurred in the "B" reactor feedwater pump (RFP) motor, including BECo's cause determination and corrective actions.

b. Observations and Findings

On March 23, 1997, an operator observed smoke coming from the "b" RFP motor. At the time, the motor breaker was removed and the main line conductors were grounded for maintenance protection, so 4160 VAC power was not present at the motor; however, the 240 VAC motor heaters had been energized for approximately 24 hours. Plant personnel responded by de-energizing the motor heaters, which eliminated all electrical power from the motor. The small electrical fire was extinguished using portable chemical and carbon dioxide fire extinguishers. BECo estimated that the fire lasted two minutes. Subsequent inspection revealed that the motor heaters had short circuited. Arcing had apparently ignited residual oil inside the motor casing, and fire then spread to insulation on the motor main power cables and the sealant used in the floor cable penetration. No emergency classification (i.e., unusual event) was required. The event was not reportable.

The licensee initiated problem report (PR) 97.9226 to determine the root cause of the event. Prior to completion of this evaluation, the licensee determined that all RFP motor heaters should be replaced; this action was completed prior to plant startup. Electrical testing of the "B" RFP motor indicated that the motor had not been damaged during the event. However, given the age of the motor, along with its being contaminated by soot and chemical fire extinguishing agent, the licensee concluded that it should be cleaned The portions of the three main power cables that had been damaged by fire were also replaced. Sealant in the floor cable penetrations for all three RFPs was replaced with a flame retardant material. The restored "B" RFP motor was re-installed on April 27.

The inspector questioned whether motors in safety related applications had been examined as part of the preventive maintenance program for susceptibility to motor heater failure. Motors for pumps in the emergency core cooling systems (ECCS) had been examined during 1996 with no similar problems identified, and testing of the motor heaters was a part of this examination.

c. Conclusions

The BECo response to a fire in the "B" RFP motor was timely and effective. Short term corrective actions were thorough and addressed the apparent cause (degraded motor heaters) for all three RFPs. Existing preventive maintenance on safety related pump motors provides reasonable assurance that these motors are not susceptible to similar failure.

M2.2 Main Transformer Replacement

a. Inspection Scope (62707)

Following the main transformer failure on March 7, BECo determined that the old transformer would not be practical to rebuild. Therefore, through a prearranged agreement with Northeast Utilities, BECo transported a spare transformer from the Millstone Nuclear Generating Station and installed it at PNPS. The inspectors observed portions of the main transformer transfer, installation, and operation.

b. Observations and Findings

The transfer and replacement involved extensive time and coordination between the two sites and between the PNPS engineering and maintenance departments. The inspectors observed careful transfer of the new transformer from Millstone to Pilgrim. Extensive hold-down equipment was used to ensure that the transformer would not be separated from the barge which carried it into the boat launch area at Pilgrim. In addition, modifications were made to the boat launch area including temporary improvement of the road to the ramp and construction of a ramp from the barge to the road. The inspector also noted that open ports of the new transformer were sufficiently covered to protect the internals from weather and foreign material intrusion.

Engineering developed and maintenance implemented design changes to the transformer and existing isophase ductwork to allow the new transformer to be installed on the same pad the old transformer had occupied. The new transformer is larger than the old, rated at 880 MVA and 784 MVA, respectively. Therefore, modifications were required. The inspector discussed the related calculations performed with engineering personnel and confirmed that the voltage rating for the two transformers were the same (i.e. high voltage winding rated at 345 KV and low voltage winding rated at 23 KV) and appropriate electrical calculations were reviewed and revised as necessary with the specific attributes of the new transformer.

The isophase ducting was modified to include drains to prevent oil from gravity draining into the turbine building upon a transformer failure as it did on March 7. The inspector walked down the transformer and verified these modifications were made. No leaks or other problems were identified during the walkdown. The transformer was post work tested and subsequently successfully energized on April 21.

c. Conclusions

Efforts to transport, install, modify and ultimately energize the new main transformer, following the failure of the original transformer on March 7, reflected good overall control by the maintenance and engineering staffs. Careful transportation, appropriate electrical calculation revisions, and required modifications to associated equipment were verified which facilitated successful energization on April 21.

M3 Maintenance Procedures and Documentation

M3.1 (Closed) LER 97-006: Unexpected Shutdown Cooling Isolation During Troubleshooting

a. Inspection Scope (62707)

During troubleshooting activities on March 21, 1997, an unexpected isolation of the shutdown cooling mode of residual heat removal occurred. The inspector discussed the event with station personnel and reviewed the associated procedure and Licensee Event Report (LER) 97-006, Inadvertent Group 3 Isolation While Troubleshooting a 125 VDC Ground on the "A" Battery.

b. Observations and Findings

On March 21, 1997, maintenance personnel used procedure 3.M.1-34, Generic Troubleshooting & Maintenance Procedure, to troubleshoot a 125 VDC "A" battery alarm which had been received in the control room earlier that day. The 3.M.1-34 directed personnel to cycle breakers on panel D4. Prior to the troubleshooting, the "B" RHR pump was operating in the shutdown cooling mode. Circuit breaker D4-8 was opened and then closed per 3.M.1-34. Upon re-closure, motor-operated valve MO-1001-50, shutdown cooling inboard isolation valve, automatically isolated and the "B" RHR pump tripped as a result. Operators entered procedure 2.4.25, Loss of Shutdown Cooling, and re-established shutdown cooling in approximately 24 minutes. No increase in the moderator temperature of 85 degrees Fahrenheit was observed as a result of the isolation.

LER 97-006 stated the isolation resulted from a "relay race" when the breaker was cycled. Prior to granting approval for the troubleshooting to commence, the nuclear operating supervisor (NOS) reviewed the troubleshooting plan and procedure 2.2.14, 125 ADC Battery Systems, for the effects to the plant when opening the proposed breakers. The inspector verified that the procedure did not mention the potential for the closure of the 1001-50 valve upon closure of the breaker; it only stated that the Group 3 RHR isolation relays would not function for the 1001-50 valve, to isolate the system when the breaker was opened. The unanticipated condition was when the breaker was closed, two relays timed out in a sequence resulting in the closure of valve 1001-50.

The LER stated, and the inspector confirmed, that the isolation occurred because of a procedure deficiency in which BECo personnel failed to recognize the potential for the shutdown cooling isolation during this evolution. The purpose of procedure 2.4.45, which the NOS reviewed prior to approving the troubleshooting activity, is to provide, "..a detailed instruction for Operations personnel for operating the 125 VDC Battery System..." However, this procedure did not state the effect of re-closing this breaker.

Operators responded appropriately to the unexpected isolation and restored the system within 24 minutes with no adverse effect on moderator temperature. In addition, BECo stopped the troubleshooting activity and reviewed the troubleshooting plan prior to recommencing the maintenance to preclude this isolation or a similar occurrence. The inspector verified at that time that the shutdown cooling isolation outboard valve, which was susceptible to the same isolation, was not part of the troubleshooting plan and the D4-8 breaker would not be cycled again. Procedure 2.2.14 was also revised prior to the resumption of work and incorporated notes for both the inboard and outboard isolation valves. PR 97.9220 was issued to document the event. A formal root cause evaluation was assigned to the maintenance department but was not yet completed prior to the end of this report period. This licensee identified and corrected violation is being treated as a Non Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

c. Conclusions

A brief loss of shutdown cooling (LER 97-006) resulted from inadequate procedure 2.2.14. BECo corrective actions were appropriate to the circumstances.

M6 Maintenance Organization and Administration

M6.1 Refueling Floor Maintenance Activities

a. Inspection Scope (36800, 62707)

After the completion of in-vessel work during RFO11, portions of the reactor reassembly process were observed including evaluation of significant problems experienced. During the reactor disassembly process the newer vintage vessel stud nut tensioners failed to work as documented in NRC inspection report No. 97-01, Section M6.1.

b. Observations and Findings

Reactor vessel reassembly activities progressed well. Some difficulty was experienced when lowering the moisture separator back into the vessel using procedure 3.M.4-48.3, Vessel Reassembly. Members of the refueling crew observed that a main steam line (MSL) plug seal piston actuator shaft broke off and fell down into the vessel. This created an adverse foreign material exclusion (FME) condition with a loose part in the vessel. Problem report 97.9203 was generated to document, evaluate and correct the condition. BECo management directed that the steam separator be removed from the vessel and the loose part retrieved. Upon closer inspection, all main steam line plugs were physically damaged through contact with the moisture separator. The loose part was retrieved from the vessel and reassembly activities continued. The action to retrieve the loose part rather than perform a loose part evaluation accepting the adverse condition reflected a proper focus on safety principles.

The inspector reviewed procedure 3.M.4-48, Section 8.6, Installation of Steam Separator, and interviewed various members of the refueling management team and outage management to determine the potential cause for the physical contact between the steam separator and main steam line plugs. Procedure 3.M.4-48 did not specifically address the configuration of the MSL plugs during installation of the steam separator. The event revealed that the MSL may be installed during steam separator installation but not pressurized since the actuator shaft sticks out an additional 9 inches for each plug. Pressurizing the plugs placed the actuator shaft in the travel path of the steam separator which lowers down into the vessel on guides. The inspector concluded that refueling procedure 3.M.4-48 was inadequate by not addressing steam separator installation with MSL plugs installed and pressurized. This licensee identified (through the event) and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

At the time of the event, all four MSL plugs were installed and pressurized with air. The decision was made prior to the event by outage management and the refueling management group to leave the MSL plugs installed and pressurized based primarily on input from the MSL plug vendor and also the GE refueling manager. The rationale for leaving the MSL plugs installed was to allow continued work on the downstream main steam isolation valves (MSIV) in parallel with installation of the vessel internals. The design of the MSL plugs was to provide a watertight seal to allow maintenance on the MSIVs without pressurization which was only required during the local leak rate test

(LLRT). Hence, the decision to leave the plugs pressurized after the LLRT when installing the vessel internals was intended to avoid any possible plug leakage into the maintenance area. The actual dimensions and clearances of the MSL plugs verses the vessel internals were never technically verified but rather based on vendor input form experiences at other BWRs. The inspector determined that the over-reliance on verbal vendor information and the lack of a detailed technical review of PNPS design drawings caused this event and the aforementioned procedure inadequacy.

After the internals were installed and the reactor vessel head lowered into place, the reactor vessel head stud nuts were tensioned using the new style tensioners. These tensioners failed during RFO10 and during disassembly in RFO11. The new tensioners worked smoothly with no problems experienced. An advantage of the new tensioners was less worker effort to operate the tensioners and less worker radiation exposure due to faster tensioner operation. BECo determined that the previous problems experienced with the new tensioners resulted from the tensioners becoming slightly cocked due to interference with the curvature of the reactor vessel head. Apparently, when the new tensioners were procured for RFO10, the dimensions of the reactor vessel head were based on drawings and not actual conditions. The slight taper of the head was offset by the use of a spacer which allowed the tensioners to load properly.

The refueling outage manager informed the inspector of a detailed lessons learned review scheduled to be performed. A written report will document the review results including positive attributes and opportunities to improve. A log book was maintained by the refueling floor manager with a listing of items for improvement.

c. Conclusions

The new vessel stud tensioners worked smoothly with no problems during vessel reassembly. This resulted in less manual effort required by the refuel crew workers and also less radiation exposure due to the efficiency of the new tensioners. Damage to all four main steam line plugs occurred with a resultant loose part falling into the vessel due to an inadequate vessel reassembly procedure. The procedural inadequacy resulted from an over-reliance on verbal vendor information based on experiences at other BWRs rather than a detailed technical review of design drawings to confirm the proper clearances between the steam separator and the plugs. However, a proper safety focus was evident by removing the separator and retrieving the loose part. An RFO11 lessons learned review was planned to develop what worked well and areas for improvement.

III. ENGINEERING

E2 Engineering Support of Facilities and Equipment

E2.1 De-energization of 120 Volt Safeguards Control Power Panels During Storm

a. Inspection Scope (37551, 92903)

Prior to the unusual event discussed in Section I.O1.3, the safety-related 120 Volt safeguards control power buses Y3 and Y4 de-energized while the safety related 4160 V buses A5 and A6 remained energized. The inspector reviewed operator logs and LER 97-07 and discussed the event with the electrical engineering manager.

b. Observations and Findings

On April 1 at 01:35 safeguards control power buses Y3 and Y4 were de-energized when regulating voltage transformers X55 and X56 de-energized. Y3 and Y4 supply power to the normally-energized control logic relays in PCIS and RBIS and pressure switches that monitor the header pressure of the salt service water (SSW) system and reactor building closed cooling water system (RBCCW). The de-energization resulted in a PCIS Group VI isolation (RWCU) and an RBIS isolation signal and resultant automatic start of the standby gas treatment trains. The SSW pump and RBCCW pumps that were in service at the time stopped. The Y3 and Y4 panels again de-energized at 0209. Operators took appropriate corrective actions after both losses and restarted the SSW and RBCCW pumps within 1 minute and reset the Y3 and Y4 buses, RBIS and PCIS, as appropriate.

The loss of power to panels Y3/Y4 was detectable, operator response actions were proceduralized, immediate safety functions were not adversely affected and the panels were powered in sufficient time to support longer term safety functions. Also, the manual start function for the affected SSW and RBCCW pumps was not affected.

BECo determined the panels de-energized because their voltage regulating transformers automatically shut down during short but severe storm-related undervoltage conditions, as low as 350 V at the regulating transformer. Two other voltage regulating transformers, X57 and X58, had the same design. X58 supplies part of the power for the "B" train of the post accident sampling system (PASS) and also shut down during the storm. X59 supplied power to the "A" train of PASS but was tagged out of service for maintenance when the storm occurred.

All four voltage regulating transformers were installed in 1992 per a design modification (PDC 91-59A). BECo had not been aware of the isolation feature because the design specification, E15A, did not require or prohibit an automatic shutdown on voltage transients less than 384 V and greater than 576 V. Further, the design documentation provided from the manufacturer did not identify the automatic shutdown feature at less than 384 V. The transformers were designed and tested to regulate input voltages from 384-576 with a specified output. The testing performed on the transformers did not envelope the low voltages experienced during the storm and therefore did not detect the trip setpoints. The human performance aspects of the cause of the deficiency in engineering specification E15A is being evaluated per PR 97.9245. Safety evaluation (SE) 2664 which accompanied the 1992 design modification did not evaluate the consequences of an undervoltage transient shutdown of the regulating transformers. PR 97.1658 was generated to document this problem and track associated corrective action. This failure to maintain adequate design control is the first example of a violation of 10 CFR Part 50 Appendix B, Criterion III, Design Control **(VIO 97-02-02)**.

In addition, PR 97.1778 was written to document the SSW and RBCCW pump shutdowns. As stated above, the voltages at the 480 V load centers were estimated at 322 and that at the MCCs powered by these load centers would have been less. The SSW and RBCCW pumps are fed from those MCCs and are set to trip at an MCC voltage of approximately 322 V.

Prior to restart, BECo modified the voltage regulating transformers and disabled the undervoltage and overvoltage shutdown functions, by replacing the microprocessor control units. When incoming voltage falls outside the design range these transformers will operate in the unregulated mode.

c. Conclusions

The unexpected automatic isolation of the 480/120 V regulating transformers resulted from brief and severe undervoltage transients during a winter storm. The reason the isolations were unexpected was that the design documentation did not specify the isolation function of the transformers on under/overvoltage. This failure to maintain adequate design control is the first example of a violation of 10 CFR Part 50 Appendix B, Criterion III, Design Control **(VIO 97-02-02)**.

E2.2 RCIC Turbine Overspeed Trip

a. Inspection Scope (37551,93702)

During start-up from RFO11, the RCIC system turbine tripped on overspeed during full flow surveillance testing. The inspector monitored the troubleshooting effort and reviewed the cause. Problem report 97.9290 was generated to review the event, determine cause and corrective actions. The requisite 10 CFR 50.72 NRC formal notification was made and a 10 CFR 50.73 report was initiated.

b. Observations and Findings

Evaluation of RCIC system EPIC computer traces revealed that MO-1301-53, Full Flow Test Valve, went full shut after being jogged briefly in the shut direction from the full open position. As a result, the RCIC turbine speed control system continuously increased, in an attempt to establish 400 gallons/minute, that led to the overspeed trip. Prior to RFO11 MO-1301-53 functioned as jog open/jog close. Electrical maintenance personnel inspected MO-1301-53 which was wired in the field to function as a jog open/seal-in close valve. Electrical design drawing MIG27 depicted MO-1301-53 as jog open/seal-in close; however, the valve had been previously modified at an indeterminate date to function as jog open/jog close and design drawing MIG27 was never updated. As part of the corrective actions taken after the turbine trip, FRN 93-38-21 was issued and implemented to reconfigure the breaker assembly so MO-1301-53 functioned as jog open/jog close. The RCIC system turbine subsequently passed full flow testing and was declared operable. Additionally, design drawing MIG27 was modified to reflect the change which included the removal of an electrical jumper from terminal board (TB) 4 to TB 14 in the new breaker cubicle D781. The modification made during RFO11 was to address potential degradation of electrical contacts as discussed in NRC Generic Letter 89-10. Problem report 97.9290 was initiated which included a review to determine the underlying cause.

BECo initiated a review to determine when the potential undocumented modification was made. Engineering personnel verified the undocumented modification by examining the old breaker assembly which was replaced during RFO11. The inspector determined that the undocumented modification to the breaker assembly was not reflected in drawing MIG27 and was the second example of a design control violation **(VIO 97-02-02)** of 10 CFR 50, Appendix B, Criterion III, Design Control. Criterion III requires that measure shall be established to ensure that the function of a component are correctly translated into drawings. The inspector noted that this error resulted in an unnecessary challenge to the RCIC turbine and also increased RCIC unavailability time. The electrical engineering department manager acknowledged these concerns. A preliminary problem bounding review determined that the problem only had the potential to exist in the HPCI system full flow test valve; however, a field verification of the same valve in the HPCI system identified no problem.

c. <u>Conclusions</u>

Inadequate electrical configuration involving the breaker for MO-1301-53 resulted in an unnecessary challenge to the RCIC system turbine and increased safety system unavailability time. The overall RCIC unavailability time still remained very low. This failure to maintain adequate design control is the second example of a violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control **(VIO 97-02-02)**.

E3 Engineering Procedures and Documentation

E3.1 ECCS Torus Suction Strainer

a. <u>Inspection Scope (37551)</u>

After successful full flow post modification testing and return to service of the new larger ECCS suction strainers, rework of three slip joints was required to restore critical clearances. The inspector reviewed the issues associated with the slip joint rework which resulted in an additional 5 REM of radiation exposure. Installation of the new strainers was a challenge due to the emerging nature of the issue, the need for substantial underwater work in the torus and general lack of industry experience in completing the task.

b. Observations and Findings

Each of the two ECCS suction strainer assemblies installed in the torus underwater had three suction lines connected for two RHR pumps and 1 CS system pump. Each of the six total suction lines connected to the strainers incorporated a slip joint design to accommodate for movement to ensure loads were not adversely transferred to the torus shell. After completion of physical work and with the strainers turned over to operations for service, engineering personnel requested an underwater videotape of the slip joint areas. Three of the six slip joints were found misaligned. The spool pieces had to be slightly twisted, marked, removed from the water, new bolt flange holes drilled and reinstalled. A fourth slip joint was also reworked to provide increased clearance margins. The inspector considered the identification and restoration of the proper slip joint clearance margins reflected a proper BECo safety perspective.

The inspector interviewed key BECo personnel and paperwork associated with the ECCS strainer project to determine the cause for the slip joint rework. A vendor (WSI) was contracted to fabricate and install the strainer. BECo had not determined the final root cause but preliminarily determined that the cause involved the templating method used to fabricate the spool pieces between each strainer assembly and the pump suction lines. A special tool was used underwater which generally consisted of two angled mating surfaces connected by two long rods that could be pressurized between the strainer assembly and pump suction line flange to form a template. BECo believed that the template must have moved or cocked when pressurized therefore affecting the measurements for the spool piece fabrication. Alignment pins at each end of the template tool were used in lieu of bolts. The alignment pins potentially allowed movement of the mating surfaces when pressurized adversely affecting dimensions for fabrication. At the end of this inspection period, BECo was interfacing with WSI to substantiate this potential cause.

Several other ancillary issues became evident that may have led to earlier identification of the slip joint clearance issues. First, the design drawing (C1A360) for the strainer slip joint showed centerline-to-centerline fit-up with no notation of the critical nature of the clearances. As a result, the inspector learned that the BECo project implementation staff and torus divers assumed that the slip joint clearances was a device to allow construction fit-up of the spool pieces. Second, the vendor quality assurance (QA) personnel did not detect the slip joint misalignment primarily because no specific hold point was required and only remote video camera monitoring was available of the underwater work. Third, the design engineer and BECo QA did not review the inspection plan prepared by the vendor QA personnel. BECo QA personnel were more actively involved during the procurement phase of the strainer parts and the torus drywell close-out process. The inspector determined that these ancillary weaknesses contributed to the late identification of the problem. The BECo design engineer, project manager and engineer, and BECo quality assurance personnel agreed with these lessons learned.

c. Conclusions

Five REM of additional radiation exposure was used to rework several of the ECCS suction strainer slip joints that were misaligned. A preliminary review determined the likely cause involved a weakness in the templating and fabrication process. Although engineering personnel identified the misalignment by watching a videotape, the engineering design documents did not highlight the critical nature of the slip joint clearances. As a result, the project implementation staff assumed the clearances were for construction fit-up; and, also, vendor QA personnel did not have a specific hold point inspection requirement. The design engineer and BECo QA personnel did not review the vendor inspection plan.

E7 Quality Assurance in Engineering Activities

E7.1 Core Shroud Vertical Weld Inspection Results

a. Inspection Scope (37551, 92903)

A review of the results of the PNPS core shroud inspection was performed to determine any obvious applicability of the issues described in NRC Information Notice 97-17, Cracking of Vertical Core Shroud Welds and Degraded Repair. BECo's core shroud inspection plan was submitted to the NRC along with the ISI Plan submittal for RFO11, dated October 30, 1996. The plan specified, in part, ultrasonic inspection of accessible portions of 25% of the equivalent length of all vertical welds (approx. 134 inches) from the vessel internal diameter. Also, a VT-3 examination of one complete tie rod and a VT-1 inspection of welds at one gusset plate.

b. Observations and Findings

During this inspection period in RFO11, BECo inspected, in part, vertical core shroud welds V-17 and V-18 which were comparable to the same weld locations at NMP1 in the core beltline region. An equivalent weld length of 138.75 inches was examined. No reportable indications were recorded during the ultrasonic examinations of the V-17 and V-18 core shroud vertical welds. Further, inspection of one complete tie rod and gusset plate welds revealed no notable problems. The inspector interviewed several engineering and quality assurance personnel and determined that BECo personnel knew of the NMP1 issues and were closely following the developments as well as any potential generic implications.

c. Conclusions

Ultrasonic examinations performed during RFO11 as part of the core shroud inspection plan revealed no reportable indications of V-17 and V-18 vertical welds. Engineering and quality assurance personnel promptly evaluated industry experience on core shroud issues that were identified at NMP1 as documented in NRC Information Notice 97-17, dated April 4, 1997.

E8 Miscellaneous Engineering Issues

E8.1 Inservice Inspection

a. Inspection Scope (73753, 92903)

The objective of this inspection was to determine that the inservice (ISI), repair, and replacement of Class 1, 2, and 3 pressure retaining components are performed in accordance with the Technical Specification (TS), the applicable ASME Code, NRC requirements, and industry initiatives, including any relief requests granted by the NRC.

The scope of the inspection included the review of the licensee's ISI program plan for Pilgrim Station, procedures, qualification of inspection/examination personnel, schedule of planned ISIs for the refueling outage 11, and observation of ISI work.

b. Observations and Findings

1. The Third Ten-Year Interval for the Pilgrim Nuclear Station Inservice inspection began on July 1, 1995. The licensee developed the ISI plan in accordance with the requirements of 10 CFR 50.55(a) and the 1989 Edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, Subsections IWA, IWB, IWC, IWD, and IWF, for Inspection Program B. Accordingly, the inspection plan provided the necessary details of planned ISI for Code Class 1, 2, and 3 pressure retaining components and supports. The inspection interval is divided into three periods. This is the first period of the third inspection interval.

   The ten-year interval ISI plan was accepted by the NRC by a letter dated March 20, 1997, from P. D. Milano of the NRC to E. T. Boulette of the licensee. The relief requests, as appropriate, were properly documented and approved. The relief requests, PRR-7 and PRR-18, were not required, and PRRs 1, 2, and 13 were withdrawn. The inspector verified that the approvals of PRR by the NRC, and the withdrawals of PRRs by the licensee were properly documented in the ISI plan. At the time of Pilgrim Station's construction, ASME Code only covered nuclear vessel and piping up to and including the first isolation or check valve. Therefore, piping and valves at Pilgrim were designed and built to the requirements of USAS B31.1.0-1967; thus, there are no ASME Section III, Class 1, 2, or 3 systems at the plant. The components subject to ISI are depicted on the ISI boundary drawings, and included in the plan; and the augmented examinations are documented in the Quality Control Instruction No. 20-48, "Control of Augmented Examination." The inspector did not have any questions regarding the Pilgrim ISI program plan.

2. The review of the qualification/certification of the personnel engaged in the NDE of the ISI program indicated that the inspectors were properly qualified by formal and practical training, and were certified to proper levels of inspection/examination responsibility in different examination methods; e.g., Visual examination (VT), Liquid Penetrant (PT), Magnetic Particle (MT), or Ultrasonic Examination (UT). The licensee has engaged General Electric (GE) for providing all the remote vessel internal examination, and GE is also providing almost all working level NDE inspectors for the outage ISI work.

3. The inspector observed the mockup of the automatic UT machine in the GE lab. This machine was used in the UT examination of the safe-end welds in the reactor. The inspector also reviewed the video record of the steam dryer leveling screw (Remote VT). This examination was performed by a miniature, remotely operated TV camera. The inspector noted that the video images were of very high quality

with sufficient definition to disclose any defect discernible by VT examination. The core spray piping weld inside the reactor vessel was also examined by remote submerged UT equipment, GE CSI-2000, used by GE at the site. The inspector reviewed the EPRI-BWR Vessel Internals Project memorandum evaluating the use of this equipment.

The inspector also witnessed manual MT examinations of the weld, Nos. 1303 and 1304, on the main steam line inside the drywell performed by a Level II MT inspector. The examination was satisfactory, and the NDE inspector was knowledgeable in MT techniques. The inspector determined that remote VT of leveling screws, remote UT of core spray piping, and manual MT of weld were acceptable.

The inspector reviewed the licensee's snubber testing program. The requirements are set forth in the TS, Section 3.6.I/4.6.I of the plant TS. The licensee's procedures provide instructions for snubber examination and testing. Procedure No. 3.M.4-63, "Functional Testing of Mechanical Snubbers," provides instructions for functional testing of PSA-mechanical snubbers; Procedure No. 3.M.4-37, for hydraulic snubbers; and Procedure No. 3.M.4-28, for the visual examination and service life verification of safety-related snubbers. The inspector reviewed the procedures and some completed examinations. The inspector had no concerns in this area.

4. Inspection of jet pump swing gates during RFO11 revealed that several swing gates latch pins were not fully engaged and some restrainer bracket set screws were not in contact with the jet pump mixer. General Electric performed major jet pump work at PNPS approximately 10 years ago. The swing gates provide mid support to the jet pump assembly. Two swing gates were replaced but additional lead time was needed to procure additional material. BECo safety evaluation (SE) 3084, based on extensive analyses, concluded that the jet pumps remained operable with the non-conforming conditions. The inspector noted that SE 3084 did not provide the final corrective actions planned for the identified nonconforming conditions. No specific vendor or NRC generic guidance existed that provided guidance on this in-vessel issue. NRC Region I initiated a task interface agreement to NRC headquarters to review the longer term aspects of this issue and potential generic applicability. The BECo long term corrective action remain as an inspector follow item (**IFI 97-02-03**).

c. Conclusions

Based on the above observation, review of documentation, and discussion with personnel responsible for ISI program implementation, the inspector concluded that the licensee's ISI program plan, with relief requests, is approved by the NRC, and is satisfactorily maintained in an updated condition. The NDE personnel are properly qualified/certified, and inspections/examinations are adequately performed and documented. Jet pump nonconforming issues did not affect immediate operability but the final corrective actions were not planned and remain as IFI 97-02-03.

E8.2 (Update) URI 94-26-01: Diesel Generator Turbo Assist Solenoid Valve Testing

a. Inspection Scope (92903)

The inspector reviewed the status of BECo's actions to address the high failure rate of the diesel generator turbo assist solenoid valves.

b. Observations, Findings, and Conclusions

On January 24, 1994, the "B" emergency diesel generator (EDG) failed to start within the maximum allowable time due to simultaneous failure of the two turbo assist solenoid valves. Corrective action consisted of a system modification to allow on-line testing and replacement of these valves, along with an increased test frequency. However, the inspector questioned the adequacy of these actions after additional single-valve failures continued to be identified. As a result, the licensee initiated a problem report, PR 96.9413, to examine the issue further. Since the cause of failure was previously identified to be moisture in the air start system, the corrective action strategy shifted to replacing the valves with a design that is compatible with this environment. Systems engineering has recommended use of a valve that is similar in design to the air start solenoid valves, which have proven to be reliable. Pending review of this modification package, or other final corrective action, this item remains open.

IV. PLANT SUPPORT

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 External Exposure Control

a. Inspection Scope (83750)

The inspector made tours of the major radiological work areas during the 1997 refueling outage and observed work in progress, observed postings and control over work areas, and made independent radiation surveys in areas for comparison with licensee surveys and for the evaluation of shielding. In addition, the inspector reviewed licensee surveys and exposure documentation records and conducted interviews with licensee personnel.

b. Observations and Findings

The licensee established satellite RP control points to provide focused control over station areas.

The refueling floor RP control point was established in a clean area located on the refueling floor. During previous outages, this control point was established one elevation below the refueling floor due to dose rate considerations. For this refueling outage, a cylindrical concrete shield was installed around the reactor vessel head while stationed on the refueling floor, which provided a 0.5 mR/hr background area for the RP control point. Also new this outage, the licensee had built and manned a refueling floor observation room located high above the refueling floor. This observation room was manned by operations and outage management personnel and served to coordinate the refueling floor outage activities. Although this room exhibited a 1.5 mR/hr dose rate and was manned for extended periods of time resulting in additional refueling exposure, the coordination of work crews and additional work supervision oversight resulted in improved refueling floor critical path performance and reduced overall exposures for this area.

The Torus was the focus of considerable work activity during this outage. In order to address the NRC issue of ECCS strainer plugging, the licensee had designed, fabricated and was installing new ECCS strainers in the Torus. To reduce dose rates, the licensee conducted an underwater desludging operation utilizing divers. The inspector reviewed licensee's surveys of the underwater Torus work areas to determine if adequate survey detail of the diver's work area had been performed. Initial surveys were performed at the base of the Torus external shell and licensee calculations determined approximately 1 R/hr sludge deposits would be encountered by the divers. In addition, inside Torus surveys were conducted covering approximately one-half of the underwater area at regular intervals. During diving operations, the diver carried a radiation probe that provided continuous readout at the Torus RP control point. The licensee provided extremity dosimetry and whole body dosimetry for each dive. The licensee indicated that the dosimetry readings corroborated the survey information. The inspector also reviewed the safety aspects of underwater diving and determined that appropriate designated dive tenders and dressed-out backup divers were included for each dive. The inspector observed that a backup air supply was available in the event of loss of station air compressor supply. Due to radioactive piping systems external to the Torus, the dose rates to the Torus remained relatively high (10-20 mR/hr). The licensee indicated that the external radiation sources were too extensive to shield. Due to the high man-hours involved in the Torus modifications, the project was estimated to cost over 100 person-rem.

The drywell was a focus of considerable attention during this outage. During a September 1996 maintenance outage, the drywell dose rates were found to be approximately four times normal expected levels. In order to mitigate the effects of the high dose rates on the Spring 1997 refueling outage, the licensee decided to implement depleted zinc-oxide injection in December 1996 and perform a recirculation system chemical decontamination at the beginning of the refueling outage. In addition, a significant amount of drywell work was deferred until the following refueling outage (e.g., ISI). The inspector made a comparison of general area dose rates for the two principal work elevations in the drywell.

	Sept 1996 Outage[2]	Spring 1997 Outage	Spring 1995 Outage
Drywell entry	200 mR/hr	50 mR/hr	25 mR/hr
1st level up	300 mR/hr	35,65/400 (Recirc suction)	40 mR/hr

As indicated by the comparisons, the work area dose rates were effectively reduced in most drywell work areas, however, due to the limited success of the chemical

[2]The drywell was not shielded during the September 1996 outage. Both the 1995 and 1997 refueling outage drywell dose rate values include benefits due to shielding.

decontamination, dose rates were elevated compared to the previous Pilgrim refueling outage.

The drywell was posted and controlled as a locked high radiation area, with time keeping performed by control point RP personnel. A drywell "rover" RP technician was available inside the drywell at all times to oversee work activities. During this outage, increased use of closed-circuit television surveillance was provided of various work areas at the drywell control point. The inspector observed good use of the remote surveillance by control point personnel to assist the rover in conducting effective work coverage. The inspector observed generally effective radiological briefings to workers, however, due to the background noise levels and lack of space, the briefings were not always heard by all members of a work crew greater than two. The inspector observed very limited radiological postings in the drywell in spite of large dose rate gradients of 30-800 mR/hr. The inspector observed many areas of the drywell with missing floor grating and in all cases, they were marked with safety tape warning boundaries. In one large area of the 41-foot elevation on the B-loop side, grating was missing and the area was posted with safety tape, however, it was the only passageway through the area and workers were observed passing through this area. After this unacceptable personnel safety situation was reported to the licensee, prompt action was taken by installing planking over the area. It should be noted that missing drywell grating conditions were also reported by the NRC during the previous refueling outage.

c. Conclusions

The refueling floor activities were provided with increased oversight from previous outages through relocating the RP control point onto the refueling floor and with the installation of an operations supervision observation office that was manned during the outage.

The Torus diving operations were conducted with appropriate safety precautions with appropriate dosimetry monitoring and adequate surveys conducted. Due to the high dose rate gradient in water, detailed surveying techniques were warranted and improved approaches were discussed with licensee personnel.

The drywell was an area of significant radiological challenge during this outage. A chemical decontamination of the recirculation piping system was successful, but resulted in limited success. RP controls were effective in providing a roving RP technician at all times and through the use of closed-circuit television surveillance of principal work areas. Radiological briefings were well presented, however, the drywell control point environment was not conducive for briefings to work crews greater than two individuals. The inspector observed very few radiological informational postings in the drywell and, due to large dose rate variations, and limited effectiveness of radiological briefings, the inspector determined that drywell postings were weak. Removed floor grating continued to be a personnel safety issue in the drywell and required correction during this outage as it was during the previous refueling outage.

In general, the RP control points were well staffed and functioned very well in providing the radiological protection requirements of the workers. Some drywell posting and industrial safety concerns were noted and corrected by the licensee.

R1.2 Internal Exposure Control

a. Inspection Scope (83750)

The inspector reviewed all air sample results for the first 26 days of the outage, applicable air sample-based internal exposure tracking results, bioassay measurement results, and final internal exposure assessment reports. The inspector also interviewed cognizant licensee personnel.

b. Observations and Findings

The inspector determined that approximately 37 air samples were taken per day during the outage. Generally, air samples indicated less than 20 DAC (derived air concentration). The exceptions involved machining of a valve and turbine grit blasting activities. The air sample results were properly screened for high activity, and all air samples indicating $\geq$4 DAC were investigated with assigned DAC-hour tracking provided for the applicable workers. Most of the high air sample activity represented work where respiratory protection was assigned. There were two cases where workers were calculated to have received $\geq$4 DAC-hours; once during initial cutting of the LPCI loop selection logic sensing lines for chemical decontamination injection, and once during the rewelding of the same lines following chemical decontamination activities. Initial internal exposure tracking indicated 3 workers had received 4.3 DAC-hours and two workers had received 5.9 DAC-hours. The licensee conducted followup whole body counting bioassay measurements that indicated 4 of these workers had not received any measurable internal exposure. The other worker was counted on March 5, 1997 with an initial positive measurement, and was subsequently surveyed when a hot particle was found on the individual, however, a final bioassay measurement was not performed. According to calculations, there was a potential of 61 mrem internal exposure to be resolved that had not been appropriately dispositioned at the time of this inspection.

c. Conclusions

The inspector determined that effective air sampling was provided in the work areas, and that proper procedures were followed in determining internal exposures. The licensee was very effective in controlling contamination and limiting internal exposures through the use of respiratory protection. During the first 26 days of the refueling outage, only five individuals had initial DAC-hour tracking. Appropriate followup bioassay measurements had been performed with the exception of one worker that had not been completely dispositioned at the time of this inspection.

R1.3 As Low As Is Reasonably Achievable (ALARA)

a. Inspection Scope (83750)

The inspector reviewed the licensee's collective radiation exposure status and dose reduction results for the February-March 1997 refueling outage. This review included independent radiation surveys, review of licensee documents, and interviews with the RP staff.

b. Observations and Findings

As mentioned in Section R1.1 above, the licensee conducted a chemical decontamination of the recirculation piping system during the initial period of the refueling outage in order to reduce the high radiation fields in the drywell. This effort was partially successful. Interference precluded the installation of the "A" loop recirculation suction nozzle plug and prevented decontamination of the "A" recirculation suction piping. In addition, due to a lack of flow throttling capability on the vendor's decontamination equipment (a single loop decontamination was not anticipated), the "B" recirculation nozzle plugs (discharge and suction) became unseated resulting in excessive reactor water inleakage and termination of the chemical decontamination after only one cycle of nitric permanganate and oxalic acid washes had been completed (four cycles had been planned). Results were mixed. Very effective decontamination factors were achieved in some areas with reduction factors ranging from 10-55. The recirculation discharge risers achieved very good dose rate reductions for both recirculation loops. The B-loop recirculation discharge ringheader dose rates increased by 40% and both A & B loop recirculation suction piping increased by more than double from the pre-chemical decontamination dose rates. The effective chemical decontamination in some areas combined with doubling of dose rates in other areas, resulted in large variations in drywell dose rates. The licensee also provided a good shielding effort to further reduce some of the higher drywell dose rate areas.

A comparison of refueling outage dose estimates versus actual doses with 2/3 of the outage completed is provided below.

Original Outage Dose Estimate (1/23/97)	Actual Doses Obtained 26 days of 39 days
Outside Drywell 225.5 person-rem 3.0 chem decon cost	238.9 person-rem (15.7 emergent work) 2.7 chem decon cost
Drywell 117.2 (with scope reduction) 17.0 chem decon cost	79.4 (with 19.2 emergent work) 40.0 chem decon cost
Drywell Total 134.2	119.4
Planned Work 362.7 (contingency 76.2)	326.1 34.9 emergent
OUTAGE TOTAL 439 person-rem	361.0 person-rem

With the outage approximately 2/3 complete, the drywell work scope appears to be on track, with significant additional dose costs for chemical decon 40 person-rem versus 18.5 person-rem. The licensee's original estimate of 20 person-rem for chemical decontamination increased to over 40 person-rem. This was due to oversight in the need for scaffolding to reach the LPCI loop selection logic sensing lines and increased dose rates after the recirculation system was drained. The refueling activity doses also appear to be tracking as estimated. Outside drywell work projects to be approximately 50% over the estimate, with a projected outage exposure of approximately 520 person-rem, which is comparable to the licensee's revised outage goal of 510 person-rem. The licensee initially estimated the high pressure turbine overhaul to cost 35.6 person-rem with much lower dose rates than expected, this work has cost approximately 1.7 person-rem. Original licensee estimates for the torus desludging and ECCS suction strainer modification was 17 person-rem. More detailed man-hour estimating redefined the estimate to approximately 100 person-rem.

c. Conclusions

Chemical decontamination of the recirculation piping system effectively mitigated the four-fold increase in drywell dose rates experienced this outage, however, due to an unforeseen interference and vendor equipment limitation, the decontamination effects were limited, with drywell dose rates remaining generally higher than previous refueling outage values.

R2 Status of RP&C Facilities and Equipment

a. Inspection Scope (83750)

The inspector toured the station and discussed several facility modifications with licensee personnel.

b. Observations and Findings

During this inspection, the inspector conducted numerous tours of the plant during outage conditions and noted that all required radiological postings and locked areas met regulatory requirements. No deficiencies were noted in this area.

In preparation for the outage several notable facility changes have occurred that affect the RP program. Previously, the control room annex was a non-RCA area located inside the RCA. Currently, the requirement for work control signoffs has been moved out of the control room and is now performed on the second floor of the new administration building. A new passageway was constructed that connects the control room annex with the second floor of the new administration building, which allows personnel access to the control room annex without entering and exiting through the RCA. In January 1997, the principal access point for the RCA, the "red line," had been completely reconfigured and greatly enlarged in order to enhance the flow of personnel through the principal RCA boundary. An area several times larger has been added with new personnel contamination monitors and easier access to RP staff behind a large counter area. Also in January 1997, the contaminated tool depot was enlarged to several times its original size, with a commensurate increase in tool inventory. Contaminated tools may be returned to the same facility, which now incorporates a tool decontamination and monitoring area.

During this outage, the inspector observed the above enhanced facilities working very well, with excellent throughput of workers. Also the new "red line" added a satellite dosimetry office to allow resolving dosimetry concerns without leaving the RCA access control point. Very good accessibility to RP staff was observed and the RCA tool depot appeared to be well stocked and serviced the workers needs effectively.

c. Conclusions

Facility modifications involving RCA access and RCA tool control were recently streamlined and greatly enlarged. These modifications effectively increased the worker's interface with RP personnel provided an increased supply of RCA tools to meet the worker's needs. These were excellent improvements to the RCA access control program.

R6 RP&C Organization and Administration

a. Inspection Scope (83750)

The radiation protection organization was reviewed for outage staffing levels based on documentation review and on observations in the principal work areas during the performance of outage work activities.

b. Observations and Findings

The licensee expanded the RP organization to include 83 contractor RP technicians and 7 RP personnel on loan from other nuclear power plants. Including the 25 permanent station RP technicians, there were approximately 120 RP technicians servicing the refueling outage needs. Eight permanent station RP supervisors provided responsibility for major plant areas with 12 lead technicians tasked with lead responsibilities at specific RP control points. The satellite control points included: RCA access point (the red line), condenser bay, turbine deck, reactor building, drywell, torus, and the refueling floor. The inspector reviewed ongoing work activities through most of these locations and observed no shortages of RP coverage during the inspection period.

c. Conclusions

The licensee applied effective RP personnel resources for the refueling outage.

R7 Quality Assurance in RP&C Activities

a. Inspection Scope (83750)

The inspector reviewed the licensee's Radiological Problem Reports for two months of 1997 since major process changes were made to the Problem Report program in January 1997. This was based on a review of licensee documentation and interviews with cognizant licensee personnel.

b. Observations and Findings

The inspector observed that the number of Problem Reports written has increased since January. During 1996 approximately 1300 reports were documented and for the first two months of 1997 approximately 1300 reports have already been written. The inspector's screening of these latest reports indicates that there are not more problems occurring, but that the threshold for recording discrepancies or recommendations has been lowered. The inspector noted only three radiological problem reports that appeared to be of safety consequence during the January through early March 1997 time frame. Each of the three problem reports was being reviewed be a team of individuals tasked with recommending corrective actions addressing each of the identified causes. The approach appeared to be thorough, however, all three problem reports were still open and in various states of review at the time of this inspection and an assessment of results could not be made at the present time.

c. Conclusions

The licensee's corrective action program was revised in January 1997 and since that time the recording of radiological occurrences has resulted in an approximate six-fold increase. The threshold for reporting has been lowered with very few radiological events of safety consequence having been reported. It is currently too early to assess the results of the newly revised Problem Report process on correcting radiological occurrences.

P1 Conduct of EP Activities

P1.1 Emergency Plan Implementation During Unusual Event

a. Inspection Scope (71750)

BECo declared an UE on April 1 due to the complete loss of offsite power. The details of this event are discussed in Section I.O1.3 of this report. The inspector observed emergency plan actions performed in the control room during the event and reviewed BECo's "Review of events pertaining to UE #97-01, Loss of Offsite Power" report issued April 7, 1997.

b. Observations and Findings

During the UE, the inspector observed transmission and clear communication of followup notifications of the event and related information to the state and local officials from NWE's office in the control room. The inspector observed the notifications did not detract from operator communication during the event. The emergency director remained in the control room and fully aware of plant and equipment status throughout the event.

The assessment of the emergency organization's performance during the UE was performed in accordance with Emergency Preparedness Implementing Procedure EP-IP-520, Recovery. The report described the event, identified strengths, difficulties encountered, and recommended corrective actions. The report was accurate and identified appropriate areas for improvement with associated action items. No significant problems were identified.

c. Conclusions

The emergency plan was implemented as required during the Unusual Event on April 1, 1997. After the event, an accurate event report was written that reviewed the organization's response and identified any problems encountered. Appropriate corrective actions were identified and tracked to resolve the minor difficulties encountered.

P2 Status of EP Facilities, Equipment, and Resources

P2.1 Criticality Accident Requirements

a. Inspection Scope (71750)

The inspector reviewed BECo's compliance with 10 CFR 70.24, "Criticality accident requirements." The inspection included interviews with licensing and engineering personnel; and review of the Updated Final Safety Analysis Report (UFSAR), station procedures, related docketed correspondence between BECo and the NRC, and Regulatory Guide (RG) 8.12, "Criticality Accident Alarm Systems," Revisions 1 and 2.

b. Observations and Findings

In the summer of 1996, the office of Nuclear Reactor Regulation (NRR) requested information from licensees regarding their compliance with 10 CFR 70.24. Since PNPS was licensed prior to December 6, 1974, BECo was subject to sections a(2) and a(3) of the rule. Section a(2) specifies preset alarm setpoint limits for the monitoring devices in addition to maximum distance from the special nuclear material subject to a criticality accident. Specifically, a(2) requires, "The monitoring devices shall have a preset alarm point of not less than 5 millirem per hour ...nor more than 20 millirem per hour." Section a(3) specifies, in part, "The licensee shall maintain emergency procedures for each area in which this licensed special nuclear material is handled, used, or stored ... These procedures must include the conduct of drills..."

Prior to operation, BECo was exempted from 10 CFR 70.24 under its Materials License SNM-1193. On December 6, 1974, BECo requested the exemption be transferred to their Operating License DPR-35. By letter dated January 8, 1975, the NRC denied the request. Following this denial, on April 1, 1975, BECo requested an exemption from Section a(3). The NRC denied this request by letter dated June 30, 1975. Therefore, BECo was subject to the requirements of 70.24 since the expiration of Materials License SNM-1193.

Through many discussions with BECo personnel and review of related documentation, the inspector discovered that BECo has gamma radiation-detecting area radiation monitors (ARMs) located on the refuel floor and in the new fuel storage vault, as required by the rule. These monitors are listed in UFSAR Section 7.13, Area Radiation Monitoring System. The ARMs which are potentially relevant to this rule are 1) new fuel storage area, 2) new fuel vault, 3) refuel floor shield plug area, 4) spent fuel pool area. All but the new fuel vault ARM are located on the refuel floor. The new fuel vault ARM is located inside the vault and can be accessed by removal of floor plugs on the refuel floor. All ARMs are calibrated using procedure 6.5-160, Calibration of the Area Radiation Monitoring System. The inspector verified that the new fuel storage area, shield plug area, and spent fuel pool area ARMs were calibrated semiannually. However, review of the calibration procedure and copies of the as-left settings on these monitors revealed that the alarm setpoints are 40 mR/hr and 100 mR/hr, contrary to the requirements of the rule.

The new fuel vault monitor has not been calibrated at least since 1990 due to the fact that the new fuel vault was not used to store new fuel. The inspector verified that procedure 4.2, Inspection and Channeling of Nuclear Fuel, contains a prerequisite which requires the new fuel vault area radiation monitor calibration to be performed prior to storing new fuel in the vault. Since then, as observed by the inspector this outage, new fuel has been stored in the spent fuel pool after it is removed from its shipping container on the refuel floor and inspected. In other recent outages new fuel has been stored in the spent fuel pool after inspection and the new fuel vault has not been used. During the review of procedure 6.5-160, the inspector determined that although the intent was to calibrate this detector only when needed, both a note in Section 8.0 of the procedure and a note on Attachment 1, ARM Summary, either allude to special requirements or state that the new fuel storage area detector must be calibrated if the vault is to be used. Both notes were intended to focus on the fuel vault detector. After the inspector questioned these notes, BECo initiated a nomenclature change to clarify the procedure and nameplate on the detectors to correct these oversights. The inspector verified that the detectors were calibrated as intended. The inspector determined that the ARM alarm setpoints do not meet the requirements of 10 CFR 70.24(a)(2).

BECo reviewed the history of criticality accident drills and determined that although procedures 5.1.3.5 and later 5.8.1 existed, no such drills have been conducted since 1979. In 1980, Quality Assurance Audit 80-16 issued deficiency report (DR) 646 for the failure to conduct refueling floor drills. This DR was inappropriately closed in June 1981, based on the fact that procedure 5.1.3.5, which had referenced 70.24, was retired and superseded by procedure 5.8.1, which did not specifically require a refuel floor drill. BECo currently has no procedure for criticality evacuation drills, which is also a violation of the rule.

c. Conclusions

The existing configuration of radiation monitors on the refuel floor does not satisfy the requirements of 10 CFR 70.24, "Criticality accident requirements." In addition, BECo has not conducted evacuation drills as required by this part. BECo committed to come into compliance with the regulation or receive an exemption prior to receiving, handling, or storing any new fuel. This problem has minimal safety consequences. The NRC is currently reviewing the problem in light of its Enforcement Policy. Accordingly, this area is unresolved (97-02-04) pending further NRC staff review.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Fire Protection Assessment of Main Transformer Failure

a. Inspection Scope (71750)

On March 7 1997, PNPS was shut down and in a refueling outage when it experienced a main transformer fault as described in Section I.O1.2. This fault caused one of the phase bushings/insulators to fail. Upon its failure, approximately 5,400 gallons of mineral oil contained in the upper transformer housing leaked out of the bushings and into the bus duct. The inspector discussed the event with BECo personnel, toured the plant areas affected by the transformer failure and resulting oil spill, and assessed the adequacy of the existing plant fire protection features and fire enhancements proposed by BECo against a postulated fire using the event conditions.

b. Observations & Findings

Of the 5,400 gallons of oil which leaked from the transformer bushing, 4,300 gallons flowed through the bus duct and into the turbine building via the bus duct air cooler. The oil leaked out of the air cooler through the air intake opening and onto the turbine building floor. The oil covered the turbine building floor (Elevation 23'- 0") bounded by column lines A-15 to A-20 and C.2-15 to C.2-20. Since PNPS is a BWR, the turbine building is divided by a concrete biological shield wall. This wall separates the low and high pressure turbine and its condenser from the generator end of the turbine/generator assembly. This wall also formed the oil spill boundary along the A-15 to C.2-15 column line. The oil in the turbine building collected around the hydrogen seal oil unit, under the generator and exciter, under the generator hydrogen addition control station[3], the stator winding liquid cooling unit, the fire protection deluge valves for the transformer fire protection systems, the low pressure carbon dioxide (CO_2) storage unit (used for fire protection and generator purge) and in the equipment/truck bay. The concrete block walls (3-hour fire barrier) along column lines B-18 to C.2-18, B-18 to B-19, B-19 to C.2-19, and C.2-19 to C.2-20 separate the "B" train essential switchgear room from the turbine building. These walls acted as an oil spill boundary. Oil did however flow under the double leaf fire door in the fire barrier wall located along column line B-18 to B-19 and collected around and inside Motor Control Centers (MCCs), the exciter control panel, and the neutral ground cubicle. In addition the oil flowed down the stairs located near column line A-15. On elevation 6'-0" oil collected in the area of the radwaste monitoring tanks, the treated hold-up tanks, the corridor adjacent to these tanks and the room which contains the instrument air compressors.

During power operations, transformer faults such as that experienced at PNPS frequently result in transformer oil fires. Therefore, if this event had occurred during power operations there is a high likelihood that the oil would have ignited, resulting in a serious fire that could have presented significant challenges to the plant and certain essential functions.

POSTULATED FIRE

Based on the event conditions and the overall combustibility of the oil (mineral oil has a flash point 275°F), a postulated fire would develop in a moderate manner with dense smoke. The sprinkler protection in the turbine building would actuate to control the upper hot gas layer in the area of the generator and the hydrogen seal oil unit and the hydrogen addition station. It is possible that the fire could propagate down the stairs via burning oil and involve the radwaste holding tank area and its adjacent corridor on elevation 6'-0". Under these conditions smoke and hot gases could be transported via the open

---

[3]According to the licensee, the hydrogen line is equipped with an excess flow check valve. This valve is designed to isolate the gas flow in the line in the event it senses excessive gas flow conditions such as those created by a piping integrity failure.

equipment/truck bay to the elevations above the fire affected floor. Due to the plant configuration, smoke could fill the turbine operating floor and the turbine building roof line. Power-operated roof ventilators located near the turbine building roof's center line could be used to vent some smoke out of the building. In addition, smoke propagation into the "A" essential switchgear room is probable. Smoke can enter this room through the ventilation opening which interfaces with the equipment/truck bay on elevation 37'-0". With respect to the "B" switchgear room, it is possible foı a fire to propagate under the door. This fire could develop a hot gas layer in the upper half of this room sufficient to transfer heat to the cables in the cable trays near the ceiling. The increasing temperature of the hot gas layer could result in ignition of the cables and fire propagation along these cables in the cable trays located near the ceiling. Under such conditions, it is probable that the switchgear room could burnout.

The rolling equipment/truck fire door is normally closed. If it were opened by either fire brigade or operations personnel, burning oil could flow out of the turbine building and down the roadway leading to the equipment/truck bay.

EXISTING PLANT FIRE PROTECTION FEATURES

An automatic pre-action sprinkler system actuated by thermal fire detection devices is provided at the ceiling over the turbine building floor area which was affected by the oil spill. There was no automatic sprinkler protection provided for the adjacent equipment/truck bay. The turbine building area is separated from the "B" train essential switchgear room by a 3-hour fire-rated concrete block wall. All penetrations through these walls are provided with fire protection features such as penetration seals, doors and dampers, that have an equivalent fire resistive rating to that of the fire barrier. The structural steel inside the switchgear room is protected with fire-proofing material and area-wide smoke detection capability is provided. A CO_2 manual fire fighting hose line is located in this room and water fire fighting hose lines are located in plant areas adjacent to this room and the turbine building area of concern.

PLANT FIRE PROTECTION ENHANCEMENTS

BECo is taking an engineering approach to minimize the fire hazard impact that a future event of this type could have on the plant. In addition to the existing plant fire protection features, BECo made the following fire protection design enhancements during the outage:

1. Installed containment curbs at the fire doors leading to the "B" essential switchgear room and the stairway leading down to the liquid radwaste holding tanks. This curbing will preclude oil flow under these doors and confine the oil hazard to the Turbine building; and

2. Modified the bottom face of the three transformer iso-phase bushing boxes by installing an 8-inch diameter down-comer drain line for each box. These drain lines were routed and drained to the transformer oil leak retention pit (rock trap). Each drain line was equipped with a rupture disk designed to open under 2 pounds per square inch of static oil pressure in the drain line down-comer. The end of the drain line down-comer was capped with a screen to prevent small animal intrusion.

c. Conclusions

Based on the on-site review of the existing plant conditions and fire protection features, the inspector concluded that the fire protection enhancements should provide reasonable assurance that if this event or a similar one were to occur, the transformer oil fire hazard would be controlled and the potential fire effects on safe shutdown and safety related electrical components would be minimized. The new fire protection enhancements should provide an additional level of fire safety diversity.

F3 Fire Protection Procedures and Documentation

F3.1 Fire Hazard Analysis Review

a. Inspection Scope (71750)

After the transformer failure on March 7, the inspector reviewed BECo's Fire Hazard Analysis to determine whether an oil spill of such a magnitude had been considered in the analysis of the affected fire zones.

b. Observations and Findings

The inspector reviewed the fire hazard analysis fire zone data sheets for turbine building elevation 23' up to 51" and radwaste and control building elevation -1' up to 23'. The inspector discussed these sheets with a fire protection engineer and determined that fire loading in this area comparable to the oil spill which occurred following the transformer failure had not been considered in the fire hazard analysis.

As described in Section F2.1, BECo installed berms on the 23' elevation of the turbine building to prevent oil in this area from spreading into the "B" switchgear room and radwaste corridor area. A berm was also installed by the door leading to the cable spreading room area. In addition, drain lines were installed on the isophase bus ducts, located outside of the turbine building, to direct any future oil coming through those ducts to the rock trap surrounding the transformer. The inspector verified that the fire hazard analysis was revised to document these changes on April 11, prior to plant startup.

c. Conclusions

The fire hazard analysis did not reflect potential fire loading in the turbine building and radwaste area commensurate with the oil spill after the main transformer failure because this was not an anticipated failure mode. The enhancements to install berms in the turbine building and drain lines on the isophase duct lines will limit the fire loading effect on these areas should a similar failure occur in the future. The fire hazard analysis report was updated to reflect these changes before plant startup following RFO11.

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 May 16, 1997. The licensee acknowledged the findings presented.

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 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 82301:	Evaluation of Exercises for Power Reactors
IP 83750:	Occupational Radiation Exposure
IP 92700:	Onsite Followup of Written Reports of Non-routine Events at Power Reactor Facilities
IP 92901:	Followup - Operations
IP 92902:	Followup - Maintenance
IP 92903:	Followup - Engineering
IP 92904:	Followup - Plant Support
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors

ITEMS OPENED, CLOSED, AND UPDATED

OPENED

URI 97-02-01	Feed water system regulating valve and control rod initial movement problems impacted operational activities during start-up from RFO11.
VIO 97-02-02	Inadequate electrical design control for voltage regulating transformers and MO-1301-53 which adversely impacted safety related equipment.
IFI 97-02-03	Jet pump nonconforming conditions.
URI 97-02-04	Compliance with 70.24

CLOSED

LER 95-003	Manual Scram.
LER 97-006	Inadequate procedure caused brief loss of shutdown cooling.

UPDATED

URI 94-26-01	EDG turbo assist valve reliability.

LIST OF ACRONYMS USED

AFPC	Augmented fuel pool cooling
ALARA	As Low As Is Reasonably Achievable
APRMs	Average Power Range Monitors
BECo	Boston Edison Company
CFR	Code of Federal Regulations
EDG	Emergency Diesel Generator
ESF	Engineered Safety Feature
HPCI	High pressure coolant injection
I&C	Instrumentation and Controls
IFI	Inspection Follow-Up Item
IR	Inspection Report
ISI	Inservice Inspection
LER	Licensee Event Report
LOOP	Loss of Offsite Power
LPCI	Low pressure coolant injection
MSIV	Main steam isolation valve
MSL	Main Steal Line
NCV	Non-Cited Violation
NOV	Notice of Violation
NRC	Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
PASS	Post accident sampling system
PNPS	Pilgrim Nuclear Power Station
PR	Problem Report
QA	Quality Assurance
RBIS	Reactor building isolation system
RCA	Radiological controlled area
RCIC	Reactor core isolation cooling
RFO	Refueling outage
RHR	Residual Heat Removal
RP	Radiological Protection
SBGT	Standby Gas Treatment
SBO	Station Blackout
SRO	Senior Reactor Operator
TM	Temporary Modification
TS	Technical Specification
UE	Unusual Event
UFSAR	Updated Final Safety Analysis Report