EXECUTIVE SUMMARY

Pilgrim Inspection Report 95-21

Safety Assessment/Quality Verification: Overall, positive performance was indicated by effective operator response to intake structure system challenges, system engineer identification of equipment deficiencies at an early stage and plant management's interest in minimizing equipment deficiencies. The management decision to initiate response teams, to evaluate the significance of the October 6, 1995 intake structure east bay water level transient and also the master surveillance test program weaknesses, represent a continued emphasis on reactor safety. An opportunity for improvement was identified in the area of senior reactor operator performance during implementation and reviews associated with plant administrative programs.

Plant Operations: Strong operator performance was indicated during the implementation of the maximum extended load line limit analysis (MELLLA) modification in terms of training, operator understanding, and procedural updates. The training was provided to licensed operators at appropriate intervals and included pertinent information on the affected equipment and procedural aspects of the modification. Operator competence and proficiency in the MELLLA region of the power-to-flow map was observed during various power reductions that occurred during this period.

Overall, operators performed well during intake structure-related evolutions that included a condenser backwash to reduce the build-up of mussels and also a seaweed intrusion event. During the mussel backwash, some condensate flashing occurred in the hotwell and sea water discharge temperature increased unexpectedly. Operator monitoring of condenser temperatures and subsequent termination of the backwash averted more serious conditions. The operator response to the seaweed intrusion was good overall, especially in the adherence to a new intake structure fouling procedure, and averted a reactor scram. However, a control rod was mispositioned during the rapid downpower event. The management decision to initiate an event response team to review the seaweed intrusion event was a noted improvement in management performance when compared to the December 1993 intake structure related event.

Maintenance and Surveillance: The I&C group prestaged redundant vibration instrumentation during a standby liquid control system surveillance to be prepared for the work activity in the event of any problems. LCO maintenance outages for HPCI and RCIC were well planned and executed. Although some miscommunication was observed during the HPCI outage, overall coordination with supporting departments was good. Management provided substantial oversight of the work activities. The emergent RCIC and planned HPCI outages demonstrated plant management's commitment to minimize equipment deficiencies. Although the aforementioned maintenance work was planned and coordinated well, an inadequate plant impact assessment associated with a preventive maintenance activity on a standby gas treatment (SBGT) fan breaker resulted from human performance errors. These errors resulted in the unplanned, action of the SBGT dampers changing position.

A quality assurance audit discovered that a core spray technical specification (TS) surveillance was missed due to operator error. Specifically, a senior reactor operator did not implement the surveillance program guidance to highlight the partial completion of the related surveillance activity. During NRC review of this issue, the adequacy of a master surveillance tracking program (MSTP) technical specification related signoff in a procedure for the SBGT system was identified as a weakness. As a result of this procedure weakness and others recently encountered with TS-related surveillances, the licensee established an issue team to perform a comprehensive 100% verification of the MSTP/technical specification interface.

Engineering: A systems engineer exhibited an excellent problem identification ability during the conduct of a walkdown of the residual heat removal system. A through wall leak was identified and successfully repaired in the drain pipe coming from MO-1001-28B valve body. Elevated salt service water inlet temperatures was experienced during this inspection period by as BECO continued their efforts to revise the design and licensing basis for this system.

Plant Support: Actions taken after exceeding the annual and outage ALARA radiation dose goals were appropriate. The management actions to revise the goal, require dose extensions for work groups, and initiate ALARA action plans were positive actions to refocus plant personnel on keeping dose ALARA. Effective radiological planning and execution were observed during the replacement of the "B" spent fuel pool cooling pump. The spread of contamination was minimized by good worker practices. In addition, an appropriate ALARA dose prediction of the pump work enveloped the actual dose accumulated during the work.

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U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket No.: 50-293

Report No.: 95-21

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

Facility: Pilgrim Nuclear Power Station

Location: Plymouth, Massachusetts

Dates: August 20, 1995 - October 7, 1995

Inspectors: R. Laura, Senior Resident Inspector
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Approved By: R. Conte 11/6/95
R. Conte, Chief Date
Reactor Projects Branch 5

Scope: Resident inspector safety inspections were conducted in the areas of plant operations, maintenance and surveillance, engineering, plant support, and safety assessment and quality verification. Reactive inspections were conducted for the unplanned downpower event due to seaweed intrusion, a missed core spray technical specification surveillance test, and evaluation of elevated salt service water system (SSW) inlet temperatures. The conduct of corrective maintenance outages for HPCI and RCIC were evaluated. The revised ALARA annual dose goal was reviewed.

Findings: No violations were identified. Further NRC staff review is warranted on elevated SSW inlet temperatures (unresolved item, 50-293/95-21-01, section 4.2). A BECo identified core spray system surveillance test violation was dispositioned as a non-cited violation. A weakness was identified with a standby gas treatment system procedure that inadvertently allowed signoff of two technical specification surveillance activities when only one was performed and further NRC staff review is warranted on BECo review and corective actions (inspector follow item, 50-293/95-21-01, section 3.4). Performance during this seven week period is further summarized in the Executive Summary.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

On August 20, the Pilgrim Nuclear Power Station (PNPS) output was reduced to approximately 70 percent power to reposition control rods and adjust core flow to operate using the Maximum Extended Load Line Limit Analysis power-to-flow map. Subsequently on that same day operators returned the unit to full power.

On September 17, operators reduced power to 50% for a main condenser thermal backwash, which was not completed due to equipment problems. On September 18, power was returned to 100%. On September 23, after repair of the backwash equipment, operators again lowered power and performed the backwash. A day later on September 24, after completing the backwash, operators increased power to 100%

The unit remained at approximately 100% power until October 5 when power was again reduced to approximately 50% for a condenser backwash due to mussel fouling. On October 6, reactor power was returned to 100%.

Later that day on October 6, operators reduced reactor power to approximately 45% due to a significant amount of seaweed intrusion. Backwashes of the main condenser and closed cooling water loops were completed and on October 7, the close of this inspection period, PNPS was operating at 100 percent rated power.

2.0 PLANT OPERATIONS (71707, 92901)

2.1 Plant Operations Review

The inspector observed the safe conduct of plant operations, during regular and backshift hours, in the following areas:

Control Room	Fence Line
Reactor Building	(Protected Area)
Diesel Generator Building	Turbine Building
Switchgear Rooms	Screen House

Control room instruments were independently observed by the inspector and found to be in correlation between channels, properly functioning, and in conformance with technical specifications (TSs). Operator shift logs, limiting conditions for operation log, and night orders were routinely reviewed and found to be appropriately maintained to reflect plant conditions and communicate plant activities. Alarms received in the control room were discussed with the operators who were aware that the alarms were in and knowledgeable of their cause. Control room and shift manning were in conformance with TS requirements. Posting and control of radiation, high radiation, and contamination areas were appropriate. Workers were observed complying with radiation work permits and using the required personnel monitoring devices. Ongoing plant coating activities were properly coordinated with control room operators to ensure that they did not adversely affect plant conditions.

2.2 Maximum Extended Load Line Limit Analysis (MELLLA) Operation

Operators reduced reactor power to 70% to reposition control rods to allow for MELLLA power-to-flow map operation starting on August 20. The new area for operation on the power-to-flow map extends plant operation at rated power with less than rated core flow. This is achieved by operation with control rods withdrawn further out of the core than in the past. Full power operation with less than rated core flow improves fuel cycle efficiency and will aid PNPS in maintaining 100% power for the new two year operating cycle.

As part of this modification, the average power range monitor (APRM) flow biased setpoints for rod blocks and scrams were elevated, eliminating nuisance rod blocks which were received in the past. In addition, the recirculation pump runback associated with the Number 2 limiter was changed from 65% speed to 44% speed to ensure a sufficient power decrease during MELLLA conditions and prevent a low level scram on the loss of one feed pump.

The inspector reviewed the training provided to operators on the MELLLA modification. This training was given in three stages. The first stage, which included a brief introduction to what MELLLA meant and might look like, was given before the refueling outage and before any procedural changes were made. The second stage was given before restart from the outage and included a detailed lesson on MELLLA, the expanded power-to-flow map including the new thermal hydraulic instability regions, and the governing procedure for station power changes. The final training session reviewed the applicable station abnormal procedures that were revised due to the MELLLA installation. The inspector determined the training was given at appropriate intervals during the implementation of the modification. The training material included pertinent information for the operators regarding the overall description of the equipment (new APRM cards for the flow biased scram and rod block setpoint changes) and procedural (revised procedures and power-to-flow map) aspects of the modification.

The inspector verified selected procedure updates and discussed the changes with operators. The operators were familiar with the procedure changes and with the effect of the plant modifications. Also, with the various reductions in power this period, the inspector observed proficient use of the revised procedures and power-to-flow map in the control room as evidenced by plotted planned power reduction path and actual placement on the map as the evolutions progressed. In addition, whenever the caution zone of the power-to-flow map was approached and/or entered, additional operator awareness was observed.

2.3 Condenser Backwash Due to Mussel Fouling

Subsequent to the backwash performed on September 23, 1995, operators noticed an increase in condenser hotwell temperatures prompting the operators to reduce reactor power during low tide to lower hotwell temperatures. Another backwash was performed on October 5 to purge the condenser tubes of accumulated mussels and restore hotwell temperatures to normal levels. A normal backwash is sometimes required some weeks after a thermal backwash. During the thermal backwash, the mussels and the material they produce to attach themselves to the pipe walls are weakened. At times this material will break down all at once and only the thermal backwash will be needed. However, other instances have occurred, as in this case, where the material breaks down later and the pipes require a normal backwash to flush the mussels. Prior to commencing the normal backwash, completion of maintenance on the "C" intake traveling screen was required and the backwash was performed at low tide conditions. During the evolution, the operators noted degrading condenser vacuum and commenced further power reduction with control rods and recirculation flow. When condenser vacuum degradation progressed, the operators secured the backwash. The "A" seawater loop was returned to normal service and condenser vacuum was restored. After stabilization, backwashes were performed multiple times through each loop to flush the mussels.

The inspector observed the power reduction and portions of the backwash. Good operator performance of the power reduction and full operator cognizance of operation in the caution zone of the power-to-flow map were noted. Operators appropriately monitored the condenser temperatures and vacuum. Some flashing was experienced in the hotwell. No damage was detected as a result of the hotwell flashing and more serious conditions were averted by the operators' early termination of the backwash. Overall, the inspector observed strong operator performance during the evolution as evidenced by operator monitoring of appropriate indications and early termination of the backwash.

2.4 Condenser Backwash due to Seaweed Intrusion

During the afternoon of October 6, the control room received periodic alarms for increased differential pressures across the intake traveling screens due to seaweed intrusion. The operators were operating screens, two at a time, in an effort to clear the alarms. However, about the time of low tide, a sudden and unexpected insurge of seaweed occurred which affected the east seawell intake level. As a result of the subsequent degradation of level in the bay, the operators performed a rapid power reduction and secured the "A" seawater pump. Backwashes of the affected side of the condenser tubes and reactor building closed cooling water (RBCCW) and turbine building closed cooling water (TBCCW) heat exchangers were performed. On the morning of October 7, the operators returned the plant to 100% power.

The inspector responded to the control room and observed operator actions during the transient. Overall, strong operator performance was noted with effective command-and-control. While observing the event and later during review of plant computer traces and procedures, the inspector noted good use of operations procedures, notably one specifically written in response to a December 1993 fouling event (documented in NRC Inspection Report 93-23), 2.4.154, "Intake Structure Fouling". The operators were recently trained on the procedure and successfully followed it, thereby averting a reactor scram associated with low condenser vacuum. A more effective response was demonstrated during this event as compared to the December 1993 event as evidenced by east seawell level drops of 11.5 and 18 feet, respectively.

Although overall use of procedures was good, a control rod was mispositioned during the rapid downpower. The subsequent routine operator verification of rod positions identified this problem. The rod mispositioning had no adverse effect on the reactor and appropriate corrective actions were taken upon discovery to return the rod to its correct position in a timely manner.

During the event, a TS operational thermal limit for Minimum Critical Power Ratio (MCPR) (2.37), as a ratio of the operational MCPR limit and the actual MCPR, was exceeded for four rods. Again, operator review discovered this condition, the appropriate limiting condition for operation (LCO) was entered, and actions were taken to exit the LCO within less than half of the allowed time. The inspector noted that at no time was the thermal safety limit for MCPR (1.07) exceeded. Only the operational limit was affected when core power was reduced below 45% and the new limit was calculated. During a deep back shift inspection, the inspector attended the licensee's event critique. Appropriate operations management personnel, operators, and systems engineering personnel were present. The licensee's initial review of the event was thorough and the immediate corrective actions were reasonable. In addition, longer term corrective actions and a comparison of this event with the December 1993 intake fouling event were under evaluation.

During the event, the inspector noted effective command-and-control by the senior reactor operators and good communication between the control room and local operators despite some weaknesses in the page system which made communication difficult. As mentioned above, although there was a rod mispositioning, procedures were followed well and appropriate actions were taken by plant personnel in response to the seaweed intrusion. Operators effectively placed the plant in a safe condition to mitigate the consequences of a decreasing intake structure water level.

The event critique addressed the sequence of events, operator performance, and immediate corrective actions. Boston Edison Company (BECo) initiated problem reports (PRs) to look at: (1) the rod mispositioning, (2) exceeding an operational thermal limit, and (3) the overall response to the event. The inspector considered the plant management decision to initiate an event response team to independently review this event noteworthy. In contrast to the December 1993 intake structure fouling event, BECo management initiation of an event team for this event demonstrated strong management interest.

3.0 MAINTENANCE AND SURVEILLANCE (62703, 61726, 92902)

3.1 Routine Maintenance and Surveillance Observations

The inspector observed portions of selected surveillance and maintenance activities to verify proper calibration of test instrumentation, use of approved procedures, performance of work by qualified personnel, conformance to LCOs, and to verify correct system restoration following maintenance and/or testing.

The inspector observed reactor operators and instrumentation and controls (I&C) technicians perform portions of procedure 8.4.1, Standby Liquid Control (SLC) Pump Quarterly Capacity and Flow Rate Test. The inspector reviewed this quarterly surveillance procedure verifying that the requirements of TS Section 4.4.A.1 to prove SLC loop operability were met. The inspector observed good coordination and communication among the operators conducting the test, the control room operators, the I&C technicians and the system engineer who also observed the testing. The operators correctly followed the procedure using effective self-checking techniques. I&C personnel prestaged redundant methods for gathering vibration information since one of the instruments exhibited problems during a surveillance earlier in the week. When vibration readings were exceptionally high, the technicians used the other vibration instrument. Both trains of SLC passed the surveillance with no discrepancies noted. In summary, operators and I&C technicians performed the surveillance well and I&C personnel were proactive in prestaging redundant vibration instrumentation.

The inspector observed the performance of surveillance procedure 8.5.4.6, High Pressure Coolant Injection (HPCI) Pump and Valve Operability From the Alternate Shutdown Panel. The surveillance proved operability of all HPCI equipment operated from the alternate shutdown panel. This yearly surveillance test satisfied the applicable requirements of TS 4.12.5 for plant alternate shutdown panel operability. The inspector noted the results of the surveillance were acceptable. A detailed brief was conducted by the nuclear operating supervisor (NOS) prior to the performance of the surveillance. In addition, good procedure adherence, communications, and self-checking were displayed by operators performing the test.

3.2 LCO Maintenance Outages

3.2.1 High Pressure Coolant Injection (HPCI) System Maintenance Outage

The inspector reviewed the maintenance planning, conduct of repair activities, and retests for the planned HPCI system on-line LCO-maintenance activities. The HPCI system was removed from service on August 29, 1995, to replace General Electric SBM control switches and to inspect the gland seal condenser blower.

In accordance with PNPS Procedure 1.2.2, Administrative Ops Requirements, the licensee developed a cohesive plan prior to performing the LCO planned maintenance. Job walkdowns, hands-on parts verification, adequate manpower resources, identification of contingency plans, and notification of supporting departments were verified complete prior to commencing the maintenance. The planning schedule indicated that the maintenance activities would take approximately two and one-half days, of the allowed fourteen day TS outage time, once the system was released for work. The maintenance activities were performed around-the-clock to minimize the time in the TS LCO action statement. Continued supervisory oversight and engineering support were provided for the duration of the work activities. The inspector verified proper conduct of repair activities and post-work testing in accordance with the maintenance work plan.

Although the work activities were completed within the projected schedule, there were a few minor delays due to an inadequate pre-job brief and miscommunication between maintenance and quality assurance personnel. Although documented in the work package for the HPCI gland seal condenser blower, the pre-job brief did not include that due to plant conditions, the heater on the blower motor could not be isolated and therefore the motor leads would need to be lifted live. Miscommunication between maintenance and quality assurance personnel on when to resume the HPCI blower disassembly after a morning break resulted in a delay in resuming work. Also, maintenance planning did not include appropriate ALARA considerations in that the contamination boundary was not established around the gland seal condenser blower prior to releasing the work activities.

During the disassembly of the HPCI gland seal condenser blower, the licensee identified that only two of the three blower impellers were installed. PR 95.9464 was initiated to evaluate this condition and the root cause of the occurrence. The licensee's subsequent operability evaluation concluded that this condition did not render the HPCI system inoperable. The condenser blower is designed to maintain the HPCI turbine gland seal condenser at a negative ten inches of water. Although the blower's efficiency was reduced, minimal gland seal leakage was observed during HPCI runs. The last time the blower was disassembled was in 1989; no abnormal operation of the system had been noted since that time. A new three impeller package was installed and tested satisfactorily.

The SBM control switches were replaced to improve component reliability as PNPS and industry experience has indicated that SBM control switches with cam followers made of Lexan are susceptible to through wall cracks which may result in the failure of the control switches. (This issue was documented in NRC Inspection Report 95-14.) BECo staff developed a program to tentatively replace all SBM safety related switches with Lexan cam followers by December 1995. The inspector observed portions of the SBM switch replacement noting good technician familiarity with the job, adherence to work plan, self-checking implementation, and quality assurance and supervisory oversight.

Overall, the inspector concluded that the HPCI LCO maintenance was well controlled, coordinated and executed in a professional manner. The maintenance outage work was pre-planned in great detail, and the status of the work activities were discussed during the morning status meeting and at the afternoon maintenance planning meeting. The activities were completed within schedule. Although there were a few minor problems with coordination between disciplines, which indicate the need for enhanced work planning, overall interface with supporting departments was good. Management oversight of the activities was noted. The licensee held lessons-learned meetings to evaluate the performance of the departments involved and identified several areas for improvement. The inspector noted open discussions of the performance weaknesses and problems encountered during the outage. Areas identified for improvement included communications and coordination, pre-staging of parts, and earlier and more complete pre-job walkdowns and briefings. Many of the lessons learned were expected to be corrected by the new work planning process which was in the initial implementation phase at the end of the inspection period.

3.2.2 Reactor Core Isolation Cooling (RCIC) Emergent LCO-Maintenance Outage

During a RCIC operability surveillance on September 5, the system engineer noted steam leakage from the gasket area of the 3-inch auxiliary boiler blank flange connection to the RCIC turbine. In addition, following the surveillance the flow controller output, which had oscillated around the setpoint tape at 400 gpm, read 60 gpm after shutdown. Due to the steam leak, the licensee decided to take the RCIC system out of service to perform LCO maintenance on the flange and flow controller.

The outage was well planned and controlled. The licensee considered expanding the work to include replacement of SBM switches, but decided to limit the work to the flow controller and flange. The SBM replacement was not task ready and the inspector considered it positive that the licensee did not try to rush preparation of the job to fit into this LCO window. Both of the selected jobs were started on the morning of September 7 and RCIC was returned to service later that day. A total of 12 hours was spent in the LCO, while the TS allowed outage time was 14 days.

The inspector discussed the leaking blank flange work with the maintenance personnel and determined that they were knowledgeable of the work scope, dressout requirements, and significance of the RCIC system and LCO time. The inspector visually examined the separation of the flanged fitting observing three indications of steam cutting on the flange. The maintenance technicians noted that the gasket did not provide maximum makeup with the flange seating area. As a result, the gasket material was changed from Flexitallic to Garlock to provide better crush and coverage of the mating surface. Maintenance and engineering personnel interfaced well and used the drawing change process to improve the system design. The new gasket was installed and the blank flange replaced, satisfactorily passing the post work test. While no further repair of the flange is required as a result of the steam cutting, BECo plans to repair the flange during the next refuel outage as part of separate work on the system.

The inspector also observed the calibration check and subsequent backfill for the flow transmitter. The I&C technicians were familiar with both procedures and performed the job well. The calibration check was done prior to the backfill to determine whether improper previous calibration was the cause of the observed flow reading with no flow. The calibration was verified to be satisfactory and the backfill was completed. Following the backfill, the flow indicator correctly read 0 gpm.

The emergent RCIC LCO maintenance outage was well planned and controlled. Technicians were knowledgeable of the work and followed the procedures and maintenance requests. The work was completed expeditiously and the inspector observed the successful post work test for both jobs. The post-work tests were appropriate to determine operability of the system. System engineer and management oversight of the work were noted. The inspector considered it positive that the system engineer identified the steam leak at the blank flange. This outage demonstrated management's interest in minimizing equipment deficiencies.

3.3 Missed Technical Specification Core Spray Surveillance

An August quality assurance (QA) audit identified the missed performance of a core spray (CS) system "B" loop valve quarterly operability test in May 1995. The test for the "A" loop was performed; however, both loops were signed off as complete in the master surveillance tracking program (MSTP). The "B" CS loop was declared operable on May 9, 1995 without the appropriate testing. A PR should have been issued to note that the test was done only for the "A" loop and a MSTP repetitive (rep) task for the "B" loop should have been created. Because this was not done, the TS 3.5.A.2 action statement for the "B" loop was not met during the interval of May 9 through June 23, 1995, when the test was satisfactorily performed. PR 95.9448 was initiated to address this issue and BECo issued Licensee Event Report 95-09 in accordance with the requirements of 10 CFR 50.73.

The inspector attended the critique for the issue and observed open discussion among the involved disciplines. Immediate corrective actions, including correcting the MSTP database and reviewing the other dual loop operations procedures that were performed during the outage to verify that there were no similar occurrences, were considered appropriate. In addition, the Technical Programs Department split out all remaining rep tasks in the MSTP for multi-loop procedures so that in the future if only one train is tested a rep task is specifically called out for the train to ensure that portion of the surveillance is performed for the other train and a PR will not be required.

The inspector reviewed this TS surveillance violation (TS 3.5.A.2) in accordance with the NRC staff enforcement policy (60 FR 34381, June 30, 1995), noted that the event was reported to the NRC, and concluded that corrective actions were implemented in a timely manner and no safety consequence resulted. It was commendable that the QA audit identified the violation. This self-identified violation was of minor significance and is dispositioned as a non-cited violation consistent with the NRC enforcement policy.

3.4 (Open) Inspector Follow Item (50-293/95-21-01): Master Surveillance Tracking Program (MSTP)/Technical Specification Correlation Inadequacy

As independent followup of the issue in Section 3.3, the inspector reviewed the PNPS's TSs for other multi-train safety systems including salt service water (SSW), reactor building closed cooling water (RBCCW), SLC, and standby gas treatment (SBGT) and selected specific TS surveillance requirements. Printouts for the selected TSs were obtained which showed the surveillance performed to meet the TSs. The inspector then reviewed the MSTP completion data for those systems for the past three years. In order to determine if any of the selected safety systems had been improperly signed off as complete, the inspector reviewed the completed procedures where the MSTP dates indicated test performance on the same day for more than one train.

Although the inspector did not find any other instances of improper multi-loop signoffs, the adequacy of the MSTP signoff for the TS-required once per cycle automatic initiation of the SBGT system and the system's current operability were questioned. Procedure 8.7.2.1, Measurement of Standby Gas Treatment Filters and Fan Capacity, takes MSTP credit for TS surveillance requirement

4.7.B.1.a.1 for filter and fan capacity and TS 4.7.B.1.a.4 for automatic initiation. The inspector's initial review of the completed procedure performed on January 18, 1994, the day recorded in the MSTP as the last completion date, showed that only one train of the two train system was tested on that day. The licensee was informed of this discrepancy and initiated PR 95.9509. Further efforts located the procedure which was performed for the other train a few days later than the date recorded in the MSTP. Although this showed some discrepancy in the dates recorded in the MSTP, the initial operability concern was addressed and was no longer an issue.

The inspector examined Procedure 8.7.2.1 in more detail and found that it allows MSTP signoff when the automatic initiation portion is not performed, as was the case for the most recent procedure performance. The procedure has two main sections one of which performs the auto initiation and fan and filter capacity check and another which only performs the after filter maintenance capacity check. However, the MSTP uses one node to track both of these TS requirements and the procedure allows signoff of that node after the performance of either of the procedure sections. The most recent performances of the surveillance for each train of SBGT in January 1994 only completed the latter section for capacity. Since Procedure 8.7.2.1 did not satisfy the TS requirement for automatic initiation as performed in January 1994, the licensee reviewed I&C logic surveillance tests performed on the system and discovered that several of them in the aggregate test the system as required by Procedure 8.7.2.1. The inspector reviewed the completed tests and logic diagrams and concluded that both SBGT trains were operable based on the completion of the I&C procedures. The licensee and inspector verified that those procedures are current and the next surveillance will be required in November.

As a result of the aforementioned NRC identified problem, coupled with other deficiencies in the past year involving TS required surveillance, BECo initiated an issue team to reevaluate the adequacy of the TS tracking methodology and revalidate all TS surveillance tasks tracked in the MSTP. The inspector considered this action comprehensive. The results of this reevaluation will be reviewed. **(IFI 50-293/95-21-01)**

3.5 Unexpected Opening of SBGT Dampers During Preventive Maintenance

On October 3, during performance of preventive maintenance (PM) on a breaker for the "A" train of SBGT, the inlet and outlet dampers unexpectedly opened. The maintenance instruction called for racking out the breaker. When the breaker was racked-out, the power to the dampers was lost causing them to open to their fail-safe position. Operators did not expect this change and issued PR 95.9513 to document and evaluate the problem. Work was stopped to rewrite the task to install jumpers to prevent movement of dampers. The "A" SBGT train was already in an LCO action statement for the work, therefore no further operability concerns were identified. The inspector discussed the unexpected damper movement with maintenance personnel. The reason the event was unexpected was ineffective work planning development of the impact matrix in the maintenance request and failure of operators to identify the deficiency. The plant impact matrix indicated that the outlet damper would be affected but not the details of how. It did not mention that there would be any affect on the inlet damper. The requirement to develop a plant impact matrix is specified in procedure 1.5.20, Work Control Process.

The inspector reviewed this violation of failure to follow the requirement of procedure 1.5.20. in accordance with the NRC staff enforcement policy (60 FR 34381, June 30, 1995), and concluded that effective corrective actions were implemented in a timely manner and no safety consequence resulted. This self-identified violation was of minor significance and is dispositioned as a non-cited violation consistent with the enforcement policy. Although the miscommunication of the effect of the PM did not impact safety, it was an example where human performance errors caused an unexpected event.

4.0 ENGINEERING (37551, 92903)

4.1 Residual Heat Removal Valve Leak Identification and Repair

During a residual heat removal (RHR) system inspection on September 27, a system engineer identified a leak (60 drops per minute) coming from the 3/4 inch drain pipe located in the body of valve MO-1001-28B, which is the normally open "B" loop outboard injection valve. The system engineer informed the nuclear watch engineer who declared the "B" RHR loop inoperable and entered the unit into a 7 day shutdown LCO. The leak originated at a weld interface on the drain pipe to the valve body boss connection. Examination of the crack-like indication determined that the structural weld was unaffected. The inspector reviewed Field Revision Notice (FRN) 95-03-144 which provided the necessary reviews and repair instructions and also visually examined the drain pipe. The inservice inspection Class II pressure boundary was restored when a drain pipe was inserted into the valve bore, welded into place and a seal welded threaded pipe cap installed on the end. No visible leaks were observed during conduct of the post work inservice leak test. Operators exited the unit from the shutdown LCO. The inspector concluded that the systems engineer exhibited an excellent problem identification ability and that an effective synergism was evident between engineering, operations and maintenance to facilitate the required repairs.

4.2 (Open) Unresolved Item (50-293/95-21-02): Elevated Salt Service Water (SSW) Temperatures

Elevated salt service water (SSW) inlet temperatures were experienced during this inspection period from August 24 to September 17, 1995. Operators initiated PR 95.9485 to evaluate the effects of the elevated temperatures. The inspector notes that this issue is similar to elevated inlet temperatures experienced during July 1994 as documented in Section 4.3 of NRC Inspection Report No. 50-293/94-14. BECO is in the process of revising the design and licensing basis as a result of the service water inspection of 1994. The issue of elevated SSW inlet temperatures will remain as an unresolved item **(UNR 50-293/95-21-02)** pending further inspector review of the associated operability evaluation and related design and licensing basis.

5.0 PLANT SUPPORT (71750)

5.1 As Low As Is Reasonably Achievable (ALARA) Dose Performance

The original BECo 1995 annual radiation dose goal was 380 Rem and was exceeded during the Spring refueling outage (RFO10). The RFO10 outage ALARA goal was 270 REM, with 410 REM actually used during outage activities. During this inspection period, BECo updated the annual goal and set a new and challenging goal of 490 Rem. To establish the new goal, each work group submitted a dose extension request and an ALARA action plan. The focus of the action plan was to ensure that the revised dose goal would be met. The inspector noted positive initiatives documented in the action plans in the areas of ALARA training, coordination with radiological protection on routine tours to eliminate unnecessary dose, and implementation of permanent shielding packages to reduce general area dose.

The inspector discussed these goals and actual dose numbers with BECo representatives. The original outage estimate, based on radiation work permits, was approximately 390 Rem. The goal was lowered significantly by management to make it extremely challenging to plant personnel. The inspector did note that the outage scope was expanded by 12 percent, making achieving the outage goal difficult. In addition many high dose jobs required re-work including retensioning the vessel head and performing additional under vessel work. Both of these conditions contributed to exceeding the outage ALARA dose goal.

The recently initiated dose reduction action plan focuses the organization on lowering dose. The plan is a "living" document and new items are added to its scope continuously. This plan is discussed in the ALARA Committee meeting as well as with the owners of the specific action items to keep dose reduction goals visible to plant personnel. The inspector reviewed the plan and noted good initiatives for dose reduction including reevaluating routine tours for security and operations, ensuring vendors supply low cobalt content material where possible, and incorporating system flushes into the PM program. The inspector compared the licensee's dose figures to those of similar vintage BWRs and noted that Pilgrim is in the middle of the plants reviewed in their class. (Data was reviewed for three year rolling averages 1991-1993 and 1992-1994.)

The inspector considered BECo's actions to take the time and effort to revise the goal and require the dose extensions for the work groups to include ALARA action plans a positive initiative to refocus plant personnel to keep dose ALARA. The actual dose performance at Pilgrim is comparable to similar vintage plants in the United States. Also, the new dose reduction action plan is a positive initiative to reduce plant dose now and to continue to find ways to reduce it in the future.

5.2 ALARA Committee Meeting

The inspector attended an ALARA committee meeting on September 15, 1995. The inspector noted open discussion among attending plant groups, including operations, station services, maintenance, and QA. Topics included action item list review, flatbed filter upgrade/replacement, ALARA employee of the month selection, and the new dose budget reorganization planned for 1996. The inspector concluded the meeting was an effective means to ensure the action items in the dose reduction action plan are tracked and completed. Also the discussions displayed the members' interest in improving ALARA at the site.

5.3 Radiation Protection Observation

The inspector observed corrective maintenance on the "B" fuel pool cooling pump with specific attention to radiological protection (RP) practices. Maintenance technicians were well briefed prior to commencing work as observed by the inspector and as evidenced by the workers' awareness of radiological conditions in the area and dressout requirements. The maintenance technicians also coordinated well with the RP technician to transport the contaminated pump out of the area and install a clean pump while minimizing the spread of contamination. The inspector observed effective RP practices such as double bagging the contaminated pump, placing bags on the floor to prevent contamination of the cart when it was rolled into the contaminated area, and swiping the cart and pump to determine contamination levels.

The inspector compared the projected dose and time for the work to the actual and found that the estimate enveloped the dose received. In addition the ALARA review and prediction were discussed with responsible personnel. An appropriate method was used which considered past comparable work, projected time to perform the work in the area and current dose rates. The pump replacement was effective in the implementation of RP practices in the field.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (40500)

6.1 Management Effectiveness

A strong management safety perspective was evident during this inspection period. Operations management provided the necessary training and oversight in the implementation of the MELLLA power to flow operations. Operators responded effectively to several challenges at the screenhouse involving fish impingement, mussels and a significant seaweed intrusion event. Plant management initiated an event response team to fully evaluate the significance and opportunities for improvement for the October 6, 1995 seaweed event. Unlike the December 13, 1993 intake structure degraded level event where management did not fully understand the event significance, plant management promptly reviewed the October 6, 1995 event, comparing the computer traces to the previous event and also initiating a event evaluation team. Detailed discussions were held during the Plant Manager's morning meeting relative to this event. Also, the BECo initiation of a 100% MSTP verification effort to address several surveillance issues (including the weakness the NRC identified during this period relating to the testing of the standby gas treatment system) represented a thorough approach.

Plant management interest in minimizing equipment deficiencies was evident. A major HPCI outage improved system reliability by resolving the turbine gland seal blower and SBM control switch issues. Also, during this inspection period, system engineers improved safety by identifying two significant equipment deficiencies involving a RCIC steam line flange leak and a through-wall leak on a residual heat removal outboard injection valve drain pipe. Both deficiencies were promptly repaired and properly included use of TS LCOs. Lastly, the revision to the exceeded annual ALARA goal was a positive management initiative to refocus plant workers on continuing to implement the ALARA principle.

A routine QA audit identified a missed core spray system TS surveillance violation that resulted from a cognitive error made by a senior reactor operator (SRO). The SRO did not implement the established operations surveillance program guidance for partial surveillance test completion. The inspector expressed concern to operations management that this TS violation was similar to a previous TS violation concerning the loss of containment integrity as documented in NRC Inspection Report 94-26 and resulted in an enforcement conference. In that instance, a maintenance surveillance deficiency was missed during final SRO review of the surveillance procedure results. Additionally, the inspectors identified two missed SRO reviews of completed system line-ups during plant start-up from RFO10 (NRC Inspection Report 95-13).

Operations management acknowledged the inspector's concern referencing an emphasis on increased attention-to-detail by SROs during implementation and independent reviews of administrative processes. Contrary to this apparent administrative weakness, the inspector noted the general positive operator performance during special tests and power ascension activities from RFO10. Also, operators responded effectively to several intake structure challenges during this period. Operations management informed the inspector that a contractor will be used, supervised by the QA manager, to more broadly assess the underlying causes of several, minor consequential events experienced during RFO10. The management support to closely evaluate operator performance issues through the use of outside expertise to aid in determining the root cause for recent performance reflects a strong commitment to achieving a high level of reactor safety. The inspector had no further concerns or questions.

7.0 NRC MANAGEMENT MEETINGS AND OTHER ACTIVITIES

7.1 Routine Meetings

Two resident inspectors were assigned to the Pilgrim Nuclear Power Station throughout the period. Backshift inspections were performed on August 24, September 2, October 6 and deep backshift inspections were performed on August 31 and October 7. On August 24 and 25, Mr. William Cook, the NRC Senior Resident Inspector at Vermont Yankee (backup inspector for Pilgrim), visited the site to be badged, meet plant managers and tour the facility. From August 28 to September 1, Mr. Russell Arrighi, NRC Resident Inspector at Millstone Unit 2, provided resident inspector coverage augmentation. Additionally, on August 29 and 30, Mr. Richard Conte, NRC Region I Section Chief for Pilgrim, visited the site to tour the plant, interview senior and plant level managers, and hold discussions with the resident inspectors.

Throughout the inspection, the resident inspectors held periodic meetings and toured portions of the plant with plant management to discuss inspection findings. On October 20, the inspectors held an exit meeting to present their findings and assessments for this period to plant management. No proprietary information was covered in the scope of the inspection. No written material regarding the inspection findings was given to the licensee during this inspection period.

7.2 Other NRC Activities

On August 21 to 24, Mr. James Noggle performed a routine radwaste/transportation inspection. The results of this inspection are documented in NRC Inspection Report 50-293/95-20. Also during that week Messrs. J. Herb Williams and John Caruso conducted an inspection of the licensed reactor operator requalification program. Results of this inspection are documented in NRC Inspection Report 50-293/95-17. Messrs. John Lusher and Dave Silk conducted an emergency preparedness program inspection from August 28 to August 31 which is documented in NRC Inspection Report 50-293/95-18.

On October 3, 1995, the NRC Region I office performed a Plant Performance Review (PPR) for the PNPS, covering the period from October 9, 1994 through September 30, 1995. The PPR consisted of a review of inspection findings, significant events, and other information that related to the licensee organization's performance during the subject period. The purpose of this process was to review nuclear plant performance for trends and to plan future inspection activities at PNPS. A letter communicating the results of this meeting was issued to the licensee on October 19, 1995.