U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos.	50-277, 50-278
License Nos.	DPR-44, DPR-56
Report Nos.	97-08
Licensee:	PECO Energy Company
Facility:	Peach Bottom Atomic Power Station Units 2 and 3
Dates:	November 23, 1997 to January 17, 1998
Inspectors:	A. C. McMurtray, Senior Resident Inspector M. J. Buckley, Resident Inspector B. D. Welling, Resident Inspector R. S. Barkley, Project Engineer J. C. Jang, Senior Radiation Specialist L. L. Eckert, Radiation Specialist G. C. Smith, Senior Security Specialist P. R. Frechette, Security Specialist J. F. Williams, NRR Project Manager

EXECUTIVE SUMMARY

Peach Bottom Atomic Power Station
NRC Inspection Report 50-277/97-08, 50-278/97-08

This integrated inspection report includes aspects of licensee operations; surveillance and maintenance; engineering and technical support; and plant support areas.

Plant Operations:

- Licensee management decided to shutdown Unit 3 and replace the 'E' safety relief valve (SRV) after observing a continuing upward trend in the tailpipe temperature. Management also chose to shutdown Unit 2 to perform electro-hydraulic control (EHC) pressure regulator work. These decisions showed good, conservative, operational decision making. Operator performance during these shutdown and startup evolutions was very good. (Sections O1.2 and 2.1)

- Station preparations for cold weather were performed adequately. However, the inspectors identified a number of discrepancies associated with the documentation and performance of the winterizing routine test procedures, which reflected lapses in formality and attention to detail. The failure of operations personnel to adhere with the requirements in the test procedures resulted in a violation for procedural non-compliance. (Section O2.3)

- Operator performance during two plant transients caused by circulating water system problems was satisfactory. The second transient was initiated by the failure of the 2 'C' circulating water pump discharge valve. PECO's investigations into both events were in progress at the end of this inspection period. The inspectors will review the results of these investigations for maintenance performance issues. (Section O2.4)

- On January 2, 1998, the unit 2 reactor operator failed to perform the technical specification (TS) surveillance requirements (SRs) for verification of proper flow in the recirculation loops. The recirculation loops were not operated outside of the TS requirements during this period. However, it was unclear how station personnel determined that the formal TS SRs were met and why operations personnel failed to review the TSs when unclear information was found in the surveillance test. This issue remains an Unresolved Item (URI) pending additional discussion with operations personnel and final review by the licensee. (Section O3.1)

- During clearance restoration for the diesel driven fire pump, the motor driven fire pump unexpectedly started. The clearance did not contain any cautions regarding the potential for a sudden drop in system pressure to automatically start the motor driven pump and operations personnel performing the clearance removal were not fully aware of this system condition. (Section O3.2)

- On January 1, 1998, the Unit 2 main turbine tripped on main oil pump low pressure during plant start-up after the turbine rolled to a speed of 1400 RPM. Operations personnel were unaware that the turbine had been rolling for over two hours just prior to the trip. This issue appeared to involve a failure of an instrument and control test document to restore the original EHC system alignment after testing and the failure of operations personnel to fully follow procedures. Concerns were also identified with the pulling of control rods to increase reactor pressure during this event and the failure of operations personnel to recognize the status of the main turbine or turbine control systems. This issue remains a URI pending additional reviews of the procedures used during this event, review of strip charts and recorded data from this event, and further discussions with reactor engineering and operations personnel. (Section O4.1)

- On January 7,1998, Unit 2 control room personnel entered an operational transient procedure when a main steam line high radiation alarm was received twice during power ascension. Concerns were identified with the operators incomplete knowledge of the effects of the hydrogen addition system on main steam line radiation during startups and abnormal reactor feedwater alignments. Also, the procedure did not contain instructions to lower the hydrogen addition during this transient. (Section O4.2)

- The inspectors found that a standby liquid control pump discharge valve was in the correct position, but was not locked, as specified by a clearance restoration form. Although of minimal safety impact, this and a second improperly locked valve discovered by the licensee indicated that operators were not always rigorous in independently verifying the condition of locked valves. Corrective actions for this issue were good and included verification of all locked valves in both units. This issue resulted in a Non-Cited Violation (NCV) for procedural non-compliance. (Section O4.3)

Maintenance:

- After the Limerick Generating Station discovered a reactor core isolation cooling (RCIC) inboard steam valve with the wiring to the thermal overload bypass contact lifted, the station tested several motor operated valves looking for this condition. This testing was proactive and showed conservative decision making. Technicians performing the testing displayed good adherence to procedures. (Section M1.3)

- The station missed an opportunity to plan for the removal of foreign material in the 2 'C' residual heat removal system heat exchanger. This material, which included metal straps and an extension cord, was first identified in 1994 and had not been tracked for removal during subsequent maintenance periods. Technicians were surprised when they found this material during maintenance activities in January 1998. (Section M2.2)

- The station and the NRC identified instances where operations were not informed of degraded conditions on safety related equipment in a timely manner. Although

Executive Summary Cont.

some items were minor, one involved an RHR system valve that was declared inoperable after operations became aware of this degraded valve. (Section M3.1)

- On January 4, 1998, main steam line bypass valve, BPV-1, unexpectedly opened approximately 25% several times while the Unit 2 reactor operator was raising reactor power from 96% to 100%. Instrument and control technicians unknowingly introduced a speed error bias in the speed control portion of the EHC system after they tightened a loose connection during replacement activities for the EHC pressure control unit. Instrument and control personnel failed to understand what effect tightening the loose connection on the speed control would have on the speed bias signal and the EHC system. (Section M4.1)

Engineering:

- On December 29, 1997, all nine bypass valves unexpectedly opened at 155 psig EHC pressure during the normal depressurization/cooldown of Unit 2. Operations and engineering personnel failed to understand the effect on the EHC system of a temporary plant alteration which was designed to fail the 'B' EHC pressure regulator and allow replacement of the secondary pressure amplifier card. This lack of system understanding contributed to all the bypass valves unexpectedly opening which resulted in a reactor vessel level transient. (Section E2.1)

- During scheduled maintenance, PECO maintenance personnel identified a broken clutch gear and found a motor brake installed to a Unit 2 residual heat removal valve motor operator. This motor break was to have been removed per an engineering modification in 1988. The broken clutch gear was replaced and the motor brake was removed. The valve was never rendered inoperable due to the installed motor brake. The inspectors will follow-up on the inspections for motor brakes on other valve operators and the results of the failure analyses of the clutch gear. (Section E2.2)

Plant Support:

- Security facilities and equipment were determined to be well maintained and reliable. Security procedures were being properly implemented. Security staff knowledge, performance and training were determined to be acceptable. Security organization, administration and quality assurance programs were adequate to ensure effective implementation of the program. A review of the vehicle barrier system determined the system was installed and being maintained in accordance with applicable regulatory guidance and requirements. (Sections S1 through S8)

TABLE OF CONTENTS

Report Details

Summary of Plant Status

PECO Energy operated both units safely over the period of this report.

Unit 2 began the period operating at 100% power. On December 29, 1997, the unit was shutdown to perform repairs on the main turbine electro-hydraulic control (EHC) system. The unit returned to power operations on January 3, 1998 and on January 4 was only able to reach 96% power due to a speed error bias signal in the EHC control system. On January 6, Unit 2 power was reduced to 90% when condenser vacuum decreased following a trip of the 2 'C' circulating water pump. The unit returned to 100% power on January 9 following adjustments to the speed error bias. On January 14, power was reduced to 97% when condenser vacuum decreased after the 2 'C' circulating water pump failed to start and the pump discharge valve failed open during post-maintenance testing. Power was increased to 100% on January 16 following evaluation of the 2 'C' circulating water pump discharge valve failure and monitoring of Unit 2 condenser vacuum.

Unit 3 began the period operating at 93% power. The unit was operating at less than full power due to recirculation system flow rate limitations because of weld cracks on the jet pump risers. On November 28, 1997, the unit was shutdown to replace the 'E' steam relief valve. The unit returned to power operations on December 1 and reached 93% power on December 5 following relief valve replacement. The unit remained at about 94% power for the remainder of the period, with the exception of load drops on December 7, 10, and 11, to troubleshoot and repair a minor tube leak on the 3 'B' condenser waterbox.

I. Operations

O1 Conduct of Operations[1]

O1.1 General Comments (71707)

Overall, operators responded well to the various load changes and shutdowns on Units 2 and 3 throughout the period. The inspectors observed good communications during load change evolutions and very good response to control board alarms received. Generally, good command and control was observed during these shutdowns and load adjustments. The inspectors observed very good reactivity control during rod manipulations for Unit 2 and Unit 3 during shutdowns and scheduled load swings. However, the inspectors also observed minimal supervisory oversight of the reactor operators during a recirculation pump speed change on Unit 2. The inspectors observed that the shift supervisor was involved in several other activities unrelated to Unit 2 during this reactivity evolution.

The inspectors noted several instances during the period where the operators knowledge of plant systems performance was inadequate and the procedures being

---

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.

used did not provide detailed guidance for the evolution being performed. These unexpected events involved the start of the motor driven fire pump, trip of the Unit 2 main turbine, and Unit 2 main steam high radiation alarms are discussed in Sections O3.2, O4.1, and O4.2, respectively.

In addition, the inspectors identified that operations personnel failed to monitor the temperature of the Unit 2 Condensate Storage Tank (CST) after the CST low temperature alarm annunciated in the control room and was identified as not working properly. Operations personnel initially checked the CST tank and verified that the tank was warm to the touch and that heating to the CST appeared to be working. However, continued monitoring of this CST was not required after this initial check. Outside temperature surrounding the CST was below freezing for several nights prior to the inspectors raising this concern.

O1.2 Unit 3 Plant Shutdown to Replace 'E' Safety Relief Valve

a. Inspection Scope (71707)

The inspectors observed portions of the plant shutdown and startup evolutions for the replacement of the Unit 3 'E' safety relief valve (SRV).

b. Observations and Findings

NRC Inspection Report 50-277(278)/97-07discussed station response and monitoring following the identification of a high temperature on the 'E' SRV tailpipe. PECO took conservative action to shutdown Unit 3 on November 28, 1997 in order to replace the SRV, based on an increasing temperature trend. Inspections of the removed SRV indicated that some leakage had occurred at the secondary stage disc.

The inspectors observed selected portions of the shutdown and startup evolutions on November 28 and December 1. Operator actions during reactivity manipulations were deliberate and controlled. Overall, command and control and management oversight were also very good.

c. Conclusions

PECO management took appropriate, conservative action to shutdown Unit 3 and replace the 'E' SRV after observing a continuing upward trend in the tailpipe temperature. Operator performance during the shutdown and startup evolutions was very good.

O2 Operational Status of Facilities and Equipment

O2.1 Shutdown of Unit 2 Due to Problems with the Electro-Hydraulic Control (EHC) System Pressure Regulator Control

a. Inspection Scope (71707 & 37551)

On December 29, Unit 2 was shutdown to replace the secondary pressure amplifier card and the potentiometer assemblies on the pressure control unit for the 'B' EHC regulator. Several other forced outage repairs were made to Unit 2 equipment, including repairing the external leakage from the reactor feedwater check valve, CHK-2-06-28B. This leakage was a main contributor to the drywell sump inleakage. Instrument and control (I&C) technicians also inspected other subsystems of the EHC system. Challenges from follow-up actions from this inspection are discussed in Section M4.1.

The inspectors observed portions of the plant shutdown and startup and reviewed the safety evaluation and the temporary plant alteration (TPA) associated with the EHC pressure regulator control.

b. Observations and Findings

On December 23, 1997, plant management chose to shut down Unit 2 due to problems with the pressure regulator control circuit. On December 15, the back up EHC pressure regulator 'B' took control of reactor pressure without operator action. Subsequent troubleshooting activities revealed that the 'B' pressure regulator secondary pressure amplifier card operated erratically. These troubleshooting activities also showed noise in the input from the pressure control unit motor-operated potentiometer assemblies indicating degradation. The licensee issued Performance Enhancement Program (PEPs) numbers I000771 and I0007838 to analyze this issue and the December 15 reactivity management event.

On December 20, a TPA was performed per Engineering Change Request (ECR) PB 97-03475, Revisions 000 and 001. This TPA adjusted the pressure control unit potentiometer so that the primary 'A' pressure regulator controlled pressure and failed the 'B' normal/failure switch to the failed position. This action removed the 'B' pressure regulator from service to prevent inadvertent swapping between regulators. This TPA was also written to allow replacement of the secondary pressure amplifier card at power. A plant transient occurred during the shutdown of Unit 2 because this TPA was installed. The transient is discussed in Section E2.2.

A safety evaluation was written to support continued operation of Unit 2 with only the 'A' pressure regulator in service. This safety evaluation addressed the issue raised by the General Electric Services Information Letter (SIL) No. 614, "Backup Pressure Regulator" regarding the potential of being in an unanalyzed condition when a BWR was operated without a back up pressure regulator. The inspectors reviewed this safety evaluation and did not identify any safety concerns.

On December 29, Unit 2 was shutdown to replace the amplifier card and the potentiometer assemblies. Several other forced outage repairs were made to Unit 2 equipment, including repairing the external leakage from the reactor feedwater check valve, CHK-2-06-28B. This leakage was a main contributor to the drywell sump inleakage. Instrument and control technicians also inspected other subsystems of the EHC system. Challenges from follow-up actions from this inspection are discussed in Section M4.1.

The inspectors noted that the decision to replace the pressure regulator, motor-driven, potentiometer assemblies and secondary pressure amplifier card off line instead of at power precluded the possibility of a plant transient due to EHC system problems during replacement work. Also, the inspectors noted that the shutdown allowed repair of CHK-2-06-28B. The inspectors observed good control room performance during the plant shutdown and start-up.

c. Conclusions

The inspectors concluded that the licensee's decision to remove Unit 2 from service to perform the EHC pressure regulator work showed conservative operational decision making. The inspectors also viewed the other repairs performed while the unit was off line as positive.

O2.2 2 'B' Recirculation Pump Speed Control Problems

a. Inspection Scope (71707)

On January 10, 1998, operators observed that the 2 'B' recirculation pump speed and Unit 2 reactor power increased slightly without operator action. The inspectors reviewed operations and engineering staff response to speed control problems with the 2 'B' recirculation pump.

b. Observations and Findings

Operators entered off-normal procedures and initiated a PEP report due to the unexpected reactivity addition when the recirculation pump speed increased. Operators had seen smaller magnitude speed changes on the 2 'B' recirculation pump earlier this year. Monitoring equipment had been installed on the pump motor generator sets to allow for engineering review of this phenomenon. The previous occurrences had been documented on an action request (AR).

Engineering attributed the speed increase to excessive play in the motor generator set speed control linkage. This condition led to unexpected speed changes in the direction of the last change. This condition occurred several hours after a recirculation pump speed was adjusted.

Plant management and operators were aware of the issue, however, some operators were not fully knowledgeable or sensitive to the delayed nature of this reactivity addition phenomenon. The inspectors noted that:

- This was an operationally significant issue, however, operators were not tracking this on the equipment deficiency list (for operationally significant items) in the control room.

- Engineering and operations did not include this on the material condition focus list to ensure management attention on resolution of the issue.

- Some operators recognized this as a workaround, however, this issue was not identified as an operator workaround (OWA) during a recent initiative to document all minor OWAs.

As interim corrective action for this condition, engineering initiated a temporary change to plant procedures to direct operators to turn the controller knob slightly in the opposite direction after making a speed change. This was intended to reduce the potential for the linkage clearance/play to cause speed drifting. Engineering recognized that this was a workaround and was considering options for further repairs or replacement of linkage components. At the end of the inspection period, operations management was still reviewing this issue for possible corrective actions.

The inspectors found that operators responded appropriately after recognizing the minor reactivity addition. While this condition did not lead to a significant reactivity occurrence, it did reveal a continued lack of formality in tracking degraded conditions of low to moderate significance.

The inspectors also noted that although the speed drift problem was first documented in April 1997 and had occurred at least three additional times, neither operations or engineering management had aggressively pursued the resolution of this reactivity management issue. This was evidenced by the lack of inclusion in the material condition focus list and the fact that it was not fully considered for corrective maintenance or troubleshooting during the Unit 2 forced outage in December 1997.

c. Conclusions

Operators responded appropriately to an unexpected speed increase on the 2 'B' recirculation pump and resultant increase in reactor power. However, this event revealed continued weaknesses in operations tracking and understanding of some degraded conditions as noted in Section M3.1 of this report and Inspection Report 50-277(278)-97-07. Additionally, operations and engineering management had not pursued resolution or troubleshooting efforts consistent with similar reactivity management or potential transient initiator issues.

O2.3 Cold Weather Preparations

a. Inspection Scope (71714)

The inspectors reviewed station preparations for cold weather. The following routine test procedures were reviewed: RT-O-040-620-2, Revision 4, "Outbuilding HVAC and Outer Screen Inspection for Winter Operation," and RT-O-040-630-2, Revision 4, "Winterizing Procedure."

b. Observations and Findings

The licensee performed the cold weather preparation's routine test procedures in early October. The tasks covered by the procedures included such items as placing steam heating systems in service, energizing electric heaters, and shutting air supply louvers.

During the review of the completed procedures, the inspectors identified some discrepancies:

- Operators made a number of changes to the procedures in an informal manner. For example, operators noted that several thermostats could not be set to the temperature specified in the procedure, but they did not initiate a temporary procedure change, contrary to instructions on temporary procedure changes. Instead, operators initiated procedure enhancement forms after completing the routine tests.

- No corrective actions were taken for a few deficiencies. For example, some switchgear building air filters were found to be dirty and were marked as unsatisfactory, but no action request (AR) was generated to correct this condition. Other examples involved heaters that did not energize, but the reasons and/or corrective actions were not fully documented.

The inspectors walked down selected areas of the site and verified that the procedures were substantially completed. However, during this spot check, the inspectors observed the following discrepancies:

- Some river outer screen structure heaters (3) were not energized. Maintenance was performed on one of the heaters, but it was not restored to the energized position, as specified by the winterizing procedure.
- Three outer screen structure doors were not fully closed.
- Some outer screen structure door gaskets were damaged or missing.
- Emergency service water booster pump/Cardox building cubicle louvers were open, allowing cold air to be blown directly into the building.

The inspectors discussed these findings with members of the operations staff. Procedure changes were initiated and operators were directed to re-perform portions of the routine test procedure. Operations management acknowledged that the completion of these procedures did not meet department expectations for formality and attention to detail.

The failure of operations personnel to adhere to the routine test procedures for cold weather preparations was a violation of technical specification (TS) 5.4.1. Technical specification 5.4.1 requires, in part, that written procedures are implemented covering the applicable procedures recommended in Regulatory Guide 1.33, Appendix A, November 1972. **(VIO 50-277(278)/97-08-01)**

c. Conclusions

Station preparations for cold weather were performed adequately. However, the inspectors identified a number of discrepancies associated with the documentation and performance of the winterizing routine test procedures that reflected lapses in formality and attention to detail. Concerns with procedural non-adherence were identified in Inspection Report 50-277(278)-97-07. This issue represented a failure of operations personnel to ensure procedural compliance during procedure performance.

O2.4 Circulating Water System Problems (Unit 2)

a. Inspection Scope (71707)

The inspectors reviewed two instances of circulating water (CW) system problems that led to operational transients (OTs).

b. Observations and Findings

On two occasions during this inspection period, CW system problems caused operators to enter OT procedures. On January 6, 1998, the 2 'C' CW pump tripped unexpectedly, and an initial attempt to start the standby 2 'B' CW pump failed.

The second event occurred on January 14, during a retest, following corrective maintenance for the first issue. In this instance, the 2 'C' CW pump did not start due to a failure of the associated discharge valve motor operator, which had recently been repaired. The discharge valve operator motor cracked and broke away from the valve operator during the second event preventing the valve from being closed locally or remotely. This condition caused the 2 'C' pump to rotate in the reverse direction due to CW flow recirculating through this loop.

During both events, operators observed lowering condenser vacuum, entered appropriate off-normal procedures, and reduced reactor power until condenser vacuum stabilized.

Maintenance and engineering personnel initiated investigations to determine the causes of these events. The evaluation for the second event was to include a full root cause analysis. Both investigations were still in progress at the completion of this inspection period.

The inspectors found that operator performance during both transients was satisfactory. The inspectors will assess the results of PECO's investigations for these maintenance performance issues during future inspection activities.

c. Conclusions

Operator performance during two plant transients caused by CW system problems was satisfactory. PECO's investigations into both events were in progress at the end of this inspection period.

The inspectors were concerned with these two non-safety system equipment failures which caused plant transients especially the second event that was caused by the significant failure of the 2 'C' CW pump discharge valve. The inspectors will review the results of these CW system investigations for maintenance performance issues. **(IFI 50-277/97-08-02)**

O3 Operations Procedures and Documentation

O3.1 Missed Technical Specification (TS) Surveillance Requirement (SR) Test for Verification of Proper Flow in the Recirculation Loops

a. Inspection Scope (71707)

On January 2, 1998, the Unit 2 reactor operator failed to perform the TS surveillance requirements (SRs) for verification of proper flow in the recirculation loops. The inspectors reviewed the documentation associated with these missed SRs to determine compliance with TS requirements.

b. Observations and Findings

On January 3, operations personnel discovered that they had missed performing sections of the formal surveillance test that verified that TS SRs 3.4.1.1 and 3.4.1.2 were met. This test, Surveillance Test (ST)-0-02F-560-2, Revision 0, "Daily Jet Pump Operability," verified that the recirculation loops were operating within TS requirements and that the recirculation system jet pumps were operable. This ST verified that the jet pumps were operable by meeting TS SR 3.4.2.1. Unit 2 was in Mode 2, "Startup," at the time the surveillances were missed with the reactor heating up and pressurized to 450 psig per the instructions in General Plant Procedure (GP)-2, Revision 85, "Normal Plant Startup." A surveillance test, ST-0-02F-560-2 was satisfactorily performed on January 3 after the missed SRs were discovered.

Technical specification SR 3.4.1.1 verified that recirculation loop jet pump mismatch was within specifications and TS SR 3.4.1.2 verified that core flow as a function of THERMAL POWER was also within specifications. Both of these SRs were required to be performed in Modes 1 and 2 once per 24 hours. Technical specification SR 3.4.2.1 verified that there was no degradation in jet pump performance; however, this was only required to be performed 24 hours after greater than 25% reactor thermal power was reached. This required the reactor to be in Mode 1, "Power Operation."

The Unit 2 reactor operator determined, based on the wording in ST-0-02F-560-2, that TS surveillances 3.4.1.1 and 3.4.1.2 were also not required to be performed until 24 hours after greater than 25% reactor thermal power. The operator discussed the ST requirements with the control room supervisor and the supervisor agreed after reviewing the ST that the operators' interpretation of the ST was correct. The operator marked the sections of the ST which performed TS SRs 3.4.1.1 and 3.4.1.2 as not applicable.

This event was documented in PEP I0007762. The "Regulatory Review" section of this PEP noted that the licensee determined that TS SRs 3.4.1.1 and 3.4.1.2 were satisfied on January 2 using alternate methods other than the ST-0-02F-560-2. These methods included verifying that SR 3.4.1.2 was satisfied through the data in the operator's daily surveillance log and SR 3.4.1.1 was satisfied by the reactor operator's panel walkdowns and routine operator checks. In addition, parameters on computer printouts showed that recirculation loop jet pump mismatch was within specifications of SR 3.4.1.1. Based on these alternate methods, the licensee concluded that this issue was not reportable.

The inspectors noted during the review of ST-0-02F-560-2 that the ST was unclear and contained conflicting information regarding when each of the TS SRs were required. The inspectors also determined based on the review of the PEP and all other pertinent information that the recirculation loops were not operated outside of the TS SR requirements. However, the inspectors did not understand how the licensee determined that TS SRs 3.4.1.1 and 3.4.1.2 and the requirements of ST-0-02F-560-2 were met since these surveillances were not performed per the ST. The inspectors were concerned with failure of operations personnel to fully understand the requirements of the TSs for the recirculation loops surveillances and to review the TSs when unclear information was found in the ST.

c. Conclusions

The inspectors concluded that the recirculation loops were not operated outside of the TS SR 3.4.1.1 and 3.4.1.2 requirements when the unit 2 reactor operator failed to perform ST-0-02F-560-2 on January 2. However, the inspectors were concerned that operations personnel failed to fully understand when these SRs were required per the TSs. The inspectors were also concerned that the operations personnel failed to review the TSs when unclear and conflicting information was found in the ST. This issue will be tracked as an Unresolved Item (URI) pending additional discussion with the licensee and final determination if the formal TS and ST requirements were met. This will include a review of past practices for complying with these surveillance requirements during startups and shutdowns and the methods used to determine that the requirements were met for this event and the reportability of this event. **(URI 50-277/97-08-03)**

O3.2 Unexpected Start of the Motor Driven Fire Pump During Clearance Removal for the Diesel Driven Fire Pump

a. Inspection Scope (71707)

The inspectors reviewed the clearance documentation and discussed the unexpected start of the motor driven fire pump during diesel fire pump clearance removal with operations personnel.

b. Observations and Findings

On December 8, 1997, the motor driven fire pump auto started while valving in the diesel driven fire pump during clearance removal for Clearance No. 97003830. The clearance permitted various preventive maintenance tasks on the diesel engine and associated valves and instrumentation to be performed.

The inspectors were monitoring control room operations during the clearance removal. While aligning the diesel fire pump, the fire protection water supply system momentarily fell below the low pressure automatic start setpoint for the motor driven fire pump and the pump automatically started. The inspectors questioned operations personnel about whether the start of the fire pump was expected and whether the clearance had any cautions regarding the possible starting of this pump during clearance removal. The inspectors learned that the start of this pump was not expected and that the clearance had no cautions regarding this issue. Subsequently, the motor driven fire pump was secured and the clearance was changed to note this potential condition.

The inspectors were concerned that operations personnel did not fully understand the fire protection water supply system performance and no cautions were contained in the clearance to alert operators to the potential start of the motor driven pump if system pressure dropped during valve re-alignments.

c. Conclusions

The inspectors were concerned that the clearance for returning the diesel driven fire pump back to service did not caution operations personnel that the motor driven fire pump could start during valve realignments due to a sudden drop in system pressure. Also, the operators were not fully aware that this potential unexpected system condition existed.

O4 Operator Knowledge and Performance

O4.1 Unexpected Trip of Unit 2 Main Turbine During Start-up

a. Inspection Scope (71707)

During the Unit 2 reactor startup on January 1, 1998, the main turbine tripped automatically after it was inadvertently rolled to a speed of 1400 rpm. The inspectors reviewed the circumstances leading up to this event, PEP I0007760 and associated procedures from this event, and also discussed this event with operations personnel and plant management.

b. Observations and Findings

On December 31, 1997, to support EHC testing by instrument and control (I&C) personnel, the Unit 2 reactor operator (RO) reset the mechanical trip valve in the main turbine overspeed trip system and selected 1800 rpm on the speed set, at the main turbine (EHC) control panel. The RO also adjusted pressure set to 930 psig during this testing. The I&C test procedure did not provide direction to restore the EHC system configuration to the condition set prior to the testing. Therefore, the main turbine, the pressure set setting, and speed select pushbutton were not restored to the original line-up established by GP-2, Revision 85, "Normal Plant Start-up" prior to the I&C testing.

On the morning of January 1, during the main control panel walkdown portion of shift turnover, the on-coming shift manager noted that pressure set was at 930 psig and directed the RO to readjust the setting to 150 psig (minimum setting). The other two components configuration, however, remained misaligned. Unit 2 reactor was made critical at 5:46 p.m. During the reactor coolant system (RCS) heat-up, when RCS pressure reached 50 psig, the RO was directed by GP-2 to reset the main turbine as per Station Operating procedure (SO) 1B.1.A-2, Revision 22, "Main Turbine Startup and Normal Operation." The RO verified that the main turbine was reset, but did not refer to all of the instructions in SO 1B.1.A-2, which contained instructions to verify that the speed set "ALL VALVES CLOSED" was selected.

At 6:25 p.m. during shift turnover, with RCS pressure at 157 psig, the main turbine control valves opened causing the main turbine to roll off the turning gear unbeknownst to the off-going and on-coming operations personnel. The on-coming RO noted that the turbine was not on the turning gear at about 6:35 p.m. when he cracked opened the 'C' reactor feedwater pump discharge valve to restore a low reactor vessel level condition. Subsequently, the control room supervisor (CRS) directed the RO to commence rod pulls to raise RCS pressure to open the turbine bypass valves. The CRS wanted to raise RCS pressure so that plant conditions would steady out and prevent possible reactor vessel level swings due to turbine bypass valve cycling. No changes in the positions of any of the bypass valves were observed as RCS pressure increased. Just prior to the main turbine trip, the main turbine lube oil high temperature alarm and hydrogen seal oil/stator water cooling trouble alarm were received in the control room.

After the turbine tripped, operations personnel verified that the turbine tripped and placed the turbine on the turning gear. The licensee evaluated any concerns with rolling the main turbine without pre-warming. The licensee determined after discussions with the turbine vendor, General Electric, that the turbine did not experience any distress as a result of this event and was acceptable for long term operation. The licensee documented this event in PEP I0007760.

Several key points in this event concerned the inspectors, including:

- the I&C test procedure did not contain any configuration controls to restore the EHC system to the initial conditions found prior to testing.

- the control room staff did not restore the main turbine, the pressure set setting, and speed select pushbutton to the original line-up established by GP-2, Revision 85, "Normal Plant Start-up" following the I&C testing.

- Inadequate control panel walkdowns occurred over several shifts. Specifically, the main turbine, the pressure set setting, and speed select pushbutton remained mis-aligned until the on-coming day-shift shift manager noted that pressure set was indicating 930 psig on January 1, and the turbine and speed select became self-disclosing during the reactor startup.

- The RO did not adhere to procedure SO 1B.1.A-2, "Main Turbine Startup and Normal Operation" when resetting the main turbine. Specifically, the RO did not verify that "ALL VALVES CLOSED" was selected on the turbine control panel.

- After the RO reported that the turbine was not on the turning gear, he did not monitor his indications to verify the condition of the turbine. The turbine speed was rotating for more than two hours. During this time, none of the operations personnel assigned to Unit 2 observed any of the indications that the turbine was rotating and gaining speed other than coming off of the turning gear.

- The CRS directed the RO to commence rod pulls to raise RCS pressure to open the turbine bypass valves even though he did not understand why the turbine was off of the turning gear and no change in bypass valve position was observed.

- The turbine trip became self-evident to the operations staff after the main turbine lube oil high temperature alarm and hydrogen seal oil/stator water cooling trouble alarm annunciated in the control room.

- The PEP stated that the ROs believed that a dedicated supervisor should have been assigned to oversee the Unit 2 startup evolution. Also, one of the reactor operators thought that the work load was excessive during the startup. Neither of these concerns was expressed by the operators during this evolution.

c. Conclusions

Based on the initial review of this event, the inspectors were concerned with the failure of operations staff to fully understand and recognize the main turbine status and the position of the turbine control valves and the speed select portion of the EHC system. Further, the inspectors were concerned with the pulling of control rods to increase RCS pressure while the turbine condition remained unknown. The inspectors were also concerned with potential deficiencies and lack of coordination between the operations startup and I&C testing procedures and with the rigor of procedure implementation by the operators.

This issue appeared to be a violation of TS 5.4.1, "Procedures" due to the concerns identified above. However, the inspectors needed to conduct additional reviews of the procedures used during this event, review of strip charts and recorded data from this event, and further discussions with reactor engineering and operations personnel. This issue will be tracked as an unresolved Item (URI) pending further review. **(URI 50-277/97-08-04)**

O4.2 Unit 2 Main Steam Line High Radiation Alarms During Power Ascension

a. Inspection Scope (71707 & 37551)

The inspector reviewed the actions of control room personnel for the two main steam high radiation alarms that came in during power ascension following the trip of the 2 'C' circulating water pump and 2 'A' reactor feedwater pump turbine trip testing.

b. Observations and Findings

On January 7, 1998, operators entered Operational Transient (OT) procedure, OT-103, Revision 6, "Main Steam Line High Radiation" on two occasions. The highest main steam line radiation monitoring reading was 1670 mr/hr. The main steam line high radiation alarm setpoint was 1625 mr/hr. Reactor power level at this time was approximately 72%. The main steam line radiation level at this power was normally around 1000 mr/hr. General area radiation levels remained unchanged during this transient. The 2 'A' reactor feedwater pump was not in operation when these transients occurred.

Operators reduced power in accordance with OT-103. After further investigation, operations and engineering personnel determined that the hydrogen addition rates may have been higher than expected for the feedwater flow rates. After discussing this issue with the hydrogen addition system manager, operators manually reduced the hydrogen addition rate to lower the main steam line radiation level to 850 mr/hr or the normal background level for this reactor power value. Operations personnel initiated PEP number I0007782 for this issue.

For many years, the hydrogen addition system was not in service. During the past two years, the system was placed back in service to reduce the effects of intergranular stress corrosion cracking on core components and the recirculation piping.

The inspectors reviewed OT-103 and Station Operating procedure (SO) 15.1.A-2, Revision 0, "Hydrogen Water Chemistry System Startup and Normal Operation." Procedure SO 15.1.A-2 contained a note that the main steam line radiation levels would increase as a result of hydrogen injection. This procedure was used by the operators during the reduction of the hydrogen addition rate. The inspectors also discussed this issue with operations personnel.

The inspectors noted that operations personnel were not fully familiar with the interactions of the hydrogen addition rate on main steam line radiation levels during abnormal reactor feedwater system alignment plant startups. Also, the inspectors noted that OT-103 did not contain any instructions in the procedure to reduce hydrogen addition levels when the high main steam line radiation alarm was received.

c. Conclusions

The inspectors were concerned with the completeness of the operators knowledge of the effects of the hydrogen addition system on main steam line radiation during startups and during abnormal reactor feedwater alignments. The inspectors were also concerned that OT-103 did not contain instructions to lower the hydrogen addition rate if the main steam line high radiation alarm was received. The fact that the system was placed back in service during the past two years after several years of being out-of-service contributed to these concerns.

O4.3 Standby Liquid Control Pump Clearance Restoration

a. Inspection Scope (71707 & 61726)

The inspectors reviewed the post-maintenance testing and clearance restoration performed by operations personnel on the 3 'B' standby liquid control (SBLC) pump.

b. Observations and Findings

The inspectors noted during document review that post-maintenance testing was accomplished by performing a portion of a quarterly surveillance test. The operators observed no adverse conditions during the test.

While verifying the clearance restoration, the inspectors found that one valve was not fully returned to its required status. Specifically, the inspectors observed that the 3 'B' SBLC pump discharge valve, HV-11-13B-3, was open but the lock was not completely engaged. The required position per the clearance restoration sheet was "locked open."

The inspectors brought this deficiency to the attention of operations staff. Operations personnel promptly locked the valve and initiated a verification of other locked valves in the plant. Operators found one additional valve improperly locked on the Unit 2 automatic depressurization system (ADS) backup nitrogen system. In this instance, the lock was engaged, but the chain did not restrain movement of the valve handwheel. Tampering was not suspected in either instance since the valves were in their proper positions.

The inspectors noted that the SBLC pump clearance restoration form required independent verification of the valve positions, and the verifications were documented as completed. Operations staff interviewed the operator who did the independent verifications and found that he stated that he had performed the expected actions to verify the position of valve. However, it was evident that both the individual who positioned the valve and the independent verifier did not carefully check that the lock was fully latched.

The inspectors determined that PECO took appropriate corrective actions for this issue. Upon discovering a second improperly locked valve, operations management directed that full verifications of all accessible locked valves in the plant be accomplished. No additional problems were discovered during this review. Management communicated this issue to all operators and other site personnel who have cognizance over locked components. The discrepancies had minimal safety impact and did not affect system operability since the valves were in their correct position.

The failure of operations personnel to fully adhere to the instructions in clearance number 97003684 during restoration for the 3 'B' SBLC pump was a violation of TS 5.4.1. Technical specification 5.4.1 requires, in part, that written procedures are implemented covering the applicable procedures recommended in Regulatory Guide 1.33, Appendix A, November 1972. However, this NRC identified violation was of minor safety significance and is being treated as a Non-Cited Violation (NCV), consistent with Section IV of the NRC Enforcement Policy **(NCV 50-277(278)/97-08-05).**

c. Conclusions

The inspectors found a standby liquid control pump discharge valve in the correct position, but not locked, as specified by the clearance restoration form. Although of minimal safety significance, this and a second improperly locked valve discovered by the licensee indicated that operators were not always rigorous in independently verifying the condition of locked valves. Corrective actions for this issue were good and included verification of all locked valves in both units.

O7 Quality Assurance in Operations

O7.1 Plant Operations Review Committee (PORC) Meeting

The inspectors observed two PORC meetings during the inspection period. The PEP evaluation root cause for the September 1997, 3 'B' Circulating Water Pump fire was discussed at the first meeting. The problems and corrective actions associated with the reactor feedwater pump high level failure to trip and the EHC transient observed during the late December 1997 Unit 2 shutdown was discussed at the second meeting. The inspectors noted good questioning attitude by licensee management during these PORC meetings. Questions asked by the managers to personnel presenting these issues were thorough and reflected in-depth safety focus into issues discussed.

II. Maintenance and Surveillance

M1 Conduct of Maintenance and Surveillance

M1.1 Standby Liquid Control Pump Maintenance

a. Inspection Scope (62707)

The inspectors observed corrective maintenance performed on the 3 'B' standby liquid control (SBLC) pump. Post-maintenance testing and clearance restoration for this job was discussed in Section O4.3.

b. Observations and Findings

The inspectors observed work performed per corrective maintenance work order number C0177825 on the 3 'B' SBLC pump. Technicians investigated a minor oil leak on a pump motor bearing and repacked the pump seals after discovering indications of slight leakage past the seals.

Technicians followed the requirements of the work order and maintenance procedures. After consulting with their supervisor, they determined that the bearing oil leak was negligible, and no further work was required. The technicians were knowledgeable, and the supervisor provided oversight as needed. The inspectors noted that the technicians documented their work on the work order.

c. Conclusions

The inspectors observed that maintenance technicians working on the 3 'B' standby liquid control pump were knowledgeable, well-supervised, and followed the maintenance procedures.

M1.2 Unit 3 Primary Containment Local Leakage Rate Testing (LLRT) Review (61726)

The inspector reviewed SE-CM-01, "Primary Containment Leakage Rate Testing Implementation Plan, Rev. 0" and ST/LLRT 20.00.01, Revision 0, "Local Leak Rate Tests (LLRTs) Documentation and Tracking," to evaluate the results of the LLRTs performed during the Unit 3 outage. These procedures also implemented the performance-based testing schedule provisions of the recently published Option B of 10 CFR 50, Appendix J. This review found that the overall maximum pathway integrated local leak rate was approximately 0.426 La (i.e., the maximum allowable leakage rate at the calculated peak containment internal pressure during a design basis accident) versus the acceptance criteria of 0.6 La. Discussions with the LLRT coordinator and a review of LLRT scheduling information indicated that only 40% of all Type B & C tests had their testing interval extended under the Option B provisions such that they did not require testing during the Unit 3 outage as originally scheduled. Overall, the LLRT program appeared consistent with the provisions of Option B, was well controlled and indicated good preventive maintenance of containment isolation valves as indicated by the successful overall test results.

M1.3 Motor Operated Valve Thermal Limit Bypass Operability

a. Inspection Scope (61726 & 62707)

The inspectors observed testing of several motor operated valve (MOV) thermal bypasses. The licensee performed this testing at Peach Bottom after a reactor core isolation cooling (RCIC) inboard steam valve was discovered with the wiring to the thermal overload bypass contact lifted at the Limerick Generating Station.

b. Observations and Findings

Normally, the control circuits on MOVs for automatically operated isolation valves are arranged so that motor thermal overload protection is provided. During certain accident conditions, this protection is bypassed to prevent automatically initiated valve operation from being interrupted by the motor thermal overload. This thermal overload bypass is provided to allow the valve to reach the required position during an accident.

When the RCIC MOV deficiency was found at Limerick, the licensee discovered that their testing method checked both the thermal overload "seal-in" leg and the thermal bypass at the same time without separating out the individual contacts. Therefore, the condition of the RCIC thermal bypass contact went undetected since the contact was not being tested separately. There is no requirement for this type of testing at Peach Bottom, however, engineering personnel conservatively determined that a verification test of the MOVs would be prudent.

The licensee successfully tested the thermal overload bypass function on 22 MOV isolation valves at Peach Bottom. No deficiencies were identified with the thermal overload bypass circuitry for these valves. This population of MOVs represented a sampling of approximately 10% of all valves with thermal overloads at the station. Engineering personnel determined that this was a sufficient population to obtain confidence that the rest of the thermal overloads for MOVs were installed correctly. The licensee planned to incorporate thermal overload bypass testing during the next normally scheduled test for MOVs.

The inspectors observed testing of the thermal overload bypass function on selected MOVs. The bypasses functioned properly and maintenance personnel accomplished the testing in accordance with approved procedures. The maintenance personnel maintained effective and precise communications between the control room and work stations.

c. Conclusions

The inspectors concluded that testing of the thermal overload bypass function on selected MOVs was proactive and showed conservative decision making. The testing observed provided a good functional test of the bypass contact. The inspectors also concluded that technicians displayed good adherence to procedures during testing.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Standby Liquid Control Pump Crankcase Oil Viscosity

a. Inspection Scope (62707)

The inspectors reviewed the discovery of a higher than expected oil viscosity in the 3 'A' SBLC pump.

b. Observations and Findings

On December 11, 1997, technicians found that the viscosity of the oil in the 3 'A' SBLC pump crankcase was significantly higher than expected. The oil sample result indicated the viscosity value was 160 centistoke (cSt), while the expected value was 68 cSt. Operations re-sampled the oil to confirm the result. Since the high viscosity value made the operability of the pump questionable, operators declared the pump inoperable and entered the appropriate TS action statement. Technicians drained and flushed the crankcase and then refilled it with the correct oil specified by the lubrication program and the pump overhaul procedure.

After further review, predictive maintenance technicians found that the oil viscosity had been high since April 1996. To address the generic implications of this issue, management directed that other SBLC pumps be sampled and that oil viscosity values of all plant rotating equipment be reviewed for abnormal values. No problems were identified for other safety-related components.

PECO also found that predictive maintenance technicians had previously evaluated the 3 'A' SBLC pump high oil viscosity and had received correspondence from the pump vendor that indicated that pump operation would not be adversely affected by the high viscosity oil. However, the technicians did not formally document this information at that time. After the December finding and subsequent review of data, engineering concluded that the pump remained operable with the high viscosity oil.

The inspectors determined that operations took appropriate, conservative immediate actions to declare the SBLC pump inoperable. The inspectors also reviewed the interim and planned long-term corrective actions for this issue and identified no concerns. Predictive maintenance personnel initiated improvements to their review and documentation processes.

c. Conclusions

Operations took conservative action when they declared the 3 'A' standby liquid control pump inoperable following the discovery of higher than expected viscosity oil in the pump crankcase. Investigation by PECO revealed that this condition had been previously evaluated by predictive maintenance personnel, but had not been formally documented. Initial corrective actions to replace the oil, evaluate pump operability, and review viscosity records on other plant components were satisfactory.

M2.2 Foreign Material in 2 'C' Residual Heat Removal System Heat Exchanger

a. Inspection Scope (62707 & 37551)

The inspectors reviewed PECO maintenance technicians' discovery of foreign material in the 2 'C' residual heat removal (RHR) system heat exchanger.

b. Observations and Findings

On January 5, 1998, during maintenance on the 2 'C' RHR heat exchanger, technicians found broken glass, an electrical extension cord, and metal straps on the RHR (shell) side of the heat exchanger. Technicians removed the glass but were unable to remove the cord and metal straps.

After further investigation, PECO determined that the foreign material had been previously identified in the heat exchanger in 1994. At that time, engineering evaluated the material through a non-conformance report (NCR) and dispositioned it as "use-as-is." This NCR provided an evaluation which allowed the foreign material to remain in the heat exchanger for an indefinite period of time. However, maintenance did not initiate any action to track this condition and plan for the removal of this material during subsequent maintenance periods. The inspectors learned during discussions with PECO management that they recognized this as a missed opportunity.

The inspectors noted that maintenance has now taken steps to track foreign material conditions and similar interim "use-as-is" dispositions. Maintenance determined that this will allow maintenance planning to include activities to attempt to remove foreign material, as appropriate, during normally scheduled work.

The inspectors also reviewed the NCR generated as result of this issue. The inspectors discussed the report with engineering staff and found that the evaluation considered both normal and post design basis accident operation of the RHR heat exchanger. Engineering concluded that the function of the heat exchanger was not adversely affected, and that deterioration or movement of the material was highly unlikely.

c. Conclusions

The inspectors had no concerns with operation of the RHR heat exchanger during normal and post design basis accident conditions with the foreign material still present based on the NCR review. This material, which included metal straps and an extension cord, was first identified in 1994 and had not been tracked for removal during subsequent maintenance periods.

However, the inspectors concluded that PECO missed an opportunity to plan for the removal of foreign material in the 2 'C' RHR heat exchanger during the regularly scheduled maintenance work. Thus, technicians did not expect to find this foreign material during maintenance activities in January 1998.

M3 Maintenance Procedures and Documentation

M3.1 Equipment Condition Notification to Operations

a. Inspection Scope (62707)

The inspectors reviewed the process for notifying operations personnel of corrective maintenance problems and degraded equipment conditions. The inspectors referred to AG-CG-026.2, Revision 4, "Corrective Maintenance Action Request Initiation and Processing."

b. Observations and Findings

NRC Inspection Report 50-277(278)/97-07 discussed an instance of poor equipment status control, in which a standby safety-related station battery charger had been in a degraded, inoperable condition for several months, but was not being tracked by operations personnel. After further review by operations staff, they concluded that they were not notified of the further degradation of this equipment in a timely manner.

During this inspection period, both PECO and the NRC identified similar examples in which operations were not fully informed of degraded conditions on safety-related equipment. Examples included the following:

- Maintenance noted a degraded condition on an RHR system motor operated valve breaker, and the maintenance supervisor considered the component operable. The AR for the problem was not routed to operations in a timely manner for an operability determination. When operators reviewed the condition, they declared the valve inoperable. Operations raised concerns about the untimely routing for the operability determination. Shortly after the valve was declared inoperable; maintenance corrected the breaker problem and the valve was made operable.

- The inspectors noted that ARs for packing leakage on safety related instrument root valves were not routed to operations for operability determinations

- The inspectors found that an AR on an RCIC steam line outboard isolation valve was not routed to operations for an operability determination.

The inspectors discussed these findings with operations and maintenance staff. Following the discussion, operations initiated a PEP report to review the issue and developed corrective actions to communicate these issues to appropriate plant supervision.

c. <u>Conclusions</u>

The station and the NRC identified instances where operations staff were not informed of degraded conditions on safety-related equipment in a timely manner. The inspectors were concerned that the failure to inform operations of these degraded conditions could result in operations personnel being aware of potentially inoperable equipment. Some items identified during this inspection were of minor significance; however, one issue involved an RHR valve that was declared inoperable by operations after they became aware of the degraded condition on this valve.

M4 Maintenance Staff Knowledge and Performance

M4.1 <u>Unit 2 EHC Speed Error Signal Bias Due to Repair of Speed Control Card Short</u>

a. <u>Inspection Scope (62707 & 37551)</u>

On January 4, 1998, main steam line bypass valve, BPV-1, unexpectedly opened approximately 25% several times while the Unit 2 reactor operator was raising reactor power using control rods. Unit 2 was at approximately 96% power and reactor pressure was stable at 1028 psig when this occurred. The inspectors reviewed this issue and the licensee corrective actions that allowed Unit 2 to reach 100% power.

b. Observations and Findings

During replacement activities for the EHC pressure control unit, the I&C technicians discovered a short circuit on a card in the speed control section of the EHC system. This short was due to a loose connection on the card. The instrument and control technicians tightened the connection and reinstalled the card.

During subsequent troubleshooting of this issue, I&C personnel discovered 0.5 volts in the speed error circuitry that was producing a 15% speed error signal. This signal should have shown 0% speed error. This condition was documented on AR number A1128229.

Ongoing analysis of this condition by engineering and I&C personnel indicated that the 15% speed error was caused by the repair to the speed control card loose connection. Retightening this connection was believed to have introduced the speed error since this error had earlier been unknowingly compensated due to the short.

Engineering personnel issued a non conformance report (NCR) under ECR number 98-00036, Revision 000 to raise the load set value from 105% to 120% to compensate for the speed error. This allowed the required 105% value to come out of the summer for speed control and load control. This ECR contained a safety evaluation for operating the unit with this change to the load set value. Several operations procedures were also changed to reflect the revised nominal indicated margin between the load set and actual power due to the speed bias.

Subsequently, the load set was raised and unit 2 power was increased to 100% on January 8.

The inspectors reviewed the ECR, safety evaluation, and AR for this condition and verified that the affected operations procedures had been changed. The inspectors had no concerns with the change to the load set. However, the inspectors noted during these reviews that I&C personnel did not fully understand the effect on the EHC system of tightening the loose connection on the card in the speed control section.

c. Conclusions

The inspectors had no concerns with the analysis or changes made to increase the load set value to compensate for the speed error bias. However, the inspectors were concerned with the failure of the I&C personnel to fully understand the operation of the speed control circuitry and what effect tightening the loose connection would have on the signal and the EHC system.

III. Engineering

E1 Conduct of Engineering

E1.1 Unit 3 Jet Pump Riser Elbow Weld Cracking

a. Inspection Scope (37551)

The inspectors reviewed the interim operating strategy, safety evaluation, and flaw evaluation for the cracks found in the jet pump risers during the October 1997, Unit 3 refueling outage.

b. Observations and Findings

Engineering personnel performed an assessment of the cracks on the jet pump risers and determined that the reactor could be returned to service and operated on an interim basis pending repairs, with restrictions on recirculation flow to limit crack growth by fatigue. The licensee described its interim operating strategy in a letter dated October 30, 1997. The Office of Nuclear Reactor Regulation (NRR) staff requested additional information on November 7, 1997, which the licensee provided on November 17, 1997. The licensee provided a revised interim operating strategy on November 19, 1997. This interim strategy was implemented under the provisions of 10 CFR 50.59, and limits recirculation flow to 91% for up to 800 hours, and 80% for 2,224 hours.

The NRR staff agreed with the licensee that no unreviewed safety question existed. The staff concluded that the licensee's flaw evaluation is in accordance with Appendix C to Section XI of the ASME Code, and that ASME Code component structural integrity margins would be maintained for the specified operating period under the interim operating strategy. The staff noted that the licensee reserved 18.4% margin in terms of final crack length to account for uncertainties and inaccuracies in its evaluation. This margin gave the staff additional assurance that the facility could be safely operated until repairs are performed.

On December 22, 1997, the licensee documented its decision to use a mechanical clamp as the permanent crack repair, and that a repair outage is scheduled for early March 1998. The licensee committed to inform the NRC of changes to the operating strategy which require revision of the 10 CFR 50.59 safety evaluation. The licensee will provide a summary of actual operating history documenting actual recirculation flow rates and time periods under the interim strategy following the repair outage.

c. Conclusions

The licensee's flaw evaluation for cracks found on the jet pump risers was in accordance with the ASME code and provided adequate margin for continued safe operation of Unit 3. The inspectors had no concerns with the licensee's safety evaluation or interim operating strategy.

E2 Engineering Support of Facilities and Equipment

E2.1 Inadvertent Operation of Bypass Valves During Unit 2 Shutdown

a. Inspection Scope (71707 & 37551)

On December 29, 1997, all nine bypass valves unexpectedly opened at 155 psig EHC pressure during lowering of the 'A' EHC pressure set from 190 psig to 150 psig during the normal depressurization/cooldown of Unit 2. The inspectors reviewed TPA performed per ECR number PB-03475, Revisions 000 and 001 which contributed to this event and Operations General Procedure [GP]-3, Revision 77, "Normal Plant Shutdown."

b. Observations and Findings

While lowering EHC pressure to allow a depressurization of the Unit 2 reactor to less than 50 psig, all bypass valves opened. The reactor pressure was 120 psig at the time. The EHC pressure set was immediately raised until all the bypass valves closed. EHC pressure was then lowered at 1.0 psig increments. At 156 psig, six bypass valves opened up. Pressure set was then raised to 159 psig and all six bypass valves closed again. During these changes in EHC pressure, pressure control swapped from the 'A' regulator to the 'B' regulator.

During this transient, reactor vessel level swelled from a steady-state of +22.0" to +50.0" then back to +22.0." The 2 'A' reactor feedwater turbine tripped automatically during this transient. This issue is discussed in section E2.1.

The licensee's investigation into this transient revealed that the TPA that removed the 'B' pressure regulator from service helped cause this event. This TPA failed the 'B' normal/failure switch by installing a jumper which closed the failure switch. With this failure switch closed, the lower 1 kilohm resistor in the circuit shorted out when the pressure set point was lowered. This condition tied the voltage signal to ground since the resistance was shorted out. This caused the 'A' regulator voltage signal to be lower than the 'B' signal so that the 'B' regulator took control and resulted in all the bypass valves opening. After the vessel was depressurized, the licensee jumpered the 'A' normal/failure switch and was able to duplicate the circuit behavior with the 'A' pressure regulator circuitry. This TPA was removed and the 'B' pressure regulator motor-operated potentiometer assemblies and secondary pressure amplifier card was replaced prior to start-up.

After reviewing the TPA and operations procedures, the inspectors noted that this event was another example of the failure of the operators and engineering personnel to understand what effect the work document had on the system. Specifically, operations and engineering personnel did not fully understand the effect of the TPA on the EHC system. The inspectors noted that the TPA was written to replace the "B" pressure regulator card at power and not while shutdown. The inspectors determined that the failure to fully understand the effect of the TPA during shutdown conditions inhibited operations personnel from adding procedural cautions in the shutdown procedures. These cautions would have provided additional assurance that the pressure regulation and turbine-generator control system operated as required during the shutdown evolution.

c. Conclusions

The inspectors were concerned with the failure of operations and engineering personnel to understand the effect on the EHC system of the TPA which was designed to fail the 'B' EHC pressure regulator and allow replacement of the secondary pressure amplifier card. This lack of system understanding contributed to all the bypass valves unexpectedly opening which resulted in a reactor vessel level transient.

E2.2 2 'C' Residual Heat Removal (RHR) Pump Suction to Torus Valve Motor Operator Deficiencies

a. Inspection Scope (62707 & 37551)

During scheduled maintenance, PECO maintenance personnel identified a broken clutch gear and found a motor brake installed to the RHR Torus suction valve motor operator, MO-2-10-013C. The inspectors reviewed applicable documentation and discussed these issues with engineering and maintenance personnel to understand the causes and corrective actions for these deficiencies. The inspectors also independently evaluated whether these deficiencies were applicable to other valves.

b. Observations and Findings

While the 2 'A' RHR system was out-of-service, maintenance personnel found what appeared to be a motor brake electrical connection on the 2 'C' RHR Torus suction valve operator motor. Engineering personnel verified that the motor break was installed. Review of this issue by engineering personnel revealed that the motor brake installed on this valve was to have been removed by an engineering modification in 1988. This engineering modification was also supposed to remove the brakes from several other safety-related valve operator motors. The RHR system electrical drawing, M-1-S-65, Revision 96, "Unit 2 Wiring Diagram: Electrical Schematic Diagram RHR System," did not show this electrical brake to the 2 'C' RHR Torus suction valve operator motor.

Maintenance removed the motor brake from MO-2-10-013C prior to testing and wrote PEP I0007785 to document this deficiency. Maintenance planned to change the MOV maintenance procedure to add a step to verify that no motor brakes were installed.

The inspectors reviewed NRC Information Notice 93-98, "Motor Brakes on Valve Actuator Motor." This Information Notice discussed the potential for MOVs with motor brakes installed to fail if the design basis voltage was insufficient during a degraded voltage condition to allow the motor brakes to release. The inspectors noted that the design basis voltage to the 2 'C' RHR pump suction to the torus, MO-2-10-013C, was verified during the preventive maintenance program on the MOV.

During testing of this valve, the maintenance personnel noticed an abnormal noise coming from the valve operator in the tripper finger area where the lever for conversion to manual operation is located. Subsequently, maintenance personnel disassembled and inspected the valve operator and found a part of a tooth missing from the worm shaft clutch gear. The worm shaft clutch gear and the grease in the operator were removed and replaced. The knob which contacted the tripper fingers was filed down to correct the noise problem. The valve operator was reassembled and the valve was successfully retested and returned to service.

The inspectors observed portions of the valve operator's disassembly, reassembly, and testing. The inspectors observed that the tooth breakage on the worm shaft clutch gear ran though the stamp mark on the end of the gear.

c. Conclusion

Based on the performance history and voltage available during an accident to the 2 'C' RHR pump torus suction valve, the inspectors concluded that the installed motor brake did not render this valve inoperable. However, the inspectors were concerned that other safety-related MOVs could have motor breaks installed even though the breaks had supposedly been removed per the 1988 engineering modification. The inspectors will follow-up on the identification and inspection of other MOVs for motor brakes, any modification control issues concerning the 1988 engineering modification, and any generic implications from the results of the failure analyses on the broken worn shaft clutch gear. **(IFI 50-277(278)/97-08-06)**

E8 Miscellaneous Engineering Issues

E8.1 (Closed) URI 50-277(278)/96-04-04: Emergency Diesel Generator (EDG) Output Breaker Response During Testing

On June 6, 1996, operations personnel identified an unexpected condition during a simulator exercise that affected all four EDGs. While any EDG was running and unloaded, the output breaker would fail to automatically close following a loss of offsite power. Generally, this was only possible during EDG testing prior to paralleling the diesel to the grid. This condition was caused by a seal-in of the 4 KV breaker anti-pumping features and had unknowingly been introduced into the control circuit logic in June 1995 during modification P-231. Modification P-231 was designed to provide automatic transfer from the EDG parallel mode to the isochronous mode of operation. The EDG output breaker could be shut during this condition by momentarily placing the breaker in the trip position to clear the anti-pump relay seal-in.

Interim corrective actions included: declaring the EDGs inoperable during testing; training operations personnel and revising procedures to specify the required actions to shut the EDG output breaker; and performing additional analyses to identify other potential scenarios where the EDG output breaker would lockout.

The inspectors had no concerns with the interim actions, however, the inspectors were concerned with any safety and regulatory significance associated with this design condition. These concerns were forwarded to NRR for review.

NRR visited the Peach Bottom site and reviewed the electrical distribution system control and schematic diagrams and the current licensing basis. NRR concluded that the safety significance of this design condition was low and the licensee remained in compliance with the Technical Specifications during routine EDG testing. NRR also determined that the EDG remained within the licensing basis and was not required to respond to a loss of coolant accident or a loss of offsite power while in this condition. NRR identified no new issues during this review. Based on the NRR review and the licensee's interim corrective actions, the inspectors have no further concerns with this issue.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Implementation of the Radioactive Liquid and Gaseous Effluent Control Programs

a. Inspection Scope (84750-01)

The inspection consisted of: (1) a tour of the plant, including the control room, (2) review of liquid and gaseous effluent release permits, and (3) review of unplanned/unmonitored release pathways, if any.

b. Observations and Findings

The inspectors toured Units 2 & 3, selected effluent radiation monitoring systems (RMS), selected air cleaning systems, and the control room. All effluent RMS and air cleaning systems were operable at the time of this inspection.

Radioactive liquid and gas release permits contained: (1) gamma measurement results; (2) tritium measurement results; (3) projected dose calculation results; (4) cumulative dose contributions from radioactive gas and liquid releases for the current calendar quarter; (5) RMS readings (before, during, and end of release); and

(6) aler and alarm setpoints. The inspectors determined that the licensee followed associated procedures and the requirements of the Offsite Dose Calculation Manual (ODCM).

The licensee completed a significant upgrade to the chemistry laboratory including non-radiological measuring equipment. Another notable improvement to the radioactive effluent's program was new laboratory quality control software.

c. Conclusions

Based on the above reviews, the inspectors determined that the licensee implemented the radioactive liquid and gaseous effluent control programs effectively.

R2 Status of Radiological Protection and Chemistry Facilities and Equipment

R2.1 Calibration of Effluent/Process Radiation Monitoring Systems (RMS)

a. Inspection Scope (84750-01)

The inspectors reviewed the most recent calibration results (electronic and radiological calibrations) for the following effluent and process RMS with respect to licensee procedures, Technical Specifications (TS) and ODCM requirements:

- Liquid Radwaste Effluent Monitor (common),
- Liquid Radwaste Effluent Flow Meter,
- Reactor Building Closed Component Cooling Monitors (both units),
- Service Water Effluent Monitors (both units),
- Emergency Service Water Effluent Monitor (common),
- Main Stack Noble Gas Monitors (common, normal and wide range),
- Roof Vent Noble Gas Monitors (both units),
- Offgas Monitors (both units)

The inspectors also reviewed the most recent radiological calibration results performed by the Chemistry Department staff for the following process RMS:

- Control Room Vent Monitor,
- Refuel Floor Vent Exhaust Monitors (both units), and
- Drywell High Range Monitors (both units)

b. Observations and Findings

The Instrumentation and Controls (I&C) Department performed both the electronic and the radiological portions of RMS calibrations. Calibration results were within the licensee's acceptance criteria.

The inspectors noted no inadequacies pertaining to the calibration of the liquid radwaste effluent flow meter.

During a review of older RMS (manufacturers other than Sorrento), the inspectors noted that radiological calibrations were good, linearity checking was good, high voltage was properly set by determining the optimum high voltage set point, and electronic alignments were appropriate. Tracking and trending efforts by the system engineer were very good.

During a review of newer RMS (manufactured by Sorrento), the inspectors noted that the radiological calibration techniques used by the licensee were acceptable because beta scintillator detectors are inherently stable. Linearity checking was good. Tracking and trending efforts by the system engineer were very good. However, the electronic portion of the calibration of these monitors was weak. High voltage was checked at one point, but the inspectors noted that these RMS continually self-monitor high voltage. Electronic alignment checks were minimal. This was discussed with the System Engineer who agreed to review the matter and make changes to calibration procedures as appropriate.

c. Conclusions

Based on the above evaluation, the inspectors concluded that this program area was good. A minor weakness was noted pertaining to the electronic portion of a calibration of RMS manufactured by Sorrento.

R2.2 Surveillance Tests for Air Cleaning and Ventilation Systems

a. Inspection Scope (84750-01)

The inspectors reviewed the licensee's: (1) most recent surveillance test results, and (2) performance summaries with respect to Technical Specification (TS) and Updated Final Safety Analysis Report (UFSAR) requirements for the control room, standby gas treatment, and turbine building ventilation systems.

b. Observations and Findings

The inspectors noted that deficiencies identified during surveillance testing were corrected and as-left conditions met the licensee's acceptance criteria.

The licensee periodically checked and recorded the differential pressure across turbine building ventilation HEPA filters.

The licensee's TS specify Regulatory Position C.6.a of Regulatory Guide (RG) 1.52, Revision 2, March 1978, as the requirement for the laboratory testing of the charcoal. RG 1.52 references ANSI N509-1976, "Nuclear Power Plant Air-Cleaning Units and Components." ANSI N509-1976 specifies that testing is to be performed in accordance with paragraph 4.5.3 of RDT M-161T, "Gas Phase Adsorbents for

Trapping Radioactive Iodine and Iodine Components." The most recent test results met the licensee's existing charcoal test acceptance criteria. Charcoal efficiency testing was conducted by a vendor service. The inspectors informed the licensee of alternative charcoal testing methodologies.

c. Conclusions

The inspectors concluded that the licensee maintained a good program for air cleaning systems.

R3 Radiological Protection and Chemistry Procedures and Documentation

a. Inspection Scope (84750-01)

An ODCM review was conducted that consisted of: (1) review of set point calculation methodologies; (2) review of selected parameters for calculating projected doses; and (3) review of radioactive liquid and gaseous discharge pathways. The inspectors also reviewed the 1996 Annual Radioactive Effluent Report to verify implementation of the TS/ODCM.

b. Observations and Findings

The ODCM contained set point calculation methodologies for radioactive liquid and gaseous effluent RMS. The inspectors also noted that the ODCM contained all relevant parameters as found in Regulatory Guide 1.109, NUREG-0133, and site specific factors. Radioactive liquid and gaseous effluent pathway diagrams were also provided as required. No new ODCM discrepancies were noted (see Section R8.2).

The Annual Radioactive Effluent Report provided total quantities of liquid and gaseous effluent released from both units and included projected doses to the public. The inspectors determined that the licensee met the TS/ODCM reporting requirements and the report contained the information specified in the ODCM. No obvious omissions, trends or anomalous measurements were identified.

c. Conclusions

The licensee's ODCM contained all the necessary information and guidance to support the radioactive liquid and gaseous effluent control programs. No discrepancies were noted pertaining to the Annual Radioactive Effluent Report. All liquid and gaseous discharges for 1996 were well within regulatory requirements.

R7 Quality Assurance (QA) in Radiological Protection and Chemistry Activities

a. Inspection Scope (84750-01)

The inspection consisted of reviews of the most recent TS required radioactive effluents control program audit, surveillances, and a Chemistry Department self-assessment.

The inspectors reviewed the radiochemistry laboratory quality assurance/quality control (QC) programs to determine the adequacy of controls with respect to sampling, analyzing, and evaluating data. The inspectors reviewed results pertaining to: (1) the intra laboratory and inter laboratory comparison; (2) blind duplicate samples; (3) reproduction techniques (reproducibility for sampling and analyzing); and (4) instrument control charts.

b. Observations and Findings

The 1997 QA Audit was effective and adequately covered the effluent control program including ODCM implementation. A technical specialist with applicable experience was on the audit team. No findings of regulatory significance were identified.

No discrepancies were noted pertaining to the intra-laboratory, inter-laboratory, or blind-sampling comparative tests. Laboratory QC data results indicated that the licensee implemented very good quality control of Chemistry laboratory counting equipment.

c. Conclusions

Quality assurances of the effluents control program and quality control of chemistry sampling analysis and detection equipment was considered to be very good.

R8 Miscellaneous Radiological Protection and Chemistry Issues

R8.1 Unreviewed Safety Question Review and Radioactive Effluents Control (VIO 50-278/97-03-01)

In NRC Inspection Report 50-278/97-03, it was noted that the licensee did not formally consider potential impacts regarding radioactive effluents control prior to breaching the turbine building that resulted in a violation. The inspectors reviewed the licensee's response to NOV 50-278/97-03-01 and considered the corrective actions to be reasonable. The inspectors verified the corrective actions and changes had been made by the licensee to better address the need for considering impacts on the radioactive effluent's control program during the modification review process. Based on this review, the violation is closed.

In addition to the corrective actions implemented to address the violation, Chemistry department personnel conducted a thorough walkdown of the turbine building and identified several perforations and seam cracks in the roof. Licensee staff analyzed each to determine whether the differential pressure at each location was either positive or negative. The licensee established continuous sampling stations at each of the holes where the differential pressure was positive. At the time of the inspection, work orders had been initiated for repair and the engineering department was conducting a safety evaluation of the existing condition. No major safety consequence is expected.

R8.2 Tour of Peach Bottom Unit 1

On December 4, 1997, the inspectors toured the decommissioned Unit 1 facility. This plant was a 40 MWe, high temperature, gas-cooled reactor and was shutdown in October 1974. All fuel for this reactor has been removed from the site. The inspectors did not identify any significant concerns with the maintenance of Unit 1 during this tour.

S1 Conduct of Security and Safeguards Activities

a. Inspection Scope (81700)

Determine whether the conduct of security and safeguards activities met the licensee's commitments in the NRC-approved security plan (the Plan) and NRC regulatory requirements. Areas inspected were: access authorization program; alarm stations; communications; protected area access control of personnel and packages and material.

b. Observations and Findings

Access Authorization Program. The inspectors reviewed implementation of the Access Authorization (AA) program to verify implementation was in accordance with applicable regulatory requirements and Plan commitments. The review included an evaluation of the effectiveness of the AA procedures, as implemented, and an examination of AA records for seven individuals. Records reviewed included both persons who had been granted and had been denied access. The AA program, as implemented, provided assurance that persons granted unescorted access did not constitute an unreasonable risk to the health and safety of the public and that appropriate actions were taken when persons were denied access or had their access terminated.

Alarm Stations. The inspectors observed operations in both the Central Alarm Station (CAS), and the Secondary Alarm Station (SAS). This observation included alarm response, post turnover, and interviews with the alarm station operators. The alarm stations were equipped with appropriate alarms, surveillance and communications capabilities and were continuously manned by knowledgeable operators. No single act could remove the plant's capability for detecting a threat and calling for assistance because the alarm stations were sufficiently diverse and independent. The Central Alarm Station (CAS) did not contain any operational activities that could interfere with the execution of the detection, assessment and response functions.

Communications. Both alarm stations were capable of maintaining continuous intercommunications, communications with each security force member (SFM) on duty, and calling for assistance from both on and offsite organizations. These communications capabilities have been enhanced by the recent acquisition and installation of more powerful radios in security and emergency vehicles.

Protected Area (PA) Access Control of Personnel and Hand-Carried Packages. The inspectors observed operations at the personnel access portal a number of times during the course of the inspection. Positive controls were in place to ensure only authorized individuals were granted access to the PA. All personnel and hand-carried items entering the PA were properly searched and the last SFM controlling access to the PA was in a position to perform this function effectively.

PA Access Control of Material. The inspectors observed material processing in the warehouse. The licensee had positive control measures for all materials entering the PA. Materials entering the PA were identified, searched and authorized by the licensee. Materials entering the PA via the warehouse were searched by properly trained and qualified individuals.

c. Conclusions

The licensee was conducting its security and safeguards activities in a manner that protected public health and safety and that this portion of the program, as implemented, met the licensee's commitments and NRC requirements.

S2 Status of Security Facilities and Equipment

a. Inspection Scope (81700)

Areas inspected were: Testing, maintenance and compensatory measures; PA detection and assessment aid; personnel and package search equipment and vehicle barrier systems.

b. Observations and Findings

Testing, Maintenance and Compensatory Measures. The inspectors reviewed testing and maintenance records for security-related equipment and found that documentation was on file to demonstrate that the licensee was testing and maintaining systems and equipment as committed to in the Plan. A priority status was being assigned to each work request and repairs were normally being completed within the same day a work request necessitating compensatory measures was generated. The inspectors reviewed security event logs and maintenance work requests generated over the last year. These records indicated that the need for compensatory measures was extremely minimal. When necessary, the licensee implemented compensatory measures that did not reduce the effectiveness of the security system as it existed prior to the need for the compensatory measure.

PA Detection and Assessment Aids. The inspectors observed the licensee's performance test of the entire Intrusion Detection System (IDS). All zones of the IDS were tested, and generated appropriate alarms. The test of the IDS was accomplished in accordance with the established testing procedure. The IDS was functional and effective. The inspectors observed camera coverage, in the CAS, of the entire perimeter, while it was being walked down. The camera coverage and overlap were very good. The licensee's assessment aids were functional and effective.

Personnel and Package Search Equipment. The inspectors observed both the routine use and the daily performance test of the licensee's personnel and package search equipment. All search equipment was observed to perform its intended function.

c. Conclusions

The licensee's security facilities and equipment were determined to be well maintained and reliable and were able to meet the licensee's commitments and NRC requirements.

S3 Security and Safeguards Procedures and Documentation

a. Inspection Scope (81700)

Areas inspected were: security program plans, implementing procedures and security event logs.

b. Observations and Findings

Security Program Plans. The inspectors verified that selected changes to the Plan associated with the vehicle barrier system (VBS), as implemented, did not decrease the effectiveness of the Plan.

Security Program Procedures. Review of selected implementing procedures associated with the VBS determined the procedures were consistent with the Plan commitments, and were properly implemented.

Security Event Logs. The inspectors reviewed the Security Event Log for the previous six months. Based on this review, and discussion with security management, it was determined that the licensee appropriately analyzed, tracked, resolved and documented safeguards' events.

c. Conclusions

Security and safeguards' procedures and documentation were being properly implemented. Event Logs were being properly maintained, and effectively used to analyze, track, and resolve safeguards events.

S4 Security and Safeguards Staff Knowledge and Performance

a. Inspection Scope (81700)

Areas inspected were security staff requisite knowledge and capabilities to accomplish their assigned functions.

b. Observations and Findings

Security Force Requisite Knowledge. The inspectors observed a number of SFMs in the performance of their routine duties. These observations included alarm station operations, personnel and package access control searches, and PA patrols. In addition, interviews were conducted with SFMs and security management. Finally, training records were reviewed (see **S5**). Based on all of the above activities, it was determined that the SFMs were knowledgeable of their responsibilities and duties, and could effectively carry out their assignments.

Response Capabilities. The inspectors reviewed the licensee's response strategies, response drills and critiques and evaluated feedback to the training department for lessons learned.

c. Conclusions

The SFMs adequately demonstrated that they have the requisite knowledge necessary to effectively implement the duties and responsibilities associated with their position.

S5 Security and Safeguards Staff Training and Qualifications

a. Inspection Scope (81700)

Areas inspected were security training and qualifications and training records.

b. Observations and Findings

Security Training and Qualifications. The inspectors reviewed training records of ten SFMs and observed weapons' qualifications for two SFMs. The records review and weapons' qualification observation indicated that the security force was being trained in accordance with the approved T&Q plan.

Training Records. The inspectors' review of training records determined that the records were accurate and contained sufficient information to determine the current qualifications of the individual.

c. Conclusions

Security force personnel were being trained in accordance with the requirements of the NRC approved T&Q plan. Training records were being properly maintained. Finally based upon the findings documented in paragraph S4, the inspectors determined that the training was effective and provided the security force with the requisite information needed to effectively implement the Plan.

S6 Security Organization and Administration

a. Inspection Scope (81700)

Areas inspected were: management support, effectiveness and staffing levels.

b. Observations and Findings

Management Support. The inspectors reviewed various program enhancements made since the last program inspection to determine the level of management support. These enhancements included the allocation of resources for the following activities:

- Upgrade of the offsite communications system to include installation of new more powerful radios in six security and emergency vehicles.
- Upgrades to the assessment system, including the installation of six new pan tilt and zoom video cameras and a new video switcher.
- Installation of an upgraded video-capture system to enhance assessment capabilities.
- Training of onsite Instrument and Control Technicians to repair radio communications systems, therefore, reducing the need for offsite support in maintaining these systems.

Management Effectiveness. The inspectors reviewed the management organizational structure and reporting chain. Security managements position in the organizational structure provides a means for making senior management aware of programmatic needs. Senior management's positive response to requests for equipment, training and resources in general have contributed to the effective administration of the security program.

Staffing Levels. The inspectors verified that the total number of trained SFMs immediately available on a shift met the requirements specified in the Plan

c. Conclusions

The level of management support was adequate to ensure effective implementation of the security program, and was evidenced by adequate staffing levels and continued resource allocation to improved training and equipment to enhance effective implamentation of the security program.

S7 Quality Assurance in Security and Safeguards Activities

a. Inspection Scope (81700)

Areas inspected were: audit/self-assessment program, problem analyses, corrective actions and effectiveness of management controls.

b. Observations and Findings

Audit/Self-Assessment Program. The inspectors reviewed the licensee's Security Program Audit Report (Assessment A1061530 conducted March 24-April 7, 1997) and Fitness-for-Duty (FFD) Audit Report (Assessment A1102592 conducted

August 2-October 2, 1997). There were no findings in the security audit and one deviation identified during the FFD audit.

The deviation was not indicative of major programmatic weaknesses. The FFD audit was enhanced by the use of technical specialists. Finally, a review of the response to the audit finding indicated that the actions taken to address the finding would enhance program implementation.

The self-assessment program was well defined and structured. Self-assessments were performed in the areas of security operations, access controls, security systems and training. The self-assessments were comprehensive, and results well documented. The data generated was trended, and the results were well organized.

Problem Analyses. The inspectors reviewed data derived from the self-assessment program. The analyses was effective, and problem areas are trended and identified.

Corrective Actions. The inspectors reviewed corrective actions implemented by the licensee in response to the internal QA audit. The corrective actions were effective, and should prevent recurrence of the findings associated with the corrective actions.

Effectiveness of Management Controls. The inspectors observed that the licensee has a program in place which was effective in identifying, analyzing and resolving problems. The corrective actions taken by the licensee, in response to the audit findings were adequate and should prevent recurring problems. The same could be said for the self-assessment program relative to the ability of the licensee to identify and analyze problems.

c. Conclusions

The review of the licensee's Audit/Self-Assessment program indicated that the audits were comprehensive in scope and depth, that the audit findings were reported to the appropriate level of management, and that the program was being properly administered. In addition, the corrective actions that were implemented were effective.

S8 Miscellaneous Security and Safety Issues

S8.1 Vehicle Barrier System (VBS) (TI 2515/132)

General

On August 1, 1994, the Commission amended 10 CFR Part 73, "Physical Protection of Plants and Materials," to modify the design basis threat for radiological sabotage to include the use of a land vehicle by adversaries for transporting personnel and their hand-carried equipment to the proximity of vital areas and to include the use of a land vehicle bomb. The amendments require reactor licensees to install vehicle control measures, including vehicle barrier systems (VBSs), to protect against the malevolent use of a land vehicle. Regulatory Guide 5.68 and NUREG/CR-6190 were issued in August 1994 to provide guidance acceptable to the NRC by which the licensees could meet the requirements of the amended regulations.

A February 28, 1996, letter from the licensee to the NRC forwarded Revision 8, to its physical security plan. The letter stated, in part, that vehicle control measures meet the criteria of 10 CFR 73.55(c)(7), (8) and (9) and Regulatory Guide 5.68 dated August 1994. A NRC June 19, 1996, letter advised the licensee that the changes submitted had been reviewed and were determined to be consistent with the provisions of 10 CFR 50.54(p) and were acceptable for inclusion in the NRC-approved security plan.

This inspection, conducted in accordance with NRC Inspection Manual Temporary Instruction 2515/132, "Malevolent Use of Vehicles at Nuclear Power Plants," dated January 18, 1996, assessed the implementation of the licensee's vehicle control measures, including vehicle barrier systems, to determine if they were commensurate with regulatory requirements and the licensee's physical security plan.

S8.2 Vehicle Barrier System (VBS)

a. Inspection Scope (TI 2515/132)

The inspectors reviewed documentation that described the VBS and physically inspected the as-built VBS to verify it was consistent with the licensee's summary description submitted to the NRC and was in accordance with the provisions of NUREG/CR-6190.

b. Observations and Findings

The inspectors' walkdown of the VBS and review of the VBS summary description disclosed that the as-built VBS was consistent with the summary description and met the specifications in NUREG/CR-6190.

c. Conclusion

The inspectors determined that there were no discrepancies in the as-built VBS or the VBS summary description.

S8.3 Bomb Blast Analysis

a. Inspection Scope (TI 2515/132)

The inspectors reviewed the licensee's documentation of the bomb blast analysis and verified actual standoff distances provided by the as-built VBS.

b. Observations and Findings

The inspectors' review of the licensee's documentation of the bomb blast analysis determined that it was consistent with the summary description submitted to the NRC. The inspectors also verified that the actual standoff distances provided by their as-built VBS were consistent with the minimum standoff distances calculated using NUREG/CR-6190. The standoff distances were verified by actual field measurements.

c. Conclusion

No discrepancies were noted in the documentation of bomb blast analysis or actual standoff distances provided by the as-built VBS.

S8.4 Procedural Controls

a. Inspection Scope (TI 2515/132)

The inspectors reviewed applicable procedures to ensure that they had been revised to include the VBS.

b. Observations and Findings

The inspectors reviewed the licensee's procedures for VBS access control measures, surveillance and compensatory measures. The procedures contained effective controls to provide passage through the VBS, provide adequate surveillance and inspection of the VBS, and provide adequate compensation for any degradation of the VBS.

c. Conclusion

The inspectors' review of the procedures applicable to the VBS disclosed no discrepancies.

S8.5 Security Force Strike Contingency Plans

a. Inspection Scope (TI 2515/132)

Evaluate the licensee's strike contingency plans to verify that trained personnel are available to support staffing levels consistent with staffing requirements and that plans are in place to insure security operations continue in a safe and orderly manner in the event of a strike.

b. Observations and Findings

The inspectors reviewed the licensee's contingency plan to be implemented in the event of a strike, and reviewed training and qualification records for contingency force personnel that were available to replace striking officers in the event of a strike.

c. Conclusion

The licensee had taken appropriate action to insure that an adequate number of trained and qualified personnel were available to meet regulatory required staffing levels and continue security operations in a safe and orderly manner in the event of a strike.

F1 Control of Fire Protection Activities

F1.1 Fire in the 2 'C' Service Air Compressor

a. Inspection Scope (71707, 62707, & 71710)

The inspectors reviewed the station response to a fire in the 2 'C' service air compressor on December 11, 1997.

b. Observations and Findings

Operators responded to a fire in the 2 'C' service air compressor at about 3:20 a.m. on December 11, 1997. The fire was extinguished within five minutes and was limited to the compressor motor. PECO conducted a critique of the fire brigade response and considered that overall efforts were good, but found some opportunities for improvement in communications between the control room and the fire brigade.

PECO discovered that the fire was most likely caused by an inboard bearing cage failure and subsequent overheating of the bearing. The inspectors reviewed the maintenance history on the air compressor and found that annual preventive maintenance had been conducted as scheduled.

In early November, predictive maintenance technicians identified noisy bearings and high vibration on the compressor motor. The motor was placed on an increased monitoring frequency (biweekly). Further readings in early December indicated increasing vibration amplitudes and maintenance technicians recommended that the motor be worked before its scheduled preventive maintenance date of May 1998. The maintenance was tentatively re-scheduled for March 1998. Based on review of the vibration data, maintenance technicians did not believe that failure was imminent, so they did not request a higher priority for this corrective maintenance issue.

The inspectors discussed the issue with the preventive maintenance technicians and independently reviewed the bearing vibration data. The inspectors determined that the data did not show signs of imminent failure. The inspectors had no concerns with the priority the maintenance group placed on this issue based on information reviewed.

c. Conclusions

The station fire brigade response to a fire in the 2 'C' service air compressor motor was good; however, operations identified some opportunities to improve communications between the control room and the fire brigade. The inspectors reviewed predictive maintenance activities on this component and identified no concerns. Technicians had been monitoring increased motor bearing vibration, but the data did not indicate that a failure was imminent.

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 January 20, 1998. The licensee acknowledged the findings presented.

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

X2 Review of Updated Final Safety Analysis Report (UFSAR) Commitments

A discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters. Since the UFSAR does not specifically include security program requirements, the security inspectors compared licensee activities to the NRC-approved physical security plan, which is the applicable document. While performing the security inspection discussed in this report, the inspectors reviewed Chapter 3 of the Plan titled, "Protected Area Perimeter." Based on discussions with security supervision, procedural reviews, and direct observations, the inspectors determined that barriers were installed and maintained as described in the Plan and applicable procedures.

LIST OF ACRONYMS USED

action request (AR)
action statement (AS)
administrative guideline (AG)
APRM gain adjust factor (AGAF)
as-low-as-reasonably-achievable (ALARA)
average power range monitors - neutron (APRMs)
central alarm system (CAS)
control rod drives (CRDs)
control room emergency ventilation (CREV)
core power and flow log (CPFL)
core spray (CS)
core thermal power (CTP)
design input document (DID)
electro-hydraulic control (EHC)
eleventh refueling outage (3R11)
emergency core cooling system (ECCS)
emergency diesel generator (EDG)
emergency operating procedures (EOP)
emergency preparedness (EP)
emergency service water (ESW)
end-of-cycle (EOC)
engineering change request (ECR)
engineered safety feature (ESF)
fitness-for-duty (FFD)
fix-it-now (FIN)
functional testing (FT)
general procedure (GP)
Generic Letter (GL)
health physics (HP)
high efficiency particulate (HEPA)
high pressure coolant injection (HPCI)
high pressure service water (HPSW)
hydraulic control unit (HCU)
improved TS (ITS)
independent safety engineering group (ISEG)
inservice inspection (ISI)
inspector follow-up items (IFIs)
instrument and control (I&C)
intermediate range monitor - neutron (IRM)
intrusion detection systems (IDS)
licensee event report (LER)
limited senior reactor operators (LSROs)
limiting conditions for operation (LCO)
load tap changer (LTC)
local leak rate test (LLRT)
loss of coolant accident (LOCA)
loss of off-site power (LOOP)

low pressure coolant injection (LPCI)
lubricating oil (LO)
main control room (MCR)
modification (MOD)
motor generator (MG)
nuclear maintenance division (NMD)
nuclear quality assurance (NQA)
NRC-approved physical security plan (The Plan)
nuclear review board (NRB)
offsite dose calculation manual (ODCM)
offsite power start-up source #2 (2SU)
offsite power start-up source #3 (3SU)
Peco Energy (PECO)
performance enhancement program (PEP)
plant operations review committee (PORC)
post-maintenance testing (PMT)
primary containment (PC)
primary containment isolation system (PCIS)
primary containment isolation valve (PCIV)
protected area (PA)
quality assurance (QA)
quality control (QC)
radiation monitoring system (RMS)
radiologically controlled area (RCA)
radiological protection and chemistry (RP&C)
rated thermal power (RTP)
reactor core isolation cooling (RCIC)
reactor engineer (RE)
reactor feed pump (RFP)
reactor operator (RO)
reactor protection system (RPS)
reactor water cleanup (RWCU)
reliability centered maintenance (ROM)
residual heat removal (RHR)
safety evaluation report (SER)
safety related structures, system and components (SSC)
safety relief valve (SRV)
scram solenoid pilot valve (SSPV)
secondary alarm system (SAS)
secondary containment (SC)
security force members (SFM)
senior reactor operator (SRO)
shift technical advisor (STA)
shift update notice (SUN)
source range monitor (SRM)
specific gravity (SG)
spent fuel pool (SFP)
standby gas treatment (SGTS)
standby liquid control (SLC)
station blackout (SBO)

structure, system and component (SSC)
surveillance requirement (SR)
surveillance test (ST)
systems approach to training (SAT)
technical requirements manual (TRM)
technical specification (TS)
temporary plant alteration (TPA)
training and qualification (T&Q)
turbine bypass valve (BPV)
turbine control valve (TCV)
turbine stop valve (TSV)
undervoltage (UV)
unresolved item (URI)
updated final safety analysis report (UFSAR)
vehicle barrier system (VBS)
wide range neutron monitoring system (WRNMS)

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering Observations
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observation
IP 71707:	Plant Operations
IP 71750:	Plant Support Observations
IP 81700:	Physical Security Program for Power Reactors
IP 84750-01	Radioactive Waste Treatment, and Effluent and Environmental Monitoring
IP 92700:	Onsite Follow of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901:	Operations Follow-up
IP 92902:	Follow-up - Engineering
IP 92903:	Follow-up - Maintenance
IP 92904:	Plant Support Follow-up
IP 93702:	Prompt Onsite Response to Events at Operating Power Reactors
TI 2515/132:	Malevolent Use of Vehicles at Nuclear Power Plants

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-277/97-08-01	VIO	Cold Weather Preparations Procedural Non-compliance
50-278/97-08-01	VIO	Cold Weather Preparations Procedural Non-compliance
50-277/97-08-02	IFI	Unit 2 Circulating Water System Problems
50-277/97-08-03	URI	Missed TS SR Test for Verification of Proper Flow in the Recirculation Loops
50-277/97-08-04	URI	Unexpected Trip of Unit 2 Main Turbine During Start-up
50-277/97-08-05	NCV	Procedure Non-Adherence: Minor Safety Significance
50-278/97-08-05	NCV	Procedure Non-Adherence: Minor Safety Significance
50-277/97-08-06	IFI	Review of Failure to Remove MOVs Motor Breaks and Broken Worm Shaft Gear Failure Analysis

50-278/97-08-06	IFI	Review of Failure to Remove MOVs Motor Breaks and Broken Worm Shaft Gear Failure Analysis

Closed

50-277/97-08-05	NCV	Procedure Non-Adherence: Minor Safety Significance
50-278/97-08-05	NCV	Procedure Non-Adherence: Minor Safety Significance
50-277/96-04-04	URI	EDG Output Breaker Response During Testing
50-278/96-04-04	URI	EDG Output Breaker Response During Testing
50-278/97-03-01	VIO	Inadequate Safety Evaluation for Unit 3 Turbine Building Modification