U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-387/86-27; 50-388/86-30

Docket Nos. 50-387 (CAT C); 50-388 (CAT C)

License Nos. NPF-14; NPF-22

Licensee: Pennsylvania Power and Light Company

2 North Ninth Street

Allentown, Pennsylvania 18101

Facility Name: Susquehanna Steam Electric Station

Inspection At: Salem Township, Pennsylvania

Inspection Conducted: December 2, 1986 - January 5, 1987

Inspectors: L. R. Plisco, Senior Resident Inspector

J. Stair, Resident Inspector

Approved By: J. T. Wiggins, Chief, Reactor Projects Section 1B, DRP — 2-9-87 date

Inspection Summary:

Areas Inspected: Routine resident inspection of plant operations, licensee event followup, open item followup, surveillance, and maintenance.

Results: Unit 1 was manually shutdown twice due to increasing unidentified RCS leakage caused by valve packing leaks (Detail 3.3); Unit 2 was manually shutdown due to excessive CIG leakage caused by MSIV operator lubricant breakdown (Detail 3.4); a Unit 1 Containment Radiation Monitor was misaligned due to an uncontrolled drawing (Detail 3.6); Standby Gas Treatment System does not contain potential single failure mechanism's as identified at other facilities (Detail 6.0); and, the Traversing Incore Probes have caused two unplanned shutdowns, but the failures were not related (Detail 7.0).

One violation was identified concerning inoperability of a station battery supplying common loads (Detail 3.5).

DETAILS

1.0 Followup on Previous Inspection Items

1.1 (Closed) Unresolved Item (388/84-34-10): Standby Gas Treatment System Performance During Loss of AC Power Event

During the Loss of AC Power Event at Unit 2, in July 1984, the Standby Gas Treatment System (SGTS) fans tripped unexpectedly. The licensee performed an evaluation of the operation of SGTS during the transient to complete scram action item 2-84-04-13.

The SGTS initiated as designed during the transient when the RPS MG sets coasted down causing a primary and secondary containment isolation signal. The SGTS fans were aligned to Unit 1 power supplies which did not lose power, and both fans started since they are both normally aligned in 'auto lead'. When initiated by a Unit 2 isolation signal, the ventilation dampers are designed to open to allow SGTS to drawdown Zone II (Unit 2 Reactor Building) and Zone III (common refueling floor). However, these dampers lost power on the loss of the Unit 2 4KV buses and did not open. Hence, the SGTS fans could not drawdown Zone II and the fans then tripped on low reactor building differential pressure.

Although the loss of all AC power in one unit, followed by a LOCA in the other unit is beyond the SGTS design basis, the licensee evaluated the desireability of the low differential pressure trip signal. Licensee review found that the original purpose of the trip was to trip the fan in 'auto lead' and allow the fan in 'standby' to start. Since the system design now requires both fans to be in 'auto-lead', the trip signal was found to be unnecessary. The licensee decided to eliminate the low vacuum trip of the fan trains to increase the overall reliability of the system. Plant Modification Record (PMR) 84-3102, which removed the trips, was completed on June 4, 1986.

The inspector reviewed portions of the completed modification package and verified the associated drawings have been revised.

1.2 (Closed) Inspector Followup Item (387/84-38-03): Control of Combustibles Needs Reemphasis by Licensee Management

During a review of station controls for combustible materials, the inspector noted that the administrative procedures in place to review and approve temporary or permanent storage of combustible materials were not being consistently implemented. Specifically, several examples of unattended combustible material were noted, and a Combustible/Hazardous Material Storage Request was not approved.

In response, the licensee issued several station memoranda to reemphasize the use and storage of combustibles. The memoranda were reviewed with the work planners, first line supervisors and work groups. During the last two refueling outages, the inspectors reviewed the control of combustibles and no discrepancies were identified, indicating that the reemphasis by licensee management has been effective.

1.3 (Closed) Violation (387/83-20-01): Failure to Complete Surveillances on Containment Atmosphere Monitors

In July 1983, the licensee reported that one train of the particulate and gaseous containment atmosphere monitors was inoperable, while the other train was not surveilled for operability. In addition, grab samples were not taken for backup analysis as required by Technical Specifications. This was another example of a recurring problem with failures to perform Technical Specification required surveillances, and a management meeting was held on August 30, 1983 to discuss the NRC's concerns. A violation was issued for not adequately performing 15 surveillance tests due to inadequate procedures, missing procedures, and failure to perform required tests over a period of 11 months.

In response to the violation, the licensee established a Surveillance Review Group. This group was tasked with: reviewing and revising the Technical Specification/Surveillance Cross-Reference Matrix; verifying the scope of issued surveillance procedures; developing and documenting station positions and definitions relating to surveillance testing; and, developing highlighted logic drawings. The licensee compliance group also increased staffing related to surveillance testing oversight. The Nuclear Safety Assessment Group performed a thorough review of the program and methodologies and provided recommendations for improvement.

As a result of the licensee's corrective programs, the tracking, scheduling, and technical adequacy of surveillance testing has greatly improved. The number of LER's relating to surveillance program deficiencies has been significantly reduced. During the most recent SALP period only 4 LER's were submitted which described missed surveillances, compared with 15 LER's reported in the previous period.

The inspector reviewed the licensee's current administrative procedures and Surveillance Cross-Reference Matrix and has conducted detailed technical reviews of several surveillance procedures during the last year. The licensee's actions have been effective in preventing recurring missed surveillances. In addition, ongoing programs and controls have been effective in maintaining the established program.

1.4 (Closed) Unresolved Item (387/83-19-03): Inadequate Management Control of a Known Plant Deficiency (LER 83-036 and 83-153)

In March 1983, the licensee reported that a 10 Amp fuse providing power to the RCIC Topaz Inverter had blown. The inverter supplies power to RCIC instrumentation and speed control circuitry at the remote shutdown panel. LER 83-036, dated March 24, 1983 and an update dated August 10, 1983 discussed four occurrences over a five month period where the fuse was found to be blown. The inspector discussed the LER with the plant staff and stated that it appeared to be an example where inadequate management control of a known plant deficiency had resulted in a relatively simple problem not being corrected for approximately six months.

In a followup to the unresolved item, in Inspection Report 50-387/85-21; 50-388/85-17, the inspector determined that the fuse had been found blown an additional four times and effective corrective action had not been implemented. In addition, previous reviews of the licensee's actions in Inspection Report 50-387/83-19 and 50-387/84-26 found that the licensee had not vigorously pursued resolution of this continuing problem. Based on these reviews, the licensee was requested to reply to these concerns in writing and to provide a corrective action schedule.

The licensee responded to the concern in a letter dated September 13, 1985 (PLA-2532). The licensee stated that the modification to change the RCIC topaz inverter circuitry to assure a reliable power source had been completed. The modification changed the Unit 1 circuitry to be similar to Unit 2 which had not experienced the blown fuse problems.

The inspector verified that the modification was installed. No occurrences of blown fuses have been recorded since installation of the circuit modification.

1.5 (Closed) Inspector Followup Item (388/84-28-04): Procedural Deficiencies During Remote Shutdown Panel Demonstration

On July 5, 1984, the inspector witnessed Unit 2 startup test ST 28.1, Shutdown and Cooldown Demonstration. The startup test demonstrated the remote shutdown and subsequent cooldown of the reactor using control devices located outside the control room. During observation of the test several procedural deficiencies were noted and several problems were identified with hardware and labels on the remote shutdown panel.

The labeling deficiencies were corrected during the Unit 2 first refueling outage, which was completed in October 1986. The emergency operating procedure EO-200-009, Plant Shutdown from Outside the Control Room, was revised to provide consistent terminology with the

installed controls and indications. The procedure was also revised to correct inaccurate and/or incomplete operating instructions identified during the test.

During the test, it was determined that a design error existed, in that the "A" recirculation pump suction valve was required to be operated when placing the "A" RHR loop in the shutdown cooling mode, but only the controls for the "B" recirculation pump discharge valve were installed on the remote shutdown panel. It was later determined that the "A" recirculation pump suction valve could be operated from outside the control room at the local breaker panel, and the emergency procedure has been revised to provide for remote operation. The inspector reviewed the revised emergency operating procedure and performed a walkdown of the remote shutdown panel, with no further discrepancies noted.

2.0 Review of Plant Operations

2.1 Operational Safety Verification

The inspector toured the control room daily to verify proper manning, access control, adherence to approved procedures, and compliance with LCOs. Instrumentation and recorder traces were observed and the status of control room annunciators was reviewed. Nuclear Instrument panels and other reactor protection systems were examined. Effluent monitors were reviewed for indications of releases. Panel indications for onsite/offsite emergency power sources were examined for automatic operability. During entry to and egress from the protected area, the inspector observed access control, security boundary integrity, search activities, escorting and badging, and availability of radiation monitoring equipment.

The inspector reviewed shift supervisor, plant control operator and nuclear plant operator logs covering the inspection period. Sampling reviews were made of tagging requests, night orders, the bypass log, Significant Operating Occurrence Reports (SOORs), and QA nonconformance reports. The inspector observed several shift turnovers during the period.

No unacceptable conditions were identified.

2.2 Station Tours

The inspector toured accessible areas of the plant including the control room, relay rooms, switchgear rooms, cable spreading rooms, penetration areas, reactor and turbine buildings, diesel generator building, ESSW pumphouse, the security control center, and the plant perimeter. During these tours, observations were made relative to equipment condition, fire hazards, fire protection, adherence to procedures, radiological controls and conditions, housekeeping,

security, tagging of equipment, ongoing maintenance and surveillance and availability of redundant equipment.

No unacceptable conditions were identified.

3.0 Summary of Operating Events

3.1 Unit 1

Unit 1 was manually scrammed from 21 percent power at 1:18 a.m. on December 18 due to increasing unidentified reactor coolant system (RCS) leakage inside the drywell. The unit had been operating at full power prior to the power reduction made in preparation for the shutdown. The unit reached Operational Condition 4 at 11:41 a.m. on December 18. Following completion of repairs to a packing leak on a Main Steam Line Drain Valve (1F016) the unit was started up and criticality was reached at 6:41 a.m. on December 23.

During the reactor startup on December 23, drywell leakage returned to the pre-shutdown levels and continued to increase. The unit was manually scrammed from 26 percent power at 12:03 a.m. on December 27 to facilitate another drywell entry. Following completion of repairs to a packing leak on the RCIC Inboard Steam Isolation Valve (1F007), the unit was started up and criticality was reached at 5:00 a.m. on December 29.

During the power ascension on December 29, drywell leakage increased more than 2 GPM over a 4 hour period, causing entry into LCO 3.4.2.3. However, troubleshooting determined the source to be a leaking reactor head vent line and cycling of the Reactor Head Vent Isolation Valve (1F002) significantly reduced the indicated leakage. The LCO was cleared and startup was continued. The unit reached full power on January 1, 1987. (Detail 3.3 further discusses the Unit 1 RCS leakage problems).

3.2 Unit 2

Unit 2 was manually scrammed from 17 percent power at 4:45 a.m. on December 12, 1986 in order to enter containment and repair a leaking Containment Instrument Gas (CIG) solenoid valve on the "B" Inboard Main Steam Isolation Valve (MSIV). The leaking solenoid valve was detected during surveillance testing on December 10, but attempts to reduce the CIG leakage by cycling the MSIV were unsuccessful. During the outage, repairs were completed on all of the MSIV's, and a bushing on the "C" phase main transformer was replaced. The unit started up and reached criticality at 5:16 p.m. on December 16. (See Detail 3.4).

3.3 Unit 1 Unidentified RCS Leakage in Drywell

Unit 1 was manually scrammed from 21 percent power at 1:18 a.m. on December 18 due to increasing unidentified reactor coolant system (RCS) leakage inside the drywell. The leak rate had been gradually increasing for several weeks and had reached 3.7 GPM at the time of the shutdown. The Technical Specification limit of 5.0 GPM had not been reached, but the licensee elected to shutdown to perform the necessary repairs. The unit reached Operational Condition 4 at 11:41 a.m. on December 18.

During the forced outage, drywell inspections identified a leak on a Main Steam Line Drain Valve (1F016) and the valve was repacked. The MSIV air solenoid valves were also reworked during the outage. (See Detail 3.4). Following completion of the maintenance, the unit was started up and criticality was achieved at 6:41 a.m. on December 23.

During the startup, unidentified drywell leakage returned to the pre-shutdown levels and continued to increase. The power ascension was halted at 65 percent power. Off-normal procedure ON-100-005, Excess Drywell Leakage Identification, was performed on December 26, and the RCIC Steam Supply Inboard Isolation Valve (1F007) was determined to be the major contributor to the drywell leakage. The unit was manually scrammed from 26 percent power at 12:03 a.m. on December 27 to facilitate a drywell entry to repair the RCIC valve. During the outage other drywell valves were visually inspected, and five other packing glands were tightened. After repairs were completed, the unit returned to criticality at 5:00 a.m. on December 29.

During the power ascension on December 29, unidentified RCS leakage again began to increase and LCO 3.4.3.2 was entered at 4:00 p.m. when measured leakage increased by more than 2 GPM over a four hour period. The 12:00 p.m. readings were 0.18 GPM and the 4:00 p.m. readings were 2.49 GPM. The startup was halted at approximately 10 percent power, and the licensee planned to shutdown the unit at 5:00 a.m. on December 30 to meet the Technical Specification LCO action statement. However, during performance of leakage identification procedure ON-100-005, at 4:00 a.m. on December 30, the licensee identified the source of the leakage as a reactor head vent line. The leakage was significantly reduced following cycling of the reactor vent head valve (1F002). Unidentified RCS leakage following cycling of the valve was 0.32 GPM, which is a typical leak rate during operation.

The licensee concluded that the reactor head vent valve (1F002) had not been fully closed during the startup, and that seat leakage existed in the 1F001 head vent valve, allowing a flow path from the reactor vessel head to the drywell equipment drain tank (DWEDT). This conclusion was supported by the fact that the DWEDT

temperatures had increased to approximately 210 degrees F during the startup and decreased to approximately 140 degrees F after the 1F002 valve was cycled. The head vent temperature alarm came in periodically during the startup. In addition, an alarm for the refueling bellows leak detection also came in, which is connected to the drain line to the DWEDT, and was probably caused by the steam in the line.

The LCO was cleared, and following review of the test data and leakage rate measurements, the licensee decided to continue startup to full power. The unit reached full power on January 1, 1987. Unidentified drywell leakage after reaching full power was less than 0.5 GPM.

3.4 Reactor Shutdown Due to CIG Leakage (Unit 2)

At approximately 6:00 a.m. on December 10, a leak in the Unit 2 Containment Instrument Gas (CIG) header was identified during the performance of surveillance test SO-284-001, Monthly Functional Test of MSIV Closure RPS Instruments. During stroking of the 'B' inboard MSIV (2F022B) to the 10 percent closed position, CIG pressure decreased significantly and following testing, both CIG compressors were required to operate in order to maintain system pressure. The lowest CIG pressure reached was 76 psig (90 psig header). Based on the test results, the licensee theorized that the 'B' MSIV test solenoid valve had developed an air leak.

On December 11, at 7:00 p.m. reactor power was reduced from 100 percent to 83 percent in order to perform troubleshooting on the suspected leaking MSIV air operator. After three attempts at cycling the valve to the 10 percent closed position with no noticeable reduction in the CIG leakage, the MSIV was fully closed. With leakage still unchanged, the valve was reopened, but a sharp decrease in CIG header pressure to 74 psig occurred, and the valve was immediately reclosed. Since reopening the MSIV had the potential of depressurizing the CIG header, the licensee decided to keep the MSIV shut and perform a manual shutdown to allow drywell entry for repairs. Reactor power was decreased to 17 percent and a manual scram was inserted at 4:54 a.m. on December 12.

Examination of the CIG solenoid valves during the forced outage revealed air leakage in two out of the four inboard MSIV's. The root cause of the failures was determined to be breakdown of the E. F. Houghton SAFE 620 lubricant used on the solenoid valve seals. The E. F. Houghton lubricant dried to a sticky substance, which inhibited movement of the air cylinder pistons in the three way valves. In addition, warehouse spares examined after the event identified that the lubricant had also dried out in those valves leaving a residue. Several of the spares leaked during bench testing. The lubricant previously used in the MSIV's was Parker Super-O-Lube, but the lubricant was changed to E. F. Houghton SAFE

620 because of deficiencies noted during Environmental Qualification Tests. Licensee discussions with the valve vendor following the event verified that the preferred lubricant was Parker Super-O-Lube. On December 19, 1986 the Automatic Valve Corporation issued a letter to NRC Region III to notify them of the potential problem with E. F. Houghton 620 lubricant since a similar installation was utilized at Quad Cities.

During environmental qualification testing of the MSIV solenoid manifolds by Wyle Laboratory in January 1985, the solenoid valves with Parker Super-O-Lube did not operate properly following the radiation testing. Data collected by Wyle indicated that when exposed to a radiation field of greater than 1 x 10E6 RAD, the Parker Super-O-Lube lubricant breaks down into an adhesive, powdery substance which could adhere to the moving parts of the actuator and restrict or prevent solenoid valve movement. The operation of the MSIV assembly is such that the solenoid valve directs air to the valve actuator to open the MSIV and vents air from the actuator to close the MSIV. The safety concern was that the lubricant breakdown may prevent the MSIV from closing when required. Based on this information, the seal lubricant was changed to E. F. Houghton SAFE 620 during the last refueling outages for both units. (See Inspection Report 50-387/85-36; 50-388/85-32).

A Nonconformance Report was written for each unit on the MSIV solenoid manifold for each unit on December 13. Although the three-way valve is only used for MSIV testing, and does not have a safety-related function, a similar failure was possible in the other solenoid valves. The valves were conditionally released for Operational Conditions 4 and 5 pending NPE evaluation of the acceptability of returning to Parker Super-O-Lube. Based on a letter from General Electric, dated December 13, the valves were conditionally released for Operational Condition 1 because Environmental Qualification test results were available to verify acceptability of the Parker lubricant. The NCR will remain open pending receipt of the GE test report and update of the EQ binder for the MSIV's.

All of the Unit 2 MSIV solenoid valves (24 assemblies) were reworked and properly relubricated using the Parker Super-O-Lube lubricant during the forced outage. During a Unit 1 forced outage, which started on December 18 (See Detail 3.3), all of the Unit 1 MSIV air operators were also reworked with the Parker Super-O-Lube lubricant. This item will remain unresolved pending further NRC review (387/86-27-01).

3.5 Failure to Meet 125-Volt DC Battery Technical Specification (Unit 2)

On December 19, 1986, Unit 1 was in Operational Condition 4 and Unit 2 was at approximately 75 percent power. At 10:30 p.m. on December 19, 1986, the Unit 1 1D613 battery charger (channel "A") failed. Since Unit 1 was in Operational Condition 4, the Unit 1 Technical Specifications did not require any action to be taken as long as the battery in the opposite division was operable, so an LCO was not entered. However, since common loads are normally supplied by the Unit 1 bus, the Unit 2 Technical Specifications require that the common loads be transferred to the associated Unit 2 battery bus if the Unit 1 bus cannot be restored to operable status. The control room operators did not enter the appropriate LCO on Unit 2. The appropriate LCO was not entered because of inadequate communication between the control room operators and an unclear Technical Specification LCO.

On December 20, 1986, an electrician performing repairs on battery charger 1D613 noted that the voltage on the Unit 1 125-Volt DC battery bus 1D610 had decreased to 116 volts. The bus is required by Technical Specifications to be greater than 129 volts. Although the battery voltage had decreased to 116 volts, the low voltage alarm setpoint for the bus was set for 110 volts and therefore did not annunciate. The electrician notified the control room and the shift supervisors determined that an LCO should have been entered at 10:30 p.m. on December 19, 1986 on Unit 2. An LCO was then entered per Technical Specification 3.8.2.1 and backdated to 10:30 p.m. December 19. The common loads were transferred to the Unit 2 battery bank, and the LCO on the battery bank was cleared. The battery charger was repaired on December 21, and the LCO on the battery charger was cleared at 9:00 p.m. on December 21.

Subsequent licensee review indicated that the Unit 1 battery had been discharged for about 17 hours. A calculation performed by the licensee indicated that the battery would have been able to supply its design basis load profile for about 2 hours starting at its as-found condition. The licensee and the inspector concluded that 2 hours was sufficient time to manually effect a transfer of loads to a Unit 2 battery if the need arose during a transient or accident. Therefore, the potential safety consequences of this event were not severe.

Technical Specification Limiting Condition for Operation 3.8.2.1 states that the Unit 1 125-Volt DC load group channel "A" full capacity charger, 1D613, is to be operable in Operational Condition 1. With one of the chargers inoperable, the associated battery bank is to be demonstrated to be operable within 1 hour, or the associated battery is to be declared inoperable. With one of the Unit 1 125-Volt DC load group battery banks inoperable, the inoperable bank is to be restored to operable status within 2 hours, or the common loads aligned to the

Unit 1 battery bank are to be transferred to the corresponding Unit 2 battery bank. Otherwise, the common loads aligned to the inoperable battery bank are to be declared inoperable. The common loads supplied by battery bank 1D610 include control power for the "A" diesel generator emergency service water, RHR service water, and control structure ventilation systems.

The Unit 1 and Unit 2 Technical Specifications were revised under Amendment No. 31 and 7, respectively, on February 8, 1985 to allow common 125-volt DC battery loads to be supported by either of the two unit batteries. Previously only the Unit 1 125-volt DC batteries were able to support these common loads. The licensee developed a common load transfer scheme which allowed common loads to be powered from a 125-volt DC source on either unit through the use of manual transfer switches. However, the Technical Specification revision resulted in the need for the action statements for both units to be reviewed in order to determine the action required when one battery bank is inoperable. For example, in this specific event, with the Unit 1 battery bank inoperable, the Unit 2 Technical Specification contained the appropriate action required. This requirement contributed to the failure to meet the Technical Specification.

The administrative controls for maintenance and surveillance on common systems has been a continuing concern of NRC Region I. During a Management Meeting in January 1986 prior to the Unit 1 Second Refueling Outage, the control of common systems was discussed. This event reemphasizes the fact that additional training on common systems may be appropriate. The inoperability of the Unit 1 battery charger 1D613 from 10:30 p.m. December 19 to 3:00 p.m. December 20, without performance of the applicable action statements is a violation of Technical Specification 3.8.2.1. (388/86-30-01)

3.6 Containment Radiation Monitor Valve Misalignment (Unit 1)

At 4:00 a.m. on December 3, 1986, the licensee identified that the in-service Unit 1 Containment Radiation Monitor (CRM) was not properly aligned to the drywell as required by Technical Specification 3.4.3.1. Further investigation found adequate sampling flow to the sample pumps although the manual isolation valves were isolated. The valve misalignment was found during performance of a realignment of the in-service CRM from the upper drywell to the suppression pool in order to vent the suppression pool through SBGT.

The Reactor Building Nuclear Plant Operator (NPO) was directed to open the suppression pool supply and return manual isolation valves and then to close the drywell supply and return manual isolation valves. The NPO reported to the control room that the return valve to the drywell was already closed. Further investigation determined that the lower drywell supply valve was open, instead of being closed as required. Therefore, the as-found valve alignment had the upper and lower drywell supply manual supply valves open, and the common return valve closed.

Further review of the misalignment determined that the as-found valve line up coincided with an unapproved, hand-drawn drawing for the CRM's being utilized by several operators. The drawing mistakenly interchanged the lower drywell supply valve (1-57-145) and the drywell return valve (1-57-147). This valve alignment on the unapproved drawing was not in accordance with the governing procedure, and did not allow a sample path for the CRM. The licensee collected all of the copies of the unapproved hand-drawings for the CRM's, and destroyed them. The drawings were being used by several operators to better understand some non-routine operations with the system required by several design problems (See Detail 4.2.1).

Subsequent investigation performed by the licensee at CRM panel 1C227A detected sample flow through the system with the manual isolation valves closed. The flow indicator was observed at 0.6 CFM. Normal flow with the appropriate sample valves open was 1.3 CFM. The low flow alarm actuates at 0.5 CFM, and thus was never reached to provide an alarm to the operators. In addition, the CRM design allows flow rates down to 0.5 CFM in order to provide a valid sample. Although the return valve was closed, vent holes in the sample pump provided the adequate flow path for the sampling system.

The licensee performed a valve lineup verification of the CRM's on both units and did not find any further discrepancies.

4.0 Licensee Reports

4.1 In-Office Review of Licensee Event Reports

The inspector reviewed LERs submitted to the NRC:RI office to verify that details of the event were clearly reported, including the accuracy of description of the cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were involved, and whether the event warranted onsite followup. The following LERs were reviewed:

Unit 1

86-037, Entry Into LCO 3.0.3 to Perform Surveillance Testing

*86-038, ESF Actuations Due to Personnel Error During Surveillance Testing

**86-039, Entry Into LCO 3.0.3 to Perform Nitrogen Addition

Unit 2

None this period.

*Previously discussed in Inspection Report 50-387/86-24; 50-388/86-26
**Further discussed in Detail 4.2.

4.2 Onsite Followup of Licensee Event Reports

For those LERs selected for onsite followup (denoted by asterisks in Detail 4.1), the inspector verified that the reporting requirements of 10 CFR 50.73 had been met, that appropriate corrective action had been taken, that the event was adequately reviewed by the licensee, and that continued operation of the facility was conducted in accordance with Technical Specification limits. The following findings relate to the LERs reviewed on site:

4.2.1 LER 86-039, Entry Into LCO 3.0.3 In Order to Perform Nitrogen Addition and Purging Operations on the Wetwell

On October 3, 1986, during the Unit 2 first refueling outage, a leakage quantification test performed on the Containment Atmosphere Monitoring System identified a leak at each CRM panel in excess of 100 liters per minute. The leakage was emanating from vent holes located on each CRM Vacuum Blower. The concern was that following an accident, primary containment atmosphere could leak into secondary containment if the containment isolation valves were opened after a primary containment isolation. (See Inspection Report 50-387/86-24; 50-388/86-26).

Prior to the implementation of a permanent design modification, interim actions taken to reduce the risk of this leakage should an accident occur, included the isolation of one division of the CRM system from the post-accident sampling lines penetrating containment while the second division of the CRM system is aligned to the drywell.

On December 1, 1986, the in-service containment monitoring division for Unit 2 had to be realigned to the suppression pool to support the addition of nitrogen. With one CRM isolated, and one aligned to the suppression pool, Technical Specification LCO 3.0.3 was entered since a CRM was not aligned to the drywell. Similar scenarios occurred on December 2, 3, and 11. The licensee decided to keep the standby division isolated to remain consistent with the safety evaluations written to justify continued operation. This decision is currently being reevaluated by the licensee.

Long term resolutions for the CRM blower leakage are being pursued by the licensee on a high priority basis to obviate the need to enter Technical Specification 3.0.3. The licensee's corrective actions are being followed under unresolved item 388/86-26-03.

4.3 Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted by the licensee were reviewed by the inspector. The reports were reviewed to determine that they included the required information; that test results and/or supporting information were consistent with design predictions and performance specifications; that planned corrective action was adequate for resolution of identified problems; and whether any information in the report should be classified as an abnormal occurrence.

The following periodic and special reports were reviewed:

-- Monthly Operating Report - November 1986, dated December 15, 1986.

The above report was found acceptable.

5.0 Monthly Surveillance and Maintenance Observations

5.1 Surveillance Activities

The inspector observed the performance of surveillance tests to determine that: the surveillance test procedure conformed to Technical Specification requirements; administrative approvals and tagouts were obtained before initiating the test; testing was accomplished by qualified personnel in accordance with an approved surveillance procedure; test instrumentation was calibrated; limiting conditions for operations were met; test data was accurate and complete; removal and restoration of the affected components was properly accomplished; test results met Technical Specification and procedural requirements; deficiencies noted were reviewed and appropriately resolved; and the surveillance was completed at the required frequency.

These observations included:

-- SO-024-001, Monthly Diesel Generator Operability Test, performed on the 'B' diesel generator on December 23, 1986.

During the performance of SO-024-001B on December 23, 1986, the inspector noted that the diesel generator field current display on the CRT display was not indicating an expected value. With the diesel generator fully loaded, the indicated field current was 4 amps, when it normally is 110 - 130 amps. Additionally, when the

operator made adjustments to the voltage controller, the indicated value did not change. The operator stated that the display was not operating properly, but was unaware of any problem.

The inspector discussed the problem with the responsible system engineer, and determined that the inputs to the field current indications had been previously disconnected by a bypass due to isolator circuit problems. Bypass 1-86-096 was issued on May 22, 1986 to isolate process computer points to the diesel generator. The engineer immediately wrote a Work Authorization to have the field current displays altered to show an indeterminate reading, so the readings would not be misinterpreted by the operators. The field current indication is typically not utilized by the operator during operation of the diesel generator. The inspector had no further questions.

6.0 Region I Temporary Inspection Instructions

6.1 RI-86-01: Inspection of Standby Gas Treatment System

Region I Temporary Inspection Instruction RI-86-01, Inspection of Standby Gas Treatment System, was issued September 22, 1986 to provide guidance for reviewing the operation and failure modes of the Standby Gas Treatment System (SGTS). The objective of the review was to verify that there were no unidentified design features which could render the SGTS susceptible to single failures.

During an engineering review of the SGTS at Pilgrim, a design deficiency was identified which rendered the system incapable of performing its design function in the event of a particular single failure. The identified deficiency involved the use of fail-open air-operated dampers in the cross-tie line on the outlet of the filter trains. Under accident conditions, with a loss of offsite power, motive air to the cross-tie damper would be unavailable. The failure of a single SGTS train charcoal bed temperature sensor would cause activation of the charcoal bed deluge spray system in one train, rendering it unable to remove radioactive iodine as designed. The affected train could not be isolated from the remaining train because of the failed open cross-tie damper. Approximately 25 percent of the system flow would be drawn through the ineffective charcoal bed and passed through the main stack, resulting in elevated release levels.

The inspector conducted a review of the FSAR, system drawings and schematics, operator lesson plans, and the event report history to verify that a failure mode and analysis had been properly performed, and that design discrepancies similar to Pilgrim were not present at Susquehanna.

FSAR Section 6.5.1 states that failure of any component of the filtration train, assuming loss of offsite power, cannot impair the ability of the system to perform its safety function. The power supplies to the SGTS equipment comes from the 4KV ESS Buses, and this ensures uninterrupted operation in the event of loss of normal AC power. The FSAR also includes a detailed failure mode and effects analysis for the system, which was reviewed for adequacy by NRR during the licensing process.

A similar problem cannot be experienced at Susquehanna since the system dampers are hydromotors powered by the 4KV emergency buses. Springs in the electro-hydraulic actuator provide the failure position upon loss of power. In addition, when the charcoal bed high temperature setpoint is reached, the cross-tie valves fail closed, and the train is automatically isolated.

7.0 Traversing Incore Probe (TIP) System Failures

During the current inspection period, two problems involving the TIP System occurred in Unit 1. On December 21, while performing the 18 Month TIP Explosive Valve Operability Test (SI-178-202), a small amount of smoke was seen rising from the control room TIP panel "D" when the charge was fired. The operators immediately reset the keylock switch thus stopping the flow of current through the circuit, restored the TIP system and verified proper circuit operation. Instrument and Control Technicians examined the circuitry and discovered no faults, but noted dust on some of the power resistors and assumed that the smoke resulted from dust burning off a power resistor.

While operating the TIP system on December 24, the "E" TIP machine was unable to fully withdraw the TIP detector into the shield. This would have prevented the isolation valve from closing in case of a containment isolation signal. The TIP was manually retracted and was deenergized which resulted in closing the isolation valve. The Technical Specification Section 3.6.3 was then cleared and the TIP mechanism tagged to prevent operation. I&C technicians determined that the problem was due to faulty limit switch contacts. The problem was corrected by moving the leads to spare contacts.

Two previous problems with TIP indexers in 1986 resulted in the licensee shutting down the affected unit. The first occurred on April 24, when during Unit 1 startup the "A" TIP indexer lodged in an intermediate position while running TIP traces for calibrating LPRMs. Since Technical Specification Action Statement 3.2.2 required power to be reduced below 25 percent of Rated Thermal Power (RTP), the licensee decided to shutdown the unit to allow containment entry and facilitate repairs.

The second shutdown occurred in Unit 2 on October 30, also during startup when problems were encountered with the "E" TIP indexer not allowing insertion of the TIP detector. The failure in Unit 1 prevented the TIP indexer from rotating from one of the channels, while the Unit 2 failure prevented insertion of the TIP detector into the channel. Both failures appear to have been caused by misalignment of the drive and locking CAMS as a result of containment heatup from cold shutdown to normal operating procedures.

Although several other previous problems with the TIP machines have occurred in addition to those mentioned, they did not result in unit shutdown. The licensee is evaluating the replacement of the TIP indexers with a new model from General Electric which they hope will result in fewer failures.

8.0 Exit Meeting

On January 13, 1987 the inspector discussed the findings of this inspection with station management. Based on NRC Region I review of this report and discussions held with licensee representatives, it was determined that this report does not contain information subject to 10 CFR 2.790 restrictions.