U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-387/84-22
50-388/84-28

Docket Nos. 50-387 (CAT C)
50-388 (CAT B2)

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: June 9 - July 15, 1984

Inspectors: Ebe McCabe, for 7/23/84
R. H. Jacobs, Senior Resident Inspector date

Ebe McCabe, for 7/23/84
L. R. Plisco, Resident Inspector date

Approved by: Ebe McCabe 7/23/84
Ebe C. McCabe, Chief Reactor Projects Section 1C, DPRP date

Inspection Summary:
Areas Inspected: Routine resident inspection (U-1 128 hours, U-2 107 hours) of plant operations, equipment readiness, licensee events, open items, surveillances, startup testing, and control of temporary modifications.

Results: Unit 2 has completed the heatup phase and Test Condition 1 of the startup program (Detail 6.0). Control of temporary modifications (bypasses) is satisfactory (Detail 7.0). Unit 2 remote shutdown panel was tested satisfactorily, but the associated emergency procedure requires corrections (Detail 6.2.2).

Two violations were identified: two chemistry grab samples required by a Technical Specification Action statement were missed (Detail 4.2.2) and fire detection instrumentation surveillances were not performed within the Technical Specification time limits (Detail 5.2).

DETAILS

1.0 Followup on Previous Inspection Items

1.1 (Closed) Inspector Followup Item (387/83-15-01): Loss of Startup Transformer (T-10) with resultant Reactor Scram

On June 24, 1983, Unit 1 scrammed as a result of a main turbine trip on high reactor vessel water level. The transient was caused by an insulation failure in the 'C' phase of startup transformer T-10. The transformer was subsequently replaced with a spare transformer. On September 7 - 9, 1983 the licensee replaced Startup Transformer T-10 with the repaired transformer. On November 2, 1983 the licensee submitted to NRC Region I a report on the failure of the transformer which included a Transient Analysis Report and a damage report for the transformer. The failure of the Federal-Pacific transformer was caused by a dielectric breakdown in the 'C' phase winding insulation. The licensee's investigation did not uncover any abnormalities in the design, manufacturing or operation of the transformer. The event was also reported in LER 83-092. The reports were reviewed by region-based specialists and found acceptable. The transformer replacement was observed by the resident inspector and documented in Inspection Report 50-387/83-21.

1.2 (Closed) Licensee Identified Item (387/82-40-07): Ammonia Stress Corrosion Cracking of Emergency Diesel GeneratorIntercoolers

On November 16, 1982, the licensee issued a 10 CFR 21 report concerning ammonia stress corrosion cracking of the emergency diesel generator intercoolers. The intercoolers were fabricated by McQuary-Perfex, Inc. The condition of the tubing was discovered during failure analyses performed on intercoolers submitted to the vendor for retubing. The cooler tubes were specified to be admiralty brass, but it was determined that some tubes were actually aluminum-brass. Although aluminum-brass appeared to be more susceptible to failure, both alloys experienced stress corrosion cracking. The licensee believes the ammonia was generated by the decay of organic material in anerobic parts of the spray pond.

The licensee replaced the brass tubing in the intercoolers with 90/10 Cu/Ni under Plant Modification Record (PMR) 82-642, on January 31, 1983. The 90/10 Cu/Ni has a much greater resistance to ammonia stress corrosion cracking and is also used for heat exchanger tubing in the remainder of the jacket water system. The coolers were leak tested and functionally tested after installation. The inspector reviewed the completed PMR package and the associated work authorizations. The inspector observed portions of the intercooler replacement as documented in Inspection Report 50-387/82-40. The diesel generator jacket water systems were drained, flushed, and refilled with fresh corrosion inhibitor containing a biocide to help minimize the ammonia generation by bacteria.

The inspector had no further questions on this matter.

1.3 (Closed) Violation (387/82-32-04): Inoperable Ionization Fire Detectors

On October 14, 1982, the licensee determined that Fire Zone 1-7B did not have any ionization fire detectors although two were required by Technical Specifications. On October 15, 1982 it was determined that surveillances were not performed on heat detectors in Fire Zone 0-27E. Both of these occurrences were a violation of Technical Specification 3.3.7.9. The licensee submitted their response to the violation on December 23, 1982 (PLA-1451). Immediate licensee corrective action included establishing an hourly fire watch in Fire Zone 1-7B to compensate for the lack of ionization detectors and performing the appropriate surveillances for the heat detectors in Fire Zone 0-27E.

On November 2, 1983, Amendment No. 17 to the Unit 1 license was issued which deleted Fire Zone 1-7B from Technical Specification Table 3.3.7.9-1, since there is no equipment required for safe shutdown in Zone 1-7B. The heat detectors in Zone 0-27E were subsequently included in surveillance procedure SI-113-201 which assures that they will be tested on a routine basis.

On November 12, 1982, in Revision 2 to LER 82-003, (a related fire protection detector event) the licensee provided a listing of other inconsistencies found in their review. In an effort to determine and rectify inconsistencies concerning the fire detection system, PP&L reviewed as-built conditions, the Fire Protection Review Report (FPRR), and the Technical Specifications. These discrepancies were also corrected in Amendment No. 17 to the Unit 1 license and verified by the inspector. (See Detail 1.4).

The inspector reviewed the revised surveillance procedure SI-113-201, Semi-Annual Functional Check of CO2 System Fire Protection System Heat Detectors and verified that it now includes Fire Zone 0-27E. The completed Work Authorization (WA-T27128) that performed the initial surveillances on October 15, 1982 and the most recent surveillance, performed on March 4, 1984 were also reviewed and found acceptable.

1.4 (Closed) Inspector Followup Item (387/82-32-05): Discrepancies with Technical Specifications

On October 15, 1982, the licensee performed a field inspection of fire protection detector locations in conjunction with designated fire zones and room numbers. Several fire zones were found to be inconsistent with Technical Specification Table 3.3.7.9-1. Due to administrative errors, the licensee was unable to correlate detector locations with the appropriate fire zones and room numbers.

On November 2, 1983, Amendment No. 17 to the Unit 1 license was issued. It included changes to Technical Specification Table 3.3.7.9-1. The amendment corrected the administrative errors, decreased the number of detectors in two fire zones, and added fire zones that warranted inclusion in the Technical Specifications to reflect as-built conditions.

1.5 (Closed) Inspector Followup Item (387/80-30-02; 388/80-18-02) Erosion Control of Western Edge of Site Boundary

This item referred to erosion stabilization of the western lay-down area and was re-reviewed in Inspection Report 387/82-25; 388/82-11. PP&L had initially committed to stabilizing these areas in 1981. Portions of the area have been stabilized, but the licensee has decided to keep the remainder of the area open because of additional site construction and additional requirements for disposal of site wastes. The licensee has indicated that this action conforms with appropriate permit requirements and since the state, not the NRC, has jurisdiction over non-radiological environmental matters, further NRC involvement is not required.

1.6 (Closed) Inspector Followup Item (387/83-1 -06) Secondary Containment Bypass Leakage

In April 1983, the licensee reported that a potential bypass leakage path existed from secondary containment via the feedwater lines following a Design Basis LOCA. This had not been previously included in offsite dose calculations. This issue was reviewed in Inspection Report 387/83-12. Construction Deficiency Report (CDR) 388/83-00-03 addressed the same issue on Unit 2. This CDR was reviewed in Inspection Report 388/84-08. It was determined that bypass leakage of less than 3.8 SCF per hour would not invalidate the FSAR offsite radiological effects analysis. Local leak rate test results on Units 1 and 2 feedwater lines demonstrated that bypass leak rates were less than 3.8 SCF per hour. By letter dated May 4, 1984, the licensee submitted proposed amendments for Units 1 and 2 Technical Specifications to reflect bypass leakage limits on the feedwater lines and to require periodic pneumatic local leak rate testing.

1.7 (Closed) Inspector Followup Item (387/83-14-02) Control of Bypasses

During the period May 24 - June 7, 1983, Unit 1 was operated with the reactor vessel high level trip of the main turbine bypassed, in violation of Technical Specifications. This event was reviewed in Special Inspection Report 50-387/83-14. An associated concern was that no technical specification reference was made on the bypass form or the Bypass Log to indicate that a Technical Specification LCO was involved, since the bypass was installed when the plant was in Operational Condition in which the LCO did not apply. Additionally, Administrative Directive AD-QA-307 was imprecise with respect to when a bypass form was required during active troubleshooting of a system.

The inspector reviewed AD-QA-307, Electrical and Mechanical Bypass Control, Revision 4, dated October 23, 1983, the Bypass Log, and AD-QA-302, System Status and Equipment Control, Revision 1 dated June 17, 1983. AD-QA-307, Section 6.1.2 has been revised to permit using a bypass without issuing a Bypass Form only when the bypass is used during active troubleshooting and is removed prior to the individual leaving the work area; or when a bypass is associated with, recorded on, and removed during the performance of an approved procedure.

The inspector also verified that the Bypass Log Sheet has been revised to require indicating when an LCO is involved and the affected Operational Condition. A review of the Bypass Log revealed no discrepancies with respect to Technical Specification related bypasses. Other findings from this review are discussed in Detail 7.0.

Other actions taken by the licensee in response to this occurrence involved revision of AD-QA-302, to specify that the system status file (where bypass forms are kept) be reviewed prior to declaring a system operable or changing Operational Conditions.

1.8 (Closed) Inspector Followup Item (387/83-06-05) Reactor Vessel Loose Parts and (Closed) Inspector Followup Item (387/83-25-03) Steam Dryer Crack

On March 10, 1983, the licensee reported that the Unit 1 Loose Parts Monitoring System (LPMS) was indicating a loose part in the steam dryer section of the reactor vessel. The noise was not evident until power levels exceeded 65% rated power, and changed character at approximately 95% power. The noise was detected on sensor channel 2, the main steam outlet line at the 108 degree azimuth, and channel 4, the feedwater inlet at the 90 degree azimuth.

During the scheduled outage that commenced on April 4, 1983 the licensee removed the reactor head, steam dryer and steam separator in an attempt to locate the noise source. Visual inspections and underwater television camera inspections of the vessel internals were conducted, with no evidence of loose parts. Various parts of the reactor vessel and internals were impacted to determine if any of the impacts could be acoustically matched to the noise signal generated during plant operation, but no significant information was obtained. The general conclusion of the inspection and impact testing indicated that there were no loose parts and that the noise was generated by the reactor internals.

After the startup from the outage on May 30, 1983, the LPMS again picked up the noise when reactor power reached 95%. The licensee then concluded that the noise levels encountered were normal background levels and increased the LPMS alarm setpoints in June 1983 to reduce the number of nuisance alarms, and allow more effective use of the system.

On December 9, 1983, upon removal of the Unit 1 steam dryer from the reactor vessel for the tie-in outage, the licensee discovered a four foot long crack in a vertical weld in the upper part of the shroud. The crack was within five feet of the triangulated location of the loose part noise previously investigated. Weld repairs were performed on the crack on January 11, 1984 restoring the dryer integrity and reinforcing the joint. (See Inspection Report 387/83-29).

The conclusion was made that during the initial dryer inspection the crack was in its incipient stages and could only be revealed by its characteristic noise when excited by full steam flow across the dryer. After eight months of commercial operation the crack was clearly visible due to continuous deformation caused by increasing steam flow through the crack. A complete analysis of all permanent and temporary detector inputs was conducted at full power when the unit restarted in February 1984 and the result was that the noise no longer existed.

The inspector reviewed the associated safety evaluations and setpoint change requests and found them acceptable. The inspector questioned the technical staff engineer concerning the current setpoints since the background level has changed since the dryer crack repair. He stated that the setpoints have not yet been returned to a lower value, but would be reset in the near future. However, the alarm setpoints currently meet the regulatory guide sensitivity recommendations, as justified by vendor calculations.

2.0 Review of Plant Operations

2.1 Operational Safety Verification

The inspector toured the control room area 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 were reviewed. Nuclear instrument panels and other reactor protective 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, badging, and availability of radiation monitoring equipment.

The inspector reviewed shift supervisor, plant control operator, and nuclear plant operator logs covering the entire inspection period. Sampling reviews were made of tagging requests, night orders, the bypass log, incident reports, and QA nonconformance reports. The inspector also observed several shift turnovers during the period.

On June 24, 1984, on Unit 2, the licensee was performing a quarterly calibration of the 'A' ADS timer (SI-383-322). This surveillance caused the 'A' ADS Out of Service annunciator to alarm. Since HPCI was also out of service, the inspector questioned whether the licensee was entering Technical Specification LCO 3.0.3 which applies if both ADS and HPCI are out of service. The inspector was informed that ADS was considered operable. The inspector reviewed the procedure and discussed this with cognizant I&C personnel who verified that, during the surveillance, a jumper is installed which would prevent operation of the 'A' ADS solenoid valves, should the actuation logic be satisfied. The procedure contained no precautions concerning the applicability of Technical Specification LCOs. The inspector and shift personnel reviewed Technical Specification Table 3.3.3-1 Section 4, Automatic Depressurization System, which requires a minimum of 1 ADS timer channel per trip system to be operable. Note (a) on this table indicates the following:

"A channel may be placed in an inoperable status for up to 2 hours for required surveillance without placing the trip system in the tripped condition provided at least one OPERABLE channel in the same trip system is monitoring that parameter".

Since there is only one ADS timer per trip system, the inspector concluded that Note (a) did not apply and hence, the licensee must take action required by ACTION 31 which requires declaring the associated ECCS inoperable. If ADS is considered inoperable, the licensee, per Technical Specification 3.5.1.d.2, is required to be in Hot Shutdown within 12 hours (even if HPCI is operable) and if HPCI and ADS are both inoperable, the licensee must, per Technical Specification 3.0.3, take action within 1 hour to place the unit in an Operating Condition in which the specification (i.e. ADS and HPCI inoperability) does not apply. To summarize, the Technical Specification, as written, does not permit conducting surveillance testing of the ADS timer (and certain other ADS instrumentation) without entering a Technical Specification LCO which leads to a plant shutdown. In this occurrence, the jumper was only installed for a period of approximately 20 minutes, and hence the licensee did not exceed any Technical Specification limits.

In response to the inspector's concerns, the licensee quickly restored the 'A' ADS solenoids to operable status and elected not to proceed with the next part of the test which involved calibrating the 'B' ADS timer until the Technical Specification issue was resolved. The inspector discussed this issue with the NRR project manager and individuals from the Standard Technical Specification section and I&C

section in NRR. This concern with ADS instrumentation is a recently discovered generic problem and NRR had reviewed this issue and determined that an acceptable revision to the Technical Specification would be as follows:

With an ADS trip system inoperable, restore the ADS trip system to operable status:

1. Within 7 days, provided HPCI and RCIC are operable, or

2. Within 72 hours, if either HPCI or RCIC is inoperable.

   Otherwise, be in Hot Shutdown within the next 12 hours and less than 100 psig within the following 24 hours.

The licensee has initiated action to request a Technical Specification revision similar to the above and issued a temporary change to the surveillance procedure to require declaring ADS inoperable while the jumper is installed. The licensee's actions will be reviewed in a subsequent inspection. (387/84-22-01; 388/84-28-01)

2.2 Station Tours

The inspector toured accessible areas of the plant including the control room, relay rooms, switchgear rooms, penetration areas, reactor and turbine buildings, radwaste building, ESSW pumphouse, Circulating Water Pumphouse, Security Control Center, diesel generator building, plant perimeter and containment. 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

On June 13, 1984, a lightning strike on the 230KV Montour-Mountain Transmission line caused the loss of Unit 1 Startup Transformer T-10 and resulted in a reactor scram. The loss of T-10 caused the feedwater controllers to lockup at 100% flow, lockup of the 'A' recirculation pump, and a runback of the 'B' recirculation pump. These actions resulted in a reactor vessel level increase and a main turbine trip at +54 inches. T-10 was returned to service and the unit returned to operation on June 14. (See Detail 3.3.1).

On July 3, 1984, a lightning strike on the Montour-Mountain line caused the loss of T-10 and resulted in a reactor scram. The transient was similar to the one on June 13, but during this event the operators attempted to take manual control of the feedwater pumps, were unable to control level, and the unit tripped on reactor vessel low level. (See Detail 3.3.2)

During the forced outage a modification was installed to provide an uninterruptible power supply (UPS) to portions of the recirculation control circuit and repairs were completed to a drywell/suppression pool vacuum breaker. On July 8, at 2:29 p.m. the reactor reached criticality and was synchronized to the grid on July 9. The unit reached 100% rated power on July 12.

During the period, the licensee frequently operated the Emergency Service Water and RHR Service Water systems with the spray pond networks in service in order to cool down the spray pond. Technical Specifications require that the spray pond be maintained at less than 81 degrees F. The licensee has submitted a proposed license amendment to raise the minimum temperature to 88 degrees F.

3.2 Unit 2

On June 11, 1984, at 1:35 p.m. criticality was achieved following a two week outage during which repairs were completed on the 'B' loop LPCI injection valve and No. 1 main turbine bypass valve. At 8:30 p.m. the Unit was shutdown due to dual indication received on a suppression pool vacuum breaker during a surveillance. An entry was made into the suppression pool and repairs were completed on the vacuum breaker limit switch. (See Detail 4.2.4)

On June 12, at 2:45 p.m. the reactor reached criticality and continued the heatup phase of the startup test program.

On June 15, while performing RCIC surveillance testing, problems were encountered with the turbine lube oil system and RCIC was declared inoperable. Troubleshooting determined that the lube oil system flow distribution was not adjusted properly and oil level in the turbine coupling bearing sightglass slowly decreased until it was below the sightglass approximately 30 minutes into the test. The lube oil system drain piping was replaced with larger diameter piping (one and one-half inches), with concurrence of the vendor, and subsequent testing was satisfactory. RCIC was declared operable on June 24.

On June 24, while performing HPCI surveillance and startup testing, it was determined that water was in the HPCI lube oil system. The oil was replaced on June 26. The startup testing for HPCI was performed successfully on June 27. This completed the low power testing program. NRR issued the full power license on June 27, and the plant entered Test Condition I on June 28.

On July 5, ST 28.1, Shutdown and Cooldown Demonstration from the Remote Shutdown Panel, was performed successfully. The reactor was scrammed manually at 20% rated power from the control room for the test. (See Detail 6.2.2). On July 6, at 2:55 p.m., the reactor reached criticality and was synchronized to the grid on July 8 and the plant entered Test Condition 2.

3.3 Reactor Scrams due to Loss of T-10 (Unit 1)

3.3.1 Reactor Scram of June 13, 1984

On June 13, 1984, at 5:20 p.m. a lightning strike on the 230KV Montour-Mountain off-site power transmission line caused a loss of the Unit 1 Startup Transformer (T-10). During the transfer of power to the Unit 2 Startup Transformer (T-20), a number of the plant electrical buses lost power. Division I containment isolations and a half-scram were received when the normal power to the Reactor Protection System (RPS) "A" Motor Generator was momentarily lost. A main turbine trip followed on reactor vessel high level. This resulted in a reactor scram and recirculation pump trip. The Standby Gas Treatment System (SGTS) and Control Room Emergency Outside Air Supply System (CREOASS) also auto-started due to the Division I isolation signal. On the subsequent level decrease due to the turbine trip, RCIC auto-started at -30 inches and maintained reactor level. No ECCS actuations occurred. The "A" Emergency Diesel Generator (EDG) auto-started but did not load onto the bus. The operators carried out the emergency procedures for the scram, using RCIC, and then feedwater, to control reactor vessel level and pressure. The T-10 transformer was returned to service at 6:32 p.m. the same day. Unit 1 had been operating at 100% power in Operational Condition 1 prior to the event.

The loss of T-10 also resulted in a Division 1 containment isolation, feedwater controller failure and a half-scram on Unit 2, which was at approximately 2% power, but the unit remained in operation.

On Unit 1, review of the transient determined that the loss of T-10 interrupted voltage to non-ESS control panel 1Y218 which provides power to the feedwater control circuitry and the "A" Recirculation Pump Control Circuitry. The momentary undervoltage to the feedwater control system during the bus transfers locked up the feedwater pumps at 100% feed flow. The momentary undervoltage also affected the reactor water level instrumentation in the feedwater control system, resulting in a recirculation pump runback signal to minimum speed from the recirculation flow limiter No. 1 circuit.

The "A" recirculation pump did not runback since the loss of power to its control circuit caused the recirculation pump motor-generator to lock up at its pretransient speed. The "B" recirculation pump ran back since its control power was still available. With steam flow decreasing due to the "B" recirculation pump runback, and feedwater flow remaining constant at 100%, reactor vessel water level increased until it reached the level 8 trip setpoint (+54 inches). This tripped the main turbine and feedwater pump turbines. The resultant turbine control valve fast closure initiated a full reactor scram.

The licensee completed their review of the transient and verified that all systems operated as designed with the exception of the Unit 2 alternate supply breaker to bus 2A201. The alternate breaker took an abnormally long time to close (approximately 8 seconds) which caused the "A" diesel generator to start on undervoltage to its associated bus. The alternate breaker closed before the diesel generator loaded on the bus. The licensee declared the breaker inoperable and investigated the cause. The breaker was inspected and no discrepancies were identified. It was retested satisfactorily and declared operable. A special test was conducted on June 28, to verify that the breaker would operate properly on a loss of power to the bus, and was performed successfully.

The inspector reviewed the sequence of events printout, computer recorder traces, operator logs and plant drawings to ascertain that the plant responded as designed during the transient. The sequence of events printout did not provide any useful information due to a power loss during the event.

Based on the evaluation of plant data and discussions of the event with licensee personnel, the plant responded properly and corrective actions taken prior to the resumption of facility operation were adequate. The inspector also confirmed that the licensee made the proper ENS notification of the event as required by 10 CFR 50.72.

Unit 1 returned to operation on June 14, 1984 after a Plant Operations Review Committee (PORC) review of the transient.

An identical transient had previously occurred on June 24, 1983 due to a failure of the T-10 transformer. (See Inspection Report 50-387/83-15 and LER 83-092). The inspector discussed the sequence of events for both transients with the licensee and determined that, if both units had been operating at 100% power prior to the event, both would have tripped due to the loss of one off-site power supply. The licensee is studying the plant's response to the event and is investigating possible modifications to prevent recurrence. Detailed reviews are being conducted by the plant staff and NPE, and the Nuclear Safety Assessment Group (NSAG) is assessing the incident.

3.3.2 Reactor Scram of July 3, 1984

On July 3, 1984, at 2:12 p.m., with Unit 1 at 100% power and Unit 2 at 15% power, off-site power from T-10 was interrupted due to a lightning strike. Both units received a half-scram signal from the resulting loss of RPS buses. During the subsequent automatic bus transfers, Unit 1 experienced speed control signal lock-ups on two of the three feedwater pumps and the "A" recirculation pump. The "B" recirculation pump experienced a runback causing a reactor vessel level transient. The "A" feedwater pump unexplainedly tripped. Because of the similar transient on June 13, (See Detail 3.3.1), the operators quickly took manual control of the feedwater pumps but were unable to control level and prevent a reactor scram on low reactor vessel level (+13 inches). The scram caused level to reach the low-low level setpoint (-38 inches), initiating HPCI and RCIC vessel injections, closing the MSIV's, and tripping the recirculation pumps. The plant was stabilized using HPCI and RCIC for level and pressure control. One safety/relief valve lifted during the transient. Unit 2 did not scram during the event due to its low power level. Unit 1 was brought to cold shutdown.

During the outage the licensee installed a power supply modification to the recirculation pump control circuity and repaired a drywell/suppression pool vacuum breaker that failed to cycle properly during a surveillance after the transient. Troubleshooting of the "A" reactor feedwater pump did not identify a cause for the trip.

Unit 1 returned to operation on July 8. During the startup extensive testing was conducted on the feedwater pumps, but no problems were identified. The licensee has not ruled out the possibility that the "A" feedwater pump was inadvertently tripped when the operators took manual control. The modification installed on Unit 1 consisted of providing an uninterruptable power supply (UPS) to portions of the recirculation pump control system to prevent a runback of the "B" recirculation pump upon the loss of T-10, thus minimizing the level transient. The feedwater pumps and the "A" recirculation pump will still lock-up at the pre-transient speed on the loss of control power.

The inspector reviewed the sequence of events printout, computer recorder traces, operator logs and plant drawings to ascertain that the plant responded as designed during the transient. Based on the evaluation of plant data and discussions with licensee personnel, the plant responded properly with the exception of the "A" reactor feed pump. Corrective actions and post-trip review taken prior to the resumption of facility operation were acceptable.

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 the 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

*84-025/00, Two Main Turbine Surv [illegible] nces Not Completed within Technical Specification time limit

*84-026/00, Core Spray Valve Isolation Signal not per Technical Specifications

*84-027/00, Two Chemistry Grab Samples required by Technical Specification Action Statement not taken within required time limits

Unit 2

84-005/00, Inadvertent Isolation of Reactor Water Cleanup (RWCU) valve

**84-006/00, Reactor Shutdown due to inoperability of the 'B' loop of Low Pressure Core Injection

84-007/00, Technical Specification Action Statement not met concerning RWCU Containment Isolation valves During Surveillance Testing

**84-008/00, RPS Manual Scram Due to Stuck Open Turbine Bypass Valve During Shutdown

*84-009/00, Unit Shutdown to Repair Faulty Vacuum Breaker Indication

* Further discussed in Section 4.2.
** Previously discussed in Inspection Report 50-387/84-18; 50-388/84-22.

4.2 Onsite Followup of Licensee Event Reports

4.2.1 LER 84-025, Main Turbine Surveillances not completed within Technical Specification time limits (Unit 1)

This LER documents the late performance of two weekly surveillance tests on the main turbine bypass system. The tests are normally performed on the Sunday night shift and should have been completed on April 29, 1984. Because of a power reduction for demineralizer changeout, the tests had to be postponed. It was not discovered that the tests were late until 11:00 p.m. April 30. The 25% interval beyond 7 days expired at 9:18 and 9:28 p.m. respectively on April 30 for these tests. The appropriate limiting conditions for operations were entered and the tests completed at 1:18 and 1:03 a.m. respectively on May 1. Hence, the appropriate action was taken about 2 hours after the surveillance interval expired. The inspector reviewed the Operations Surveillance Log, a memorandum dated May 10, 1984 to the Shift Supervisor from the Day Shift Supervisor, and discussed the occurrence with Operations personnel.

The cause of the occurrence appears to be shift supervision not checking the Surveillance Log for outstanding surveillances on a sufficient frequency. Additionally, it has not been standard practice to highlight, on the surveillance log, the time at which surveillances violate the Technical Specification interval when a surveillance cannot be completed during its normal schedule. Shift supervision has been directed to review this log on a shiftly basis.

This occurrence was found and reported by the licensee and, based on a review of LERs over the past year, this is the first occurrence of a missed surveillance test under the cognizance of operations. Therefore, no notice of violation will be issued. However, late performance of surveillance tests due to personnel errors within a work group is a recurring problem. No one specific work group has been at fault and the number of missed surveillances is relatively small when compared to the total surveillances performed. Nevertheless, this aspect of the surveillance program needs increased emphasis.

4.2.2 LER 84-027 Two Missed Chemistry Samples (Unit 1)

This LER documents an occurrence on May 23, 1984. Two chemistry surveillances, required to be obtained on a once-per-eight hour basis, were not performed within the required frequency. These samples were required by Technical Specifications (TS) because the Unit 1 Turbine Building Stack Particulate Iodine and Noble Gas (SPING) monitor and the Unit 2 'A' RHR Service Water radiation monitor were inoperable.

Specifically, the Unit 1 Turbine Building SPING was removed from service at 7:40 a.m. on May 22 at which time continuous sampling was commenced for particulate and iodine via auxiliary equipment, and once-per-eight hour grab sampling for noble gas was begun. At 2:57 a.m. on May 23, 1984, the Unit 2 'A' RHR Service Water (RHRSW) system was placed in service and, since the associated radiation monitor was inoperable. eight hour grab sampling was begun with the first sample taken at 5:35 a.m. on May 23. When the day shift chemistry technician (Level II) relieved the night shift at 7:00 a.m. on May 23, he reviewed the LCO log which indicated that the next SPING sample was due at 7:45 a.m. and the next Unit 2 RHRSW sample was due at 11:00 a.m. The technician neglected to take the samples until 11:40 a.m., when he took the SPING sample 4 hours late. He did not obtain the RHRSW sample. At about 5:00 p.m., when the swing shift technician relieved the day shift, he observed, by review of the LCO log, that the Unit 1 SPING sample was taken late and the RHRSW sample was not taken during day shift. The swing shift technician then obtained both samples, both of which showed no detectable activity, and informed management of the late samples. The elapsed time between samples was 13 hours for the RHRSW and 12 hours for the SPING sample. The Technical Specification required frequency for these samples is 8 hours plus 25%, or 10 hours.

The inspector discussed this occurrence with the Chemistry Supervisor and foremen and examined the controls established to ensure samples are taken within their required frequency. When Operations enters a Limiting Condition for Operation that affects Chemistry, Operations informs Chemistry and assigns a log sheet to Chemistry for the purpose of recording the required samples. The chemistry technician enters this sheet into their LCO log and records in the Chemistry Log that an LCO has been entered. Each technician reviews the LCO log upon assuming responsibility for the shift and is responsible for obtaining the required samples and recording them in the LCO log. Normally, on day shift, the chemistry foreman makes up assignment sheets for chemistry personnel which provide each individual's assigned tasks for that day. The foreman typically includes the LCO required samples on the sheet for the technician who assumed the shift responsibility, although it had been previouisly emphasized to the technicians that they are responsible for samples required for LCO requirements. On May 23, the normal foreman was absent and the daily assignment sheets were provided by a different chemistry foreman. The assignment sheets were made up using a tickler file and samples to meet LCO requirements were not included on the shift technician's assignment sheet. Apparently, the RHRSW and SPING samples were missed because the technician relied upon his assignment sheet to delineate his required duties for that day. Missed chemistry samples has been a recurring problem. This occurrence is a violation of Technical Specification surveillance requirements. (387/84-22-02)

The licensee's corrective actions included administrative changes to improve the LCO log and tickler file. The Chemistry Supervisor also reviewed the occurrence and discussed technician responsibilities with all Level II Technicians. The inspector interviewed two Level II Technicians and found they understood their responsibilities with respect to sampling to meet LCO requirements. Both indicated that sampling to meet LCO requirements was the highest priority on their shift.

4.2.3 <u>LER 84-026, Core Spray Valve Isolation Signal not per Technical Specifications (Unit 1)</u>

This LER documents that the isolation signals to the Core Spray Full Flow Test valves are not as specified in Technical Specification 3.6.3-1 and FSAR Table 6.2-12. The Technical Specification and FSAR require Core Spray Full Flow Test Isolation Valves HV-152F015A, HV-152F015B (Unit 1) and HV-252F-015A, HV-252F015B (Unit 2) to isolate on low reactor vessel level or high drywell pressure. The as-built condition currently isolates the valves on low reactor vessel level or high drywell pressure with a low reactor pressure permissive signal. The isolation signal nonconformance was identified by licensee personnel during a Technical Specification review on May 16, 1984.

Administrative control was immediately placed on the full flow test valves by tagging the valves closed and deenergizing the valves in the closed position to prevent the opening of the valves. Plant Modification Requests (PMR) 84-3085 and 84-3086 were issued to modify the isolation logic. The modification involves removing the low reactor pressure permissive from the isolation circuit.

The discrepancy between the Technical Specification and as-built condition concerning the isolation signals will not affect the safe operation of the Core Spray System since the valve is normally closed except for testing purposes. The Core Spray System operability was not affected.

The completion of the modification will be reviewed in a subsequent inspection. (387/84-22-03; 388/84-28-02).

4.2.4 LER 84-009, Suppression Chamber Vacuum Breaker Dual Indication (Unit 2)

The LER documents that Unit 2 was shutdown in anticipation of an unscheduled drywell entry to repair a faulty vacuum breaker position indication. On June 11, 1984 dual position indication (open and closed) was received from one outboard suppression chamber-drywell vacuum breaker during the performance of a regularily scheduled 31-day operability check of the ten vacuum breakers. The unit was at less than 5% rated power. The appropriate LCO was entered and the inboard vacuum breaker was verified closed. The reactor was then shutdown to perform a suppression chamber entry to repair the vacuum breaker.

The vacuum breaker was found fully closed, and the position indication limit switch was repaired by adjusting the switch actuating bolts. The operability check was reperformed successfully. The LCO was cleared and the unit returned to operation on June 12, 1984.

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 the report 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 - May 1984

-- Monthly Operating Report - June 1984

The above reports were found acceptable.

5.0 Monthly Surveillance and Maintenance Observation

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-252-002, HPCI Flow Verification, performed on June 27, 1984.

-- SO-250-002, RCIC Flow Verification, performed on July 3, 1984.

On July 3, 1984 the inspector observed the performance of Unit 2 surveillance procedure SO-250-002, Revision 1, RCIC Flow Verification, dated May 4, 1984. The test was performed to verify that the RCIC system would properly quick start and pump rated flow from the Condensate Storage Tank (CST) to the CST at rated pressure. The test was performed for post-maintenance due to the replacement of the turbine governor hydraulic actuator (EGR).

On the test witnessed July 3, 1984 the turbine tripped on electrical overspeed on two separate attempts. In both cases turbine speed peaked above 5000 RPM. The electrical overspeed was set at 5037 RPM. It was determined that the new EGR was not responding properly.

The original EGR was reinstalled and the system was successfully tested on July 4, 1984, and declared operable.

5.2 Fire Detection Instrumentation Surveillances

The inspector performed a review of Fire Detection Instrumentation surveillance procedures and records to verify that the associated Technical Specification surveillance requirements had been met and that Technical Specification 3.3.7.9, Fire Detection Instrumentation, reflected the "as-built" condition for both Units 1 and 2. A comparison was made between the Fire Protection Review Report, Unit 1 and Unit 2 Technical Specifications, surveillance procedures, and licensee drawings.

A similar review was previously conducted by the licensee based on findings reported in LER 82-003, and resulted in Amendment No. 17 to the Unit 1 operating license. (See Sections 1.3 and 1.4). Since the issuance of the Unit 2 Technical Specifications, the licensee had identified additional discrepancies between the two units. Corrections to these inconsistencies were included in proposed licensee amendment No. 43.

The following items were identified during the inspectors review:

-- The Unit 2 Technical Specifications were inconsistent with the Unit 1 Technical Specifications concerning the number of detectors, or the minimum required detectors, in several common fire zones. For example Unit 1 Technical Specifications require a total of nine ionization detectors in fire zone 0-26H (Control Room Above Ceiling). Unit 2 Technical Specifications require only a total of six detectors for the same zone. A review of surveillances and drawings verified that nine detectors are actually installed. Similar inconsistencies were found for fire zones 0-27B and 0-27C. The Unit 2 Technical Specifications require correction to accurately reflect the as-built plant. The inspector informed the licensee of the discrepancies, and they initiated action to amend the Unit 2 Technical Specifications. This item is unresolved pending review of the submittal of the proposed license amendment. (388/84-28-03)

-- Surveillance Procedure SI-013-208, Revision 0, contains acceptance criteria that are not consistent with the Unit 2 Technical Specifications. The surveillance procedure states that the acceptance criteria for ionization detectors in fire zone 0-26H (Control Room Under Floor Unit 2) is seven operable detectors. The Unit 2 Technical Specifications require a minimum of eight detectors for the same area.

The inspector discussed the item with the licensee who stated that the surveillance procedure would be changed to correctly reflect the Unit 2 Technical Specification.

-- Several Technical Specification surveillance requirements were violated due to inadequate procedures or improper implementation of the surveillance program.

Unit 1 and Unit 2 Technical Specification Surveillance Requirement 4.3.7.9.1 states that each of the required fire detection instruments which are accessible during unit operation shall be demonstrated operable at least once per six months by performance of a channel functional test.

Unit 1 Technical Specification Table 3.3.7.9-1 requires a total of six photoelectric detectors in fire zone 1-4G (Main Steam Piping). Review of the associated surveillance procedure SI-113-210, Revision 0, found that only four were actually tested. The other two detectors were inadvertently omitted from the procedure.

Unit 1 Technical Specifications require a minimum of seven operable ionization detectors in fire zone 0-26H (Control Room Under Floor Unit 2). The inspector reviewed the associated surveillance tests performed to meet the requirement and determined that as of July 5, 1984 the last semi-annual functional test was completed on September 23, 1983. The surveillance procedure, SI-013-208 provides the testing requirements for ionization detectors in eleven different fire zones. On March 30, 1984, two additional fire zones were tested (which had been recently added to Technical Specifications), and were entered into the surveillance tracking system as meeting the requirements of SI-013-208, but none of the other eleven zones, including 0-26H, were tested. Therefore, when the surveillance became due in April 1984, the work group reviewed the surveillance status printout and it indicated the surveillance was already performed on March 30, 1984, and it was not performed.

The failure to perform the required surveillance testing at least once per six months on the fire detection instrumentation in twelve fire zones (i.e. 0-26H and 1-4G) is a violation of Technical Specification surveillance requirement 4.3.7.9.1. (387/84-22-04) The licensee performed the semi-annual functional test of the ionization detectors on July 6, 1984.

6.0 Startup Test Program (Unit 2)

The inspector witnessed portions of selected tests to verify that:

-- Procedures with appropriate revision were available and used;

-- Test changes were identified and implemented without changing the basic objectives of the test, in accordance with station procedures and Technical Specifications;

-- Prerequisites were completed and verified;

-- Initial conditions were met;

-- Special test equipment required by the procedures was utilized and calibrated;

-- Test was performed in accordance with the procedure;

-- Results were satisfactory and met the acceptance criteria;

-- Test exceptions or deviations were identified, documented and reviewed.

6.1 Heatup Phase Test Witnessing

6.1.1 HF-200-085 Local Criticality Data Acquisition Test

On June 10, 1984, the inspector witnessed Hot Functional Test, Revision 0, Local Criticality Data Acquisition Test. The test involved taking the reactor locally critical by withdrawal of up to five diagonally adjacent control rods in an "X" pattern. The purpose of the test was to obtain rod reactivity worth data to benchmark core simulation methods.

Prior to the test, the inspector reviewed the test procedure, the 10 CFR 50.59 safety evaluation generated by Nuclear Plant Engineering and local criticality test predictions. The inspector also discussed safeguards used to prevent inserting excessive reactivity with licensee reactor engineering and startup test personnel, and with cognizant Region I and NRR startup program personnel. Safeguards included in the test were: 1) removing the RPS shorting links so that any single neutron monitoring system scram signal (including Source Range Monitor/SRM) would cause a reactor trip, 2) performing the test with peripheral rods located near an SRM, 3) programming Rod Worth Minimizer (RWM) so that only the rods required for the test could be withdrawn, 4) withdrawing control rods in a manner which minimizes control rod notch worth (i.e. using a rod "pumping" technique), and 5) performing 1/m plots to enable prediction of criticality.

No problems were encountered with the test. The inspector observed one of four local criticalities achieved. Criticality was achieved within approximately 4 notches of the rod worth calculations, and the actual configuration at which criticality was achieved was accurately predicted by the 1/m plot.

6.1.2 ST 15.1 HPCI Condensate Storage Tank Injections

On June 27, 1984, the inspector witnessed Startup Test ST 15.1, Revision 2, Condensate Storage Tank Injection. The test was performed at rated reactor pressure and with reactor power level sufficient to provide steam for the HPCI turbine without a decrease in reactor pressure. One Turbine Bypass Valve (BPV) was open to approximately 37% prior to HPCI operation.

The test consisted of a manual start and automatic initiation with the HPCI pump taking suction from and discharging to the Condensate Storage Tank (CST). During the manual start, the HPCI turbine was started by opening the turbine steam supply valve and turbine speed was gradually increased until HPCI pump flow was 5000 GPM. The pump discharge valve was then throttled to obtain a pump discharge pressure approximately 100 psig above reactor vessel pressure to simulate vessel injection conditions. System stability was demonstrated by demanding step changes with the HPCI flow controller in both the manual and automatic modes.

During the automatic initiation portion, the system was started using the manual initiation pushbutton and the flow controller in the automatic mode maintaining flow equal to 5000 GPM. The turbine was to be operated for two hours after the automatic start to demonstrate continuous operation of the system at equilibrium conditions, but was shutdown after one hour and fifteen minutes due to suppression pool temperature limitations. A Test Exception Report (TER) was issued since the two hour run was not completed. The TER resolution was "use-as-is" since the FSAR states that the test is to be run for up to two hours or until steady turbine and pump conditions are reached or until limits on plant operation are encountered. Steady state turbine and pump conditions had been reached, and suppression pool temperatures were approaching the Technical Specification limits.

Following completion of the test, a review of the test data indicated that the required HPCI pump net positive suction head (NPSH) of greater than 21 feet was not achieved. The calculated NPSH was actually 19 feet. A TER was issued and investigation determined that the booster pump suction startup strainer, used during the preoperational testing program, had not been removed. It was removed on June 28, 1984. The strainer was consciously left in the system after the preoperational test program, since full system flow had not been achieved during initial testing, but was not removed after full flow testing was completed. The licensee is investigating the cause and the inspector will followup upon review of the forthcoming LER. On July 7 ST 15.1 was performed at a reactor pressure of 150 psig, and indicated that the NPSH deficiency was corrected by removal of the strainer. A formal retest to close the TER is planned for Test Condition 2.

Several other tests were performed in conjunction with this test. Hot functional test HF-252-081, Revision 0, HPCI Minimum Flow Valve Operability Verification was performed to verify the automatic operation features of the HPCI minimum flow valve at rated reactor pressure. It was performed satisfactorily.

6.2 Test Condition 1 Testing

6.2.1 ST 22.3 EHC Pressure Regulator Test

On June 29, 1984, the inspector witnessed ST 22.3, EHC Pressure Regulator test. This startup test consisted of inserting approximately 10 psi negative and positive step changes in the pressure regulator setpoint and verifying that the EHC system maintained plant pressure at the new setpoint in a controlled manner. Another part of the test involved failing the operating pressure regulator and verifying that the alternate pressure regulator controlled pressure at its setpoint (3 psig lower than the operating pressure regulator). This test will be repeated at each test condition. In Test Condition 1, the test was performed with the Turbine Bypass valves controlling pressure. Reactor power was approximately 14%. No problems were encountered during performance of the test.

6.2.2 ST 28.1 Shutdown and Cooldown Demonstration

On July 5, 1984, the inspector witnessed 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 of the control room. Initial plant conditions had the plant at 20% rated power with a normal electrical system lineup. The operators manually scrammed the reactor and closed the MSIV's from the control room, and then evacuated to the remote shutdown panel. Using the remote shutdown panel control devices, reactor pressure, temperature and level were stabilized, and then a slow cooldown was conducted using RCIC, safety-relief valves, and the Shutdown Cooling Mode of the RHR system. Also, the adequacy of the Emergency Operating Procedures were demonstrated. The test was completed when reactor pressure had been decreased to less than 98 psig and the RHR Shutdown Cooling mode had been placed into operation.

The following items were noted during the test and procedure review:

-- Numerous indication problems were encountered during the test. At least six indicating lights did not operate properly. Examples included ESW pump B&D indicating lights and the RCIC steam supply outboard valve HV-2F008 position indication. The majority were due to faulty light bulbs and were corrected prior to the completion of the test. The remainder had work authorizations issued to correct them.

-- The instrumentation transfer switch needed for division II suppression pool temperature indication (TI-25752) was not labeled and not listed in either the emergency operating procedure EO-200-009, Revision 1, Plant Shutdown From Outside the Control Room, or the operating procedure OP-200-001, Revision 1, Remote Shutdown - Normal Plant Operating Lineup. The operators determined the use of the switch late in the test. The other division of suppression pool temperature indication was available during the test.

-- The emergency operating procedure EO-200-009 and the normal operating procedure OP-200-001 were inconsistent concerning certain initial switch positions. EO-200-009 states that the RCIC vacuum tank condensate pump normal position is "STOP", but OP-200-001 states that the normal position is "AUTO". EO-200-009 also states that RHR head spray supply valve HV-25112 should be open, but OP-200-001 states that the valve should be closed. These inconsistencies temporarily confused the operators at the remote shutdown panel, but were resolved after discussion.

-- The component identification for several valves did not match the identification for the component in the emergency procedure. For example, EO-200-009 identified valve HV-2F062 as "RCIC TURB EXH OUTBD VAC BREAK" and the nameplate was "VAC RELIEF LINE CONT ISO OUTBD". Other examples were HV-2F084 and HV-2F010A.

-- The instrumentation nameplates at the remote shutdown panel (2C201) are attached to a coverplate that is opened out of the way to provide access to the RCIC flow controller, thus the nameplates are not visible when the panel is in use. This deficiency, along with poor unit indication on the instruments, caused some confusion for the operators initially at the panel and placing RCIC into operation.

-- EO-200-009 incorrectly states that the breaker for RHR valve HV-2F007A is at breaker 031 at MCC 2B229. The breaker is actually at MCC 2B219, and was identified properly by the operators performing the test.

-- The section of EO-200-009 which describes flushing the RHR piping to Radwaste prior to placing the RHR loop in service is incomplete in that several valve operations required were not included in the procedure. After a long delay and review of the system drawing, the operators correctly identified the problem and continued with the flush.

-- When placing the "A" loop of RHR in shutdown cooling mode, the emergency procedure EO-200-009 states that the "A" recirculation pump suction valve (HV-2F023A) is to be closed from the remote shutdown panel. It was determined by the operators during the test that the switch on panel 2C201 was actually for the "B" recirculation pump suction valve (HV-2F023B). This appears to be a design deficiency in the panel. A test exception was issued since the valve had to be operated from the control room during the test. Later it was demonstrated that the valve could be operated from outside the control room at the local breaker panel. The licensee is investigating long term fixes for the deficiency.

The co rection of the deficiencies in procedure EO-200-009 and the component identifications will be reviewed in a subsequent inspection. (388/83-28-04)

7.0 Temporary Modifications (Bypasses)

The inspector performed a review of the licensee's program for controlling temporary modifications or bypasses (i.e. jumpers, lifted leads, etc.) to determine that:

-- sufficient controls are applied to ensure that bypasses are correctly installed and removed;

-- a program exists to periodically review active bypasses;

-- bypasses are evaluated in accordance with 10 CFR 50.59 to determine if they involve an unreviewed safety question;

-- formal records to account for active bypasses are maintained and reviewed to determine the impact on system operability;

The inspector reviewed AD-QA-307, "Electrical and Mechanical Bypass Control", Revision 4, the Bypass Log, and various reviews of outstanding bypasses. In addition, the inspector checked several active bypass forms to verify the licensee's conclusions regarding applicability to Technical Specifications and verified that bypass tags were in place on the equipment.

The inspectors review indicated that the licensee is satisfactorily controlling the use of bypasses. No discrepancies were found with Technical Specification related bypasses. The inspector checked several bypasses to ensure tags on equipment were in place and legible and all were satisfactory. The following discrepancies were found during the review:

-- Bypass 2-84-067 issued July 2, 1984, which bypasses the Unit 2 control room annunciator window for the Turbine Generator Bearing High Vibration alarm, was issued without placing a bypass sticker on the annunciator window. Placing stickers on annunciator windows is required by a recent change to AD-QA-307. This discrepancy has been corrected.

-- No monthly review of the Unit 1 Bypass Log was apparently performed for the month of March 1984. Reviews were performed on all other months in 1984,

-- In general, the only work group providing written response to the Operations Log Review is the Technical Staff.

-- As of June 1984, eleven bypasses were greater than 180 days old and had not been dispositioned. Most of these bypasses were the responsibility of Radwaste.

-- Section Head approval of bypasses is required by procedure, but no space on the Bypass Form is provided for his signature. However, all Bypass Forms checked by the inspector contained the Section Head's signature, either in the margin or adjacent to another signature.

Licensee actions to correct these discrepancies will be reviewed in a subsequent inspection. (387/84-22-05)

8.0 Exit Interview

At periodic intervals during the course of this inspection, meetings were held with senior facility management to discuss inspection scope and findings.