U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-387/86-11; 50-388/86-11

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: May 28, 1986 - July 15, 1986

Inspectors: L. R. Plisco, Senior Resident Inspector

L. Doerflein, Project Engineer

Approved By: Jack Strosnider 7/28/86

J. Strosnider, Chief, Reactor Projects Section 1B, DRP — date

Inspection Summary:

Areas Inspected: Routine resident inspection (U1 - 87 hours; U2 - 153 hours) of plant operations, licensee events, IE Bulletin and Information Notice follow-up, ESW pump repairs, allegation followup, open item followup, Containment Integrated Leak Rate Test, surveillance, and maintenance.

Results: All ECCS systems were technically inoperable on Unit 2 while shutdown (Detail 3.3); IST relief was granted to repair the Unit 2 RCIC discharge valve (Detail 3.5); Unit 2 HPCI failed the quarterly full flow test due to a failed poppet valve (Detail 5.1); Inspections of Limitorque MOV's identified discrepancies (Detail 6.2); Interim Repairs to the ESW pumps were completed (Detail 7.0); and the "as found" CILRT was failed on Unit 2 (Detail 8.0). No violations were identified.

DETAILS

1.0 Followup on Previous Inspection Items

1.1 (Closed) IE Bulletin 81-01: Surveillance of Mechanical Snubbers

A region-based inspector specialist has evaluated the licensee's responses and has determined that they are technically adequate and satisfy the IE Bulletin action requirements. Verification has been made by the resident inspector that the licensee's responses were enacted.

1.2 (Closed) Unresolved Item (387/82-16-02): Correct ILRT Results for Control Rod Drive (CRD) System Headers Not Vented and Safety Analysis of CRD Line Breaks

The inspector noted that the licensee has evaluated the effects of CRD system leakage. Based on this evaluation, the licensee modified the CRD hydraulic system (as discussed in Inspection Report 50-387/85-18) to prevent backflow into the turbine building. The licensee also established acceptance criteria, based on a small fraction of 10 CFR 100 limits, for CRD leakage into the reactor building.

The licensee has implemented procedure TP-259-004, "Measurement of CRD Header Leakage", to determine the leak rate from the CRD headers with the reactor pressure vessel at accident pressure. The test is performed after the Integrated Leak Rate Test (ILRT) and the results are included in the final ILRT report. The inspector reviewed the data for the test performed on June 11, 1986 and noted that the measured CRD header leakage was well within the acceptance criteria. The inspector had no further questions.

1.3 (Open) Deviation (388/84-34-03): Compliance With Regulatory Guide 1.47

In July 1984, NRC inspector review identified that commitments in FSAR Section 3.13.3 regarding Regulatory Guide 1.47, "Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems" were not satisfied. The Regulatory Guide requires automatic indication in the control room for each deliberately induced inoperable status that renders safety systems or their auxiliaries unable to perform their safety function, if this occurs more frequently than once per year.

The licensee was performing monthly surveillance test SM-104(204)-009 (010, 011, 012), "Monthly 4KV Degraded Voltage Channel Functional Check" on all Unit 1 and 2 ESS busses. The surveillance opened states links which disabled the emergency diesel generator (EDG) loss of offsite power automatic starts, and automatic indication was not provided in the control room.

In response to the Deviation, the licensee stated in letter PLA-2389, dated January 17, 1985, that Plant Modification Requests (PMR) 84-3113 for Unit 1 and 84-3114 for Unit 2 would include design changes which would permit surveillance testing of the degraded grid voltage protection relaying without disabling the automatic 4KV bus transfer to alternate power sources on loss of power. In later correspondence, PLA-2419 dated March 7, 1985, the licensee stated that the modifications were planned for installation during the Unit 1 second refueling outage and the Unit 2 first refueling outage. Several of the corrective actions were previously reviewed in Inspection Report 388/85-10.

PMR 84-3113 was installed in April 1986 during the Unit 1 second refueling outage. During review of LER 86-019 (See Detail 4.2.1) the inspector found that although the modification is operational, the licensee has continued to utilize the previous surveillance test method, which is not in compliance with Regulatory Guide 1.47. The inspector discussed this discrepancy with the responsible electrical maintenance engineer and Technical Staff engineer and found that the procedure was in the process of being revised, but had not been implemented. The delay was because a timely decision had not been made to determine who was responsible for performing the new surveillance test. Since the test involved movement of a switchgear panel switch, the electrical maintenance technician could not perform the test. The operations section was reluctant to be responsible for the test since they could not correct any problems identified during the surveillance.

The applicable surveillance procedures have not been revised, and the Unit 2 modification remains to be completed. This item remains open.

1.4 <u>(Closed) Unresolved Item (388/84-34-07): Diesel Generator Procedural Controls</u> and,

<u>(Closed) Unresolved Item (388/84-34-04): Overvoltage Trips of Emergency Diesel Generators During Manual Starts</u>

During the Unit 2 Loss of AC Power event in July 1984, two emergency diesel generators (EDG) tripped on overvoltage when manually started. Review of the EDG overvoltage trips also disclosed two other occurrences (LER's 82-050 and 83-004) of EDG trips on overvoltage.

The licensee has replaced the frequency sensitive overvoltage relays and 1 second time delay timers with non-frequency sensitive relays with a five second timer. The modifications were performed in PMR 84-3105. This modification should prevent overvoltage trips due to slow starts or voltage overshoot. The inspector reviewed the Operational Readiness Form for the modification which was completed on May 14, 1986.

1.5 <u>(Closed) Unresolved Item (388/84-34-23): Labeling of Blackout Instrumentation</u>

Emergency Operating Procedure EO-200-030, Unit 2 Response to Station Blackout, was revised to include the RCIC turbine speed instrument number in the table of key instrumentation available (DC powered) during station blackout. In addition, the label for the instrument has been changed to purple to identify it as a DC powered indicator.

The inspector reviewed the revised procedure and verified the installation of the correct label.

1.6 <u>(Closed) Unresolved Item (387/85-35-01): Technical Justification For Omission of Vendor Recommendations for 18-Month EDG Inspections</u>

In December 1985, the inspector conducted a review of selected emergency diesel generator (EDG) surveillance procedures and identified that several maintenance inspection items recommended by the vendor, Cooper-Bessemer, were not included in the 18-month EDG Inspection procedure. The licensee was requested to demonstrate that the omission of the vendor's recommendations were justified and concurred with by the EDG vendor.

In response to the finding, the licensee discussed the omitted recommendations with the vendor on April 15, 1986 to determine if the inspection items were necessary or applicable. Several of the items recommended in the vendor manual were determined to be unnecessary because of other checks or instrumentation, or to be not applicable to Susquehanna's installation. In addition, several of the items were found to require excessive disassembly for the 72 hour LCO period. The remainder of the omitted items were included in the revised inspection procedure, SM-024-002.

The inspector reviewed the revised procedure and the vendor telephone call notes and found that the necessary changes had been completed and sufficient Technical Justification had been provided.

1.7 <u>(Closed) Inspector Followup Item (387/85-35-02; 388/85-31-01): Discrepancies With the 18-Month EDG Surveillance Procedures</u>

A review of 18-month emergency diesel generator (EDG) surveillance procedures in December 1985 identified several procedural and Technical Specification discrepancies. In response to the finding the licensee revised surveillance procedures SE-124-A02 (B02, C02 and D02) to add the required acceptance criteria and the applicable verification signoffs. In addition, the acceptance criteria were revised in procedures SE-124-107 (207) to delete an incorrect Technical Specification reference.

Proposed Amendment 80 for the Unit 1 Technical Specifications was submitted on February 10, 1986. This proposed change corrected the inconsistencies between the Unit 1 and Unit 2 Technical Specifications concerning the acceptance criteria for voltage and frequency during specific surveillance tests.

Surveillance procedures SE-124-107/207 are currently being revised to verify the actuation of the non-emergency trip relays during the emergency run. The previous test method only verified that the diesel did not trip.

The inspector reviewed the revised procedures, procedure change approval forms, and the proposed Technical Specification change submittal and had no further concerns.

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 entire 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, 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

Following completion of the ESW pump repair outage (See Detail 7.0), which commenced on May 24, Unit 1 was started up on June 14. During the main turbine warmup, a loud noise was heard from the 'A' low pressure turbine, and the unit was shutdown from 17 percent power on June 15 to investigate. The loud noise was thought to be caused by a loose baffle plate (heat shield) inside the turbine hood, which was repaired. Just prior to the shutdown an operator also noted that the 'B' recirculation pump seal pressures had equalized, indicating a failed seal. During the forced outage, the seal was replaced. The unit was restarted and reached criticality at 1:30 p.m. on June 19. The LP turbine noise continued, but it was determined to be a casing steam leak noise, and dispositioned as acceptable for operation until the next outage.

3.2 Unit 2

During the ESW pump repair outage, a Containment Integrated Leak Rate Test (CILRT) was performed. (See Detail 8.0). Following the outage, Unit 2 was started up and criticality was reached on June 18, 1986. During power ascension, the HPCI turbine failed the quarterly flow verification. (See Detail 5.1). The turbine was repaired and placed back in service on June 30. On July 2, the RCIC pump discharge valve was found failed in the closed position. The valve was repaired and the system declared operable on July 15 (See Detail 3.5).

3.3 Inoperability of All ECCS Systems While Shutdown (Unit 2)

On June 12, while in Operational Condition 4, an operator discovered that all low pressure ECCS Systems were technically inoperable due to a series of equipment releases for maintenance work. Reconstruction of the work released found that all ECCS systems had been inoperable from 11:15 a.m. until 8:40 p.m. on June 12. In addition, the Standby Gas Treatment System (SGTS) had also been inoperable at 12:20 p.m. the same day. Licensee evaluation of the event, which was independently verified by the inspector, found that no Technical Specification LCO violations occurred. Although the operators were unaware of all the LCO's that they had entered, the systems were restored prior to the action statement being violated.

At 8:20 a.m. on June 12, Equipment Release Form (ERF) A-51508 was released to allow work on reactor vessel water level indicating switch LISH-B21-2N031D. This level switch provides ECCS initiation signals to the Division II Core Spray and RHR logic. The ERF, however, did not identify that the 'B' loop of LPCI was affected. An LCO was only entered for the 'B' Core Spray loop. Technical Specification LCO 3.3.3 states that with one or more ECCS actuation channels inoperable, place the inoperable trip system in the tripped condition within 1 hour, or declare the associated ECCS inoperable.

At 10:50 a.m., ERF A-53440 was released to replace the pump start relays (62AX2A) for the 'A' and 'C' ESW pumps. With these pumps inoperable, the 'A' loop of Core Spray and the 'A' and 'D' RHR pumps were considered inoperable. This LCO was properly entered into the LCO log.

At 11:15 a.m., ERF A-53968 was released to allow work on the 'A' RHR loop LPCI injection valve (HV-E11-2FC015A) in order to perform a limitorque wiring inspection. This made the 'A' loop of RHR inoperable, but the LCO was not entered because the operators still considered the 'B' RHR loop operable.

The ERF concerning the LPCI injection valve was correctly processed, but due to the method of maintaining the LCO log book, an LCO was not entered. It was clear that the valve work made the 'A' RHR loop inoperable, but since the LCO log is only used for documenting LCO's for the current operational condition, an LCO was not recorded. The Unit was in Operational Condition 4, and only two subsystems of RHR and/or Core Spray are required by Technical Specifications. Since the operators were not aware of the 'B' loop of RHR being inoperable, it did not appear that an LCO had been entered for Condition 4.

In summary, at 11:15 a.m. LCO's should have been entered for all of the low pressure ECCS systems, but the control room operators thought that the 'B' RHR loop and the 'C' RHR pump in the 'A' RHR loop were operable. Technical Specification LCO 3.5.2 states that with no ECCS systems operable in Operational Condition 4, one subsystem should be restored within four hours, or secondary containment is to be established within the next eight hours. At 12:20 p.m., ERF A-54445 was released to inspect SGTS flow element FE-07551, which made both SGTS fans inoperable. Therefore, secondary containment integrity could not be established.

At 7:30 p.m., an operator was reviewing the equipment release forms and determined that only the 'B' RHR pump was operable for ECCS, so the appropriate LCO was entered. Further review found that the 'B' RHR loop had been affected by the level switch work, and at 8:40 p.m. it was recognized that no ECCS systems were operable. The operator immediately placed a hold on the work involving the 'A' RHR loop injection valve, and the equipment was restored. The work on the valve had not commenced. At 9:10 p.m. the level switch was returned to service, thereby restoring the 'B' loop of Core Spray and the 'B' LPCI loop to operable status.

Although all of the ECCS systems were technically inoperable, based on the Technical Specification action statements, the 'B' Core Spray loop and the 'B' RHR pump were actually functional in the ECCS mode, as long as a single failure of the other Division II level channel did not occur. Three out of the four level channels remained operable. In addition, the 'B' RHR pump was operating in the Shutdown Cooling mode throughout this occurrence, and could have been manually realigned if necessary.

Administrative procedures AD-QA-302, System Status and Equipment Control, and AD-QA-306, System/Equipment Release, establish the licensee's system for controlling the release of systems, equipment or components. An Equipment Release Form (ERF) is required whenever a safety related or Technical Specification system is required to be out of service. The work group requesting a system out of service completes the form and includes the technical specification section that is applicable and a brief description of the action item. The work group submits its list of items to be worked to Unit Coordination, where the schedules and plans are developed. The scheduling is needed to assure that Technical Specifications are properly considered. Unit Coordination verifies the indicated Technical Specification and makes any necessary corrections. The ERF is then delivered to Shift Supervision after Unit Coordination review. Upon receipt Shift Supervision also verifies the indicated Technical Specification and makes changes accordingly. Once all of the reviews are complete, and if the system can be released, Unit supervision releases the equipment. If an LCO is to be entered, this is entered in the LCO log book, and the system status file is updated.

During this event it appears that several portions of the equipment release program were not properly implemented. First, the level switch ERF was not forwarded to Unit Coordination from the work group, so Unit Coordination did not review the impact of the work, or verify the affected Technical Specification sections. Secondly, Shift supervision did not identify the full impact of the work during their review, and the correct LCO was not entered in the LCO log book. Thirdly, the full impact of the work was not included in the ERF submitted by the work group.

The licensee initiated a Significant Operating Occurrence Report (SOOR 2-86-079) to investigate the event and to determine the cause for not correctly entering the applicable LCO's when the equipment was released. In addition, the Nuclear Safety Assessment Group is

evaluating the cause of the event. The results of the licensee investigations will be reviewed in a subsequent inspection (388/86-11-01).

3.4 Scram Discharge Volume Vent and Valve Failure (Unit 2)

At 4:20 a.m. on June 11, during the performance of test procedure TP-259-004, Measurement of CRD Header Leakage, the 'A' scram discharge volume vent and drain valves did not reopen after a manual scram signal was reset. The manual scram had been inserted at 3:40 a.m. to perform a leakage rate test of the CRD headers with the RPV at accident pressure. Subsequent investigation found that the SDV vent and drain valve pilot valve (SV-2F009A) was venting air through the exhaust port, thereby preventing the air header to pressurize. The valve was replaced and examination of the failed valve identified that a piece of teflon tape used to seal the pipe ends had become caught in the seat of the exhaust valve. This pipe had been replaced as part of a modification installed during the outage. Similar occurrences have been documented with these valves. In December 1984 a piece of pipe dope was found in one of the valves, preventing its operation (Inspection Report 50-387/84-38; 50-388/84-47). In this case the valves could not be closed. Because of the concern of loose particles in the CRD air system, the licensee performed a freon flush of the system during the Unit 1 first refueling outage. In addition, the red brass piping in which pipe dope was used was cleaned. Other air tubing was replaced.

Both units now have redundant vent and drain valves and pilot valves, so the likelihood of the vent and drain lines failing has been significantly reduced. In addition, the valves are cycled quarterly during periodic surveillance testing to verify operability.

3.5 RCIC Pump Discharge Valve Failure

On July 2, 1986 the Unit 2 RCIC pump discharge valve (HV-249-F013) was found to be failed in the closed position. The valve was being stroked for a maintenance investigation, and the valve breaker tripped after taking the handswitch to the open position. The problem with the valve was originally identified during the RCIC Quarterly Valve Exercising surveillance test, SO-0250-003, which was performed on June 18, 1986. A work authorization was generated to investigate the problem. The valve was stroked again on July 1, and it was found to draw high current during the valve cycling. On July 2, the valve failed to stroke, and the breaker tripped. The breaker was reset, and RCIC was declared inoperable at 3:15 p.m. Unit 2 was at 86 percent power and in coastdown at the time of the event.

Technical Specification LCO 3.7.3 states that with the RCIC system inoperable, operation may continue for up to 14 days, provided the HPCI system is operable, or the unit is to be placed in Hot Shutdown. Subsequent attempts to open the valve were unsuccessful, and because of the LCO, the unit was going to be required to shutdown on July 16. The licensee had considered performing corrective maintenance on the valve operator, but valve operator maintenance would require a local leak rate (LLRT) post-maintenance test. The LLRT could only be performed with the unit shutdown.

Since the first refueling outage was scheduled for August 2, the licensee held discussions with NRR and Region I to determine if relief of the LLRT requirements could be granted until the start of the outage to prevent shutting down the unit. The alternative was to not perform maintenance on the valve, keeping RCIC inoperable. In this case, the unit would be required to shutdown, unless an emergency Technical Specification Change could be granted to extend the 14 day shutdown requirement. It was decided that it would be more prudent to attempt to return RCIC to service, and resolve the containment isolation function question by an alternate test method until the commencement of the outage.

The licensee submitted a Pump and Valve Inservice Test (IST) Program Relief Request to NRR on July 11, 1986 (PLA-2681). The letter requested a one time relief from performing a LLRT on 2F013 as required by the existing IST program. The licensee proposed an alternate leak test to be performed to quantify water leakage from a defined system test boundary. The test was performed prior to and following completion of the valve maintenance. The test was designed to allow a qualitative assessment of the leakage from that boundary. The leakage was not to be correlated to an air test. The normal LLRT air test will be performed during the refueling outage.

The inspector observed the performance of test procedure TP-250-009, RCIC Discharge Line Leakage Test, on July 11, 1986. This was the pre-maintenance leakage test. The test consisted of pressurizing the piping upstream of the 2F013 valve to the feedwater system pressure to determine the leakage through the other RCIC boundary valves. Then the pressure was increased to approximately 50 psig above feedwater pressure. The difference between the two readings correlated to seat leakage across the 2F013 valve. Three sets of data were taken during the test. Although the total leakage rate decreased during the three tests, the low and high pressure difference was essentially zero in all three measurements. The decreasing measurements were attributed to seating of other boundary valves due to the high pressure.

The corrective maintenance on the valve was performed on July 12 - 13, 1986. The torque switch and operator motor were replaced. Following the maintenance, a MOVATS test was performed and the valve was stroke timed. TP-250-009 was performed again and the leakage across the 2F013 valve was found to be 0.036 gpm. The stroke timing test was utilized to satisfy the valve operability requirements for the RCIC system initiation function and the MOVATS and TP-250-009 tests functionally and qualitatively satisfied the containment isolation function of the valve. Based on these results, the RCIC system was declared operable on July 15. The results of the LLRT will be reviewed in a subsequent inspection (388/86-11-02).

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

*86-019, Entry Into LCO 3.0.3 to Perform Surveillance Testing

86-020, ESF Actuation (CREOASS) Due to Improper Jumper Installation

**86-021, Shutdown Due to Inoperable Emergency Service Water System

*86-022, Loss of One Offsite Power Source Causes ESF Actuation

86-023, ESF Actuation Due to EPA Breaker Trip

Unit 2

***86-007, CILRT Fails to Meet Acceptance Criteria

*Further discussed in Detail 4.2.
**Previously discussed in NRC Inspection Report 50-387/86-09; 50-388/86-09.
***Further discussed in Detail 8.0.

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 <u>LER 86-019: Entry into LCO 3.0.3 to Perform Surveillance Testing</u>

On April 28, 1986 the licensee was performing monthly surveillance testing on the 4KV bus undervoltage relays, and LCO action statement 3.0.3 was required to be entered three times in order to complete the testing.

Technical Specification Table 4.3.3.1-1 requires that monthly channel functional tests be performed on the 4KV ESS Bus Undervoltage Relays (Degraded Voltage). Surveillance procedures SM-104-009 (010, 011, 012) perform the monthly channel functional test. Similar procedures are utilized on the Unit 2 busses. Technical Specification Table 3.3.3-1 requires that 2 degraded voltage instrumentation channels per bus be operable. The associated action statement discusses a condition where only one of the two channels is inoperable. However, the surveillance test makes both channels on the bus inoperable and the action statement does not then apply, so the licensee is forced to enter LCO 3.0.3 to perform the testing on each bus.

The licensee has had some internal discussion concerning the correct LCO action statement to enter. Technical Specification 3.8.3.1 allows one 4KV bus to be deenergized for up to 8 hours prior to requiring a plant shutdown. Technical Specification 3.8.1.1 allows a diesel generator or one offsite circuit to be inoperable for up to 72 hours before a shutdown is required. Since this specific condition was not identified in these Technical Specifications, the licensee decided to enter 3.0.3, which requires shutdown action within one hour. A shutdown has not been actually caused since the surveillance procedure normally takes only twenty minutes.

The licensee has submitted a Technical Specification Change Request to clarify the proper LCO action statements applicable to these surveillances to preclude entering 3.0.3.

A similar occurrence was reported by the licensee on June 27, 1986. The appropriate LCO's were entered and a SOOR was issued. Until the Technical Specifications are revised, this monthly surveillance test will continue to generate a reportable event.

4.2.2 <u>LER 86-022, Loss of One Offsite Power Source Causes ESF Actuation</u>

On June 1, 1986 at 8:42 a.m., a repair crew working in the 500KV switchyard caused a fault signal which tripped several switchyard breakers resulting in a loss of startup transformer T-20, and auxiliary buses 12A and 12B. This loss of one independent offsite power supply momentarily deenergized 4KV ESS buses 1B, 1D, 2B and 2D. Unit 1 lost the Reactor Water Cleanup (RWCU), Control Rod Drive, and Containment Instrument Gas Systems and several containment isolations occurred. Unit 2 lost the shutdown cooling (SDC) and RWCU system and several containment isolations occurred. Common equipment lost included the B & D ESW pumps. The 'B' CREOASS train initiated and a Zone III isolation occurred. The 4KV buses were restored, and the plant was returned to a normal configuration for cold shutdown. The electrical alignment was restored at 9:50 a.m.

The Unit 2 SDC loop was lost because the 'B' RHR pump was in service, and was deenergized when the bus 2B lost power. The Unit 1 SDC loop was not lost because the 'C' RHR pump was in service. Since the two operating ESW pumps, 'B' and 'D', were deenergized, the Unit 1 'C' RHR pump lost cooling water flow. The operators decided to keep the pump in service to provide SDC and the bearing temperatures were monitored closely. The thrust bearing temperature rose to 205°F, but when power was restored the 'B' ESW pump was immediately returned to service. Shutdown cooling on Unit 2 was restored at 10:00 a.m. A 30 degree reactor vessel temperature rise occurred during the loss of SDC. The maximum vessel temperature reached was 157°F (bottom head drain).

The appropriate 10 CFR 50.72 notification was made by ENS within the required time and a SOOR was initiated by the licensee to determine the cause of the event. Both units were in cold shutdown during the event.

The cause of the event was a work plan which did not reflect the operational condition of the plant. The functional test of the 500 KV switchyard 3T circuit breaker was planned to be performed with Unit 2 operating. Since Unit 2 was in cold shutdown, the altered breaker alignment placed the electrical system in a configuration that activated the 3T breaker failure logic. Apparently, the repair crew was not aware of the operating condition that Unit 2 should be in when their test was to be performed.

To prevent future inadvertent operations while performing maintenance on equipment the in 500KV switchyard, the interface between the Division Repair Department and the station are to be improved. Additionally, recommendations have been drafted by the Electrical Test Group to be incorporated into the Systems Operating instructions and procedures.

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 report was reviewed:

-- Monthly Operating Report - May 1986, dated June 13, 1986.

-- Special Report - Diesel Generator Failure, dated June 20, 1986.

-- Monthly Operating Report - June 1986, dated July 14, 1986.

The above reports were found acceptable.

4.4 Part 21 Reports

On June 30, 1986, a 10 CFR 21 notification was made to the NRC by Morrison-Knudsen Company, Inc. The notification stated that 63 of 700 welds in the piping systems of the Fifth Diesel Generator auxiliary and starting air skids were sized below code requirements. In addition, some component support welds were found undersized.

The licensee informed the resident inspector of the notification on July 2, 1986. The licensee stated that they had been informed by the diesel-generator supplier, Morrison-Knudsen, and were pursuing corrective action. The Part 21 notification only affects components installed in the Fifth Diesel Generator Project, which is still under construction. The Part 21 Report remains open pending NRC review of the licensee's corrective action (387/86-11-01).

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:

-- SE-200-003, Primary Containment Integrated Leakage Rate Test, performed on June 10-11, 1986. (See Detail 8.0)

-- SO-252-002, Quarterly HPCI Flow Verification, performed on June 19, 1986.

At 8:30 a.m. on June 19, the inspector observed the Unit 2 HPCI Quarterly Flow Verification surveillance test, SO-252-002, which was being performed during power ascension while at 20 percent power. During the test the turbine could not attain the Technical Specification required flow and discharge pressure requirements of 5000 GPM at 1266 psig, even with the flow controller set at maximum. The system was declared inoperable at 1:00 p.m. and the appropriate LCO was entered. Adjustments to the flow controller and governor control system were made, and the test was reperformed on June 20, but it also failed. The licensee decided to disassemble the turbine governor and steam chest to investigate the cause. Disassembly of the turbine steam chest on June 21 found the stem of one of the five venturi valves (poppet valves) broken off. The failed valve effectively blocked steam flow to two of the ten steam nozzles. No other internal damage was identified. The parts were received on June 28 and the turbine was repaired on June 29. The system was full flow tested at 4:00 a.m. on June 30 and subsequently returned to service.

5.2 Maintenance Activities

The inspector observed portions of selected maintenance activities to determine that the work was conducted in accordance with approved procedures, regulatory guides, Technical Specifications, and industry codes or standards. The following items were considered during this review: Limiting Conditions for Operation were met while components or systems were removed from service; required administrative approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and QC hold points were established where required; functional testing was performed prior to declaring the particular component operable; activities were accomplished by qualified personnel; radiological controls were implemented; fire protection controls were implemented; and the equipment was verified to be properly returned to service.

These observations included:

-- Emergency Service Water Pump Repairs performed on June 7, 1986 (See Detail 7.0).

-- Limitorque Wiring Inspections performed under maintenance procedure MT-GE-003, on June 11, 1986 (See Detail 6.2).

-- Diesel Generator 18-Month Inspection performed on the 'A' Diesel Generator on July 8, 1986.

No unacceptable conditions were identified.

6.0 IE Bulletin and Information Notice Followup

6.1 IE Bulletin No. 86-01: Minimum Flow Logic Problems That Could Disable RHR Pumps

IE Information Notice 85-94: Potential for Loss of Minimum Flow Paths Leading to ECCS Pump Damage During a LOCA

IE Bulletin No. 86-01, "Minimum Flow Logic Problems That Could Disable RHR Pumps," was issued on May 23, 1986 to inform BWR licensees of a recently identified problem with the minimum flow logic for which a single failure could disable all RHR pumps, and to request certain actions by licensees following review of their logic configuration.

The licensee was requested to notify the NRC of the existence of any problem at their facility within 7 days of receipt of the bulletin, and to inform the NRC of measures taken to correct design or installation problems that may be identified as a result of the bulletin.

The licensee responded to the Bulletin on June 4, 1986 (PLA-2657) and stated that they had reviewed the design of the RHR Systems and determined that a single failure in the minimum flow logic could not disable RHR pumps in more than one loop of RHR.

Inspector review of the information submitted by the licensee in response to the IE Bulletin found it technically adequate, satisfying the requirements established in the IE Bulletin, and representing the action taken by the licensee.

The inspector conducted an independent review of the associated system drawing, M-151, and GE Elementary schematic, M1-E11-66, and verified that the minimum flow valve logic is not prone to the same failure described in the bulletin. Each division has a low flow switch, which operates its associated minimum flow valve.

6.2 IE Information Notice 86-03: Potential Deficiencies In Environmental Qualification of Limitorque Motor Valve Operating Wiring

IE Information Notice No. 86-03, "Potential Deficiencies in Environmental Qualification of Limitorque Motor Valve Operator Wiring" was issued on January 14, 1986 to alert licensee's of potential generic problems regarding the environmental qualification of electrical wiring used in Limitorque motor valve operators. The licensee was requested to review the information for applicability and consider actions, if appropriate, to preclude the occurrences of a similar problem.

The Information Notice reported the discovery of Limitorque motor valve operators with jumper wires different from those tested by Limitorque in its environmental qualification program. The internal control wiring either could not be identified or qualification could not be established where the manufacturer was known. Although Limitorque conducted environmental qualification testing of motor valve operators, the qualification reports do not specifically address wiring or wiring qualification. The Information Notice also states that if additional wiring has been added or replaced after operator shipment, then additional documentation may be appropriate for establishing qualification of the additional wires.

In response to the Information Notice and other information received from industry groups, the licensee performed an inspection of the Limitorque valve operators in harsh environments in both units during a forced outage between May 24 - June 17, 1986. The inspections included all safety-related limitorque valve operators inside containment and 17 safety-related operators outside of containment for both units. In addition to the wiring inspections, the operators were also checked for several generic problems including terminal block type, limit switch and torque switch base material, and gear box grease reliefs. All of the valves inside containment (34 valves total) had environmentally qualified torque switch wiring. However, 31 had unqualified/unidentifiable limit switch jumpers, and 12 had unqualified terminal blocks. The limit switch jumpers were replaced with qualified wire and the terminal blocks were replaced.

The valves outside containment (34 total) included 33 with unqualified torque switch wires, 29 with unqualified limit switch jumpers, and 24 with unqualified terminal blocks. In addition, 33 of the 68 valves inspected did not have a gear box relief valve. The inspections were performed utilizing maintenance procedure MT-TY-011, Limitorque MOV Environmental Qualification Inspection. All of the identified discrepancies were immediately corrected.

Following completion of the inspections, the licensee reviewed the results to determine the potential safety consequences of the identified discrepancies and to perform a reportability evaluation. The licensee determined that the problems identified were not reportable since redundant equipment in the same system (containment isolation) would have remained operable in the event of a failure of an inboard valve. Therefore, a condition did not exist that would have prevented fulfillment of a safety function. The evaluation concluded that the environment outside containment would not be sufficiently harsh to cause a valve failure. In addition, the licensee concluded that unqualified limit switch wires in containment would not be expected to fail in a manner that would cause any valve to reposition following an accident. The remainder of the safety-related valve operators are to be inspected during the next scheduled refueling outages.

The inspector reviewed the inspection results and inspection procedures and transmitted a copy of the results to the NRC Vendor Programs Branch and a Regional Specialist for review of the generic concerns. This item will remain open pending completion of the valve inspections and a review by Regional EQ specialists (387/86-11-02; 388/86-11-03).

6.3 <u>IE Information Notice 86-47: Erratic Behavior of Static-O-Ring Differential Pressure Switches</u>

IE Information Notice No. 86-47, "Erratic Behavior of Static-O-Ring Differential Pressure Switches" was issued on June 10, 1986 to advise licensees of erratic behavior of certain differential pressure switches supplied by SOR, Incorporated which apparently caused failure of the LaSalle 2 reactor to scram automatically when it was operating with water level below the low level setpoint. The licensee was requested to review the information for applicability and consider actions, if appropriate, to preclude the occurrence of a similar problem.

The Information Notice reported that Susquehanna had received shipment of similar differential pressure switches from SOR (Model No. 103/B202). The licensee found that 14 differential switches (flow switches) had been ordered for a plant modification, but the switches had not been installed in the plant. The modification had been previously cancelled. No other SOR differential pressure switches were identified. The plant does have several models of SOR pressure switches installed, but no significant problems have been encountered with these switches.

The Information Notice also stated that per plant procedure, the switches for reactor water level had been exercised prior to calibration. The inspector reviewed several licensee calibration procedures and verified that switches are not exercised prior to taking "as found" calibration data.

7.0 Emergency Service Water Pump Repairs

7.1 Temporary Repair of the 'C' ESW Pump

Following completion of the temporary repairs to the 'C' ESW pump on May 27, the pump was tested in accordance with test procedure TP-054-064, Retest 'C' ESW Pump. The test was performed on May 28, and was observed by the inspector. The test consisted of placing the 'C' ESW pump into service, with the two diesel generators aligned to the 'A' loop of ESW. The other two diesel generators were then sequentially valved into the 'A' ESW loop. The shutoff head was also obtained by closure of the pump discharge valve. The test was performed to show that the pump was functional for Operational Conditions 4 and 5, and was sufficient for normal use. The pump data taken during the test was evaluated, and the pump met the normal ISI acceptance criteria. Following evaluation of the data, the pump was placed in service and declared functional, but not operable. This restored the 'A' ESW loop to functional status.

7.2 Additional Pump Inspections

On May 27, the 'B' and 'D' ESW pumps were visually inspected. Similar cavitation damage was identified on both pumps, with 'B' being more significant than 'D'. Neither of the pumps had through-wall damage on the suction bell, as the 'A' loop pumps experienced. Based on these inspections the 'B' and 'D' pumps were declared operable for Operational Conditions 4 and 5 on May 28.

Based on the previous damage found, the 'A' pump was removed for inspection and repair on May 29. Following removal, it was found that the cavitation damage was through wall on the suction bell casing, but the four support struts were still intact. The impeller also had erosion damage, although not as severe as the 'C' pump.

Due to their similar design, the licensee decided to perform an inspection of the Residual Heat Removal Service Water (RHRSW) pumps. The RHRSW pumps are two-stage vertical circulation pumps, Byron Jackson Type 28KXL. Cavitation damage was noted on impeller wear inserts in the Unit 1 pumps and the liners were replaced. No damage was found on the Unit 2 'A' RHRSW pump. The Unit 2 'B' RHRSW pump will be inspected during the Unit 2 first refueling outage.

7.3 Pump Repairs and Retesting

Following replacement with new components, the 'C' ESW pump was reassembled and reinstalled on June 4. The 'A' ESW pump was reassembled and reinstalled on June 5. The inspector witnessed portions of the test procedure TP-054-064, Retest 'C' ESW Pump, following reinstallation of the pump. During the 'A' loop flow test, it was found that the total required flow of 8100 GPM could not be achieved. System flow reached only 7900 GPM. Since both pumps individually clearly met the ISI requirements and had an acceptable pump performance curve, it was determined that a system flow balance was required.

Repairs of the 'B' loop pumps were completed on June 8. Retests of the repaired 'B' and 'D' pumps were performed on June 10 during test procedure TP-054-066, and found acceptable. The 'B' loop, with both pumps operating, also did not meet the total system flow rate requirements. A system flow balance was completed on June 12, and both loops were declared operable.

7.4 Cause of Failure and Justification for Continued Operations

The damage to the ESW and RHRSW pumps was determined to be caused by impeller suction recirculation cavitation. The cavitation is caused by operating the pumps significantly below their design flowrates. Current ESW and RHRSW operating configurations limit the ability to operate those systems in a manner which would prevent recirculation cavitation. A review of the design and method of operation for both systems is currently being performed by the licensee to determine what changes are required to avoid recurrence. In the interim each pump will be inspected periodically. The inspection frequency will ensure the integrity of the pump is sufficient to support 30 days of continuous operation following a design basis accident. The licensee's long-term corrective action will be followed under open items 387/86-09-01; 388/86-09-01.

8.0 Containment Integrated Leak Rate Test

8.1 Procedure Review

On June 10, 1986, the licensee conducted an "as found" Integrated Leak Rate Test (ILRT) on the Unit 2 containment. Prior to the test, the inspector reviewed procedure SE-200-003, "Primary Containment Integrated Leak Rate Test", Revision 0, for technical adequacy. The inspector determined that the procedure's prerequisites, test methods, and acceptance criteria conformed with regulatory requirements and guidance. The inspector also reviewed several valve lineups in procedure PE-200-003, "Integrated Leak Rate Test Valve Lineup", Revision 1, to ensure that the systems were properly vented and drained to expose the containment isolation valves to containment atmosphere and test differential pressure with no artificial leakage barriers.

No unacceptable conditions were identified.

8.2 Test Chronology

The licensee began containment pressurization at 1:05 a.m. on June 9, 1986. During the pressurization the licensee identified three penetrations with potentially large leaks. These were all one-inch diameter containment atmosphere monitoring system lines. At 10:11 a.m. pressurization was stopped at 46.5 psig. Prior to the ILRT the licensee isolated two of the penetrations noted above, X-221A and X-60A (at 1:12 p.m. and 5:20 p.m. respectively), due to excessive leakage.

In addition, at 4:12 p.m. the Reactor Water Cleanup (RWCU) system injection vent valves (241808 and 241809) were shut after they were found to have been inadvertently left open. These valves were opened by procedure SE-200-003 to allow draining of the feedwater system and left open because they had been omitted from the RWCU valve lineup of procedure PE-200-003 in anticipation of a plant modification scheduled for the first refueling outage. The valves were not put back in the procedure when the ILRT schedule moved forward. The measured leak rate prior to shutting the RWCU vent valves and isolating penetrations X-2221A and X-60A was 3.9 weight percent per day (wt %/day). The ILRT acceptance criteria is 0.75 wt %/day. The contribution of the open RWCU vent valves was approximately 0.8 wt %/day. Consequently, the containment "as found" condition was determined to be a failure.

At 10:45 a.m. on June 10, 1986, following a satisfactory four hour temperature stabilization period, the licensee commenced the ILRT with penetrations X-221A and X-60A isolated. The ILRT was completed at 6:45 p.m. Portions of the test were witnessed by the inspectors to verify conformance to the test procedure. The inspectors also verified selected valves were in the correct position according to procedural requirements. At 8:45 p.m. the licensee commenced a four hour verification test with an imposed leak rate of 9.35 SCFM. At 6:30 a.m. on June 11, 1986 the licensee began the depressurization of containment. A two hour bypass test was started at 6:30 a.m. on June 11, 1986.

8.3 Results Evaluation

The licensee's evaluation of the data for the eight hour test between 10:45 a.m. and 6:45 p.m. on June 10, 1986 resulted in a calculated leak rate at the upper 95% confidence limit of 0.551 wt %/day for the mass point calculation and 0.592 wt %/day for the total time method. The inspector performed an independent calculation of the test results and determined that the licensee's calculations were appropriately performed and accurate. The verification test leak was 1.426 wt %/day for the mass point calculation and 1.441 wt %/day for the total time method. These results were within the acceptance band and were also verified by the inspector through independent calculation.

8.4 Corrective Action

As noted above, the containment "as found" condition was a failure due to the leakage at penetrations X-221A and X-60A. The licensee replaced the four isolation valves (SV-24780A, SV-25782A, SV-25740A, and SV-25742A) associated with these penetrations. The post-repair Local Leak Rate Test (LLRT) results (minimum pathway leakage (MPL) rates) for these penetrations were 28.3 and 25 SCCM respectively. The valves were all Target Rock one-inch solenoid operated valves. The licensee had not previously experienced problems with these valves; however, the licensee indicated a review of the valve's performance was ongoing.

In addition, there were seven penetrations in service during the ILRT and therefore not tested in the post-accident condition. The licensee performed LLRT's on five of these penetrations prior to startup. As discussed with NRR, the licensee intends to perform the LLRT on the remaining two penetrations, X-12 and X-13A (Shutdown Cooling Supply and Return), during the refueling outage scheduled to begin in August, 1986. The previous leak rate for these penetrations were used in determining the containment as-left condition.

The leak rates (MPL) for the seven in-service and two repaired penetrations, plus an error band, was 0.046 wt %/day. Applying this correction factor to the measured ILRT leak rate (0.592 %/day) results in an acceptable "as left" containment leak rate of 0.638 wt %/day.

During his discussions with the licensee, the inspector ensured that the licensee was aware that, because of the as-found failure, 10 CFR 50 Appendix J section III.A.6 requires that the schedule for the next ILRT be reviewed and approved by the NRC and that section V.B.3 requires a separate summary report of the test results. The licensee acknowledged these requirements and indicated that the final test report and accompanying summary report would be issued after completion of the LLRT on penetrations X-12 and X-13A during the refueling outage. Because of the failure of the "as found" ILRT, the licensee submitted an LER (86-007) as required by 10 CFR 50.73.

9.0 Radiological Environmental Monitoring Program

The inspector reviewed the licensee's Radiological Environmental Monitoring Program annual report for 1985. This report summarizes the results of the sampling and analyses of environmental media to determine the radiological impact of station operations. These environmental media include air, water, vegetation, and aquatic plants and animals. In addition, direct radiation is monitored by placement of thermoluminescent dosimeters at various locations around the station.

As a result of this review, the inspector determined that the licensee has generally complied with its Technical Specification requirements for sampling frequencies, types of measurements, analytical sensitivities, and reporting schedules. Exceptions to the sampling and analysis program were adequately explained, e.g., loss of sample due to vandalism. The report included summaries of the laboratory quality assurance program and of the land use survey.

The analyses of environmental samples indicated that doses to humans from radionuclides of station origin were negligible.

10.0 Security Allegation Followup

On May 5, 1986 an allegation was received by NRC Region I concerning physical security at the station. The alleger stated that he and a friend had driven onto the site in a private vehicle near the reactor building, taken some pictures, and had not been challenged by security. In response to the allegation, a physical security inspector met with the alleger on May 29, at the site. In the meeting the alleger indicated the area that he had approached. Through discussions with the alleger and reviews of the station layout drawings, the inspector concluded that the building the alleger thought was the reactor building was in fact a building under construction outside of the station security fence.

Therefore, no breach of security occurred, and the allegation was found to be unsubstantiated.

11.0 Exit Meeting

On July 21, 1986 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.