U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-387/86-09; 50-388/86-09

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: April 16, 1986.- May 27, 1986

Inspectors: R. H. Jacobs, Senior Resident Inspector

L. R. Plisco, Resident Inspector

Approved By: Jack Strosnider 6/10/86
J. Strosnider, Chief, Reactor Projects date
Section 1B, DRP

Inspection Summary:

Areas Inspected: Routine resident inspection (U1 - 97 hours; U2 - 80 hours) of plant operations, licensee events, open items, Part 21 Reports, surveillance, and maintenance.

Results: Allowable outage times for one ESW pump out of service require further review (Detail 3.4); licensee actions following 'C' ESW pump failure were prudent and conservative (Detail 3.4); MSIV jet impingement analysis is unresolved (Detail 4.5). No violations were identified.

DETAILS

1.0 Followup on Previous Inspection Items

1.1 (Closed) Inspector Followup Item (387/83-21-06): Resolution to Nitrogen Makeup Valve Isolation Signal

In August 1983, the licensee determined that a single failure of the K83 relay in the primary containment isolation logic could have resulted in a failure to isolate the nitrogen makeup line to the containment. To prevent this single failure from occurring, solenoid valve SV-15767 was deenergized and closed.

To correct this condition, the licensee installed PMR 83-746. This modification rerouted the drywell and suppression pool nitrogen makeup lines to spare penetrations and installed two isolation valves on each line. Previously, these lines shared containment penetrations with containment atmosphere control lines. This modification was previously installed on Unit 2 and was reviewed by the NRC in Inspection Report 50-387/84-14; 50-388/84-16.

1.2 (Open) Inspector Followup Item (388/84-22-02): HPCI Surveillance Procedure Deficiencies

During an observation of the performance of the Unit 2 HPCI 18-month system and logic functional test, SO-252-003, several procedural deficiencies were identified. The following corrective action was completed and reviewed by the inspector:

-- Surveillance procedure SO-252-005 was revised to clarify the pump discharge pressure acceptance criteria.

-- Surveillance procedure SO-252-003 previously had an excessive number of procedure change approval forms (PCAF) attached. The procedure has been revised and reissued as a Technical staff surveillance.

-- Surveillance procedure SO-252-003 was revised to correctly reflect the indications that would be received on a HPCI initiation, and the changes have been incorporated into the new Technical staff surveillance.

During observation of the test the inspector noted that the ECCS initiation light color convention was neither consistent between units, nor with the licensee's specifications. This human factors deficiency has not yet been corrected. The modification to change the lights is currently scheduled for completion by the end of 1986.

This item will remain open pending review of the completed modification.

1.3 (Closed) Inspector Followup Item (387/84-34-01): Moisture in HPCI Lube Oil

In October 1984, the inspector identified concerns with increased moisture content found during periodic oil samples from the HPCI system. No criteria had been set by the licensee for a maximum allowable moisture content in the oil. In addition, the licensee was unable to obtain representative samples from the lube oil system because there were no dedicated sample points in the oil lines. All samples were taken from the sump. The licensee also found a lube oil isolation valve to a bearing shut, which would have prevented oil flow to the bearing. The licensee initiated modification requests to install sample points and to install orifices to replace the isolation valves in the oil lines to the bearings.

During the Unit 1 Second Refueling Outage, the licensee installed PMRs 85-3073 and 85-8035. PMR 85-3073 replaced four ball valves with orifice plates in the lube oil supply lines to the pump bearings, turbine inboard bearing, turbine outboard bearing, and turbine gear spray. The ball valve in the hydraulic trip unit was replaced with a globe valve. PMR 85-8035 installed a lube oil sample connection in the oil line, just upstream of the oil filters. The inspector reviewed the Operational Readiness Forms which verified that these modifications were installed. In addition, Operations Procedures OP-152-001 and OP-252-001, "High Pressure Coolant Injection" were revised to incorporate a maximum limit of 0.5 percent moisture content in the lube oil. The original moisture problem has been corrected and has not recurred. Completion of modifications to the Unit 2 HPCI lube oil system will be tracked under open item 388/84-41-01.

1.4 (Closed) Unresolved Item (387/84-38-05): Fire Protection Surveillances Contain Several Minor Deficiencies

In January 1985, a review of surveillance test and maintenance records associated with Technical Specification Requirements identified several minor procedural deficiencies. The licensee completed the following corrective action in response to the findings:

-- Surveillance Procedure SE-013-003, 18-Month CO2 System Functional Test, was revised to include a procedural step to check the nozzles for flow. The procedure now confirms, by visual observation, that air is released through the discharge nozzles during the test.

-- Surveillance Procedure SM-113-004, Yearly Inspection, Hose Hydro and Flow Test of Yard Fire Hydrants, was revised to ensure a "qualified" hose (hydrostatically tested) is used to replace the hoses which are removed for testing.

-- Surveillance Procedure SM-113-008, Six Month Inspection and Weight of Halon Cylinders and Flow Verification, was revised to include a temperature probe in the list of special tools/equipment and to clarify the temperature recording and correction factor requirements.

The inspector reviewed the revised procedures and verified that the corrective action has been satisfactorily completed.

1.5 <u>(Open) Unresolved Item (387/85-01-01): Deficiencies in MSIV-LCS Procedures and FSAR Description</u>

In February 1985, a system walkdown and procedure review of the Unit 1 Main Steam Isolation Valve - Leakage Control System (MSIV-LCS) was conducted. Several procedural and FSAR deficiencies were identified. In response to the inspection findings, the licensee completed the following corrective actions:

-- The 18-month logic functional surveillance test procedure, SO-184-002, was superceded by two Technical Staff surveillance procedures, SE-183-003 and SE-183-004. The new procedures were utilized to test the system during the last refueling outage.

-- General Electric Elementary Drawing M1-E32-18 sheet 5 was revised to correctly reflect the as-built configuration of the power supplies to the 'B' and 'F' inboard system logic train.

-- A FSAR Change Request Form was issued to revise FSAR Section 6.7 to correctly reflect the current configuration of the system flow transmitters. The flow transmitters have been converted to pressure transmitters by venting the high pressure tap.

-- Plant Modification PMR-3063 was completed on Unit 1 on February 20, 1986. The modification replaced the five minute timer relays (E32-N602B, F, K and P) with 15 minute timers. The timer setpoints were changed from 3 to 13 minutes to allow more time for system flow to stabilize below 80 SCFH before an isolation occurred. The appropriate surveillance tests were completed following the system modification.

-- Operating Procedure OP-184-001, Main Steam System, was revised to identify system components consistent with the nameplate information. The associated electrical system alignment Checkoff List, CL-184-0014, now includes the test switches used for heater and blower testing.

The following items remain to be corrected:

-- FSAR Section 6.7.2.1.1 states that the pressure sensor setpoint for the outboard blower suction valve interlock is 0.5 psig, but the current setpoint is 1.0 psig. An Engineering Work Request (EWR) was generated to determine the correct setpoint, and it has not been completed.

-- Plant Modification PMR 83-112 has not yet been completed on Unit 1. The modification was originally scheduled for the first refueling outage. The modification is required to permanently incorporate the temporary changes implemented by Bypasses 82-84-05 and 82-83-17. These bypasses are approximately four years old and have yet to be implemented. The modification is currently scheduled for completion by the end of 1986.

-- The five minute timer replacement modification remains to be completed on Unit 2. It is currently scheduled for the first refueling outage which commences in August 1986.

-- The instrumentation on the control room panel 1C644 is not labeled with the instrumentation identification numbers. Operating procedure, OP-184-001, and surveillance procedure, SO-184-004, both refer to specific flow and temperature indications, which are not labeled consistently with the procedure nomenclature.

This item will remain open pending review of the completed corrective action.

1.6 <u>(Open) Unresolved Item (387/85-09-02): Discrepancies Identified in Walkdown of the Standby Gas Treatment System</u>

In March 1985, the inspector identified a number of procedural and equipment discrepancies during a system walkdown of the Standby Gas Treatment System (SGTS). These deficiencies included the following: 1) instrument root valves not included in the system checkoff list (COL), 2) inadequate labeling of SGTS components, 3) broken glass protector on damper HD-07552A, 4) dampers PDD 07554A/B not included in the COL or OP, 5) breakers for panels 1Y216, 1Y226, 1Y236, and 1Y246 not labeled, 6) adequacy of the fusible link on fire dampers in the SGTS and 7) whether the SGTS HVAC system needed to be operable for the SGTS system to be considered operable.

The licensee responded to the inspector's concerns by labeling SGTS components and including root valves in the COL. The broken glass on damper HD-07552A was repaired and dampers PDD 07554A/B were included in the OP. The breakers for the electrical panels identified above were labeled. The inspector verified that the above actions had been completed.

The licensee also evaluated the adequacy of the fusible link melting temperature for the fire protection dampers between the recirculation plenum and the SGTS trains. The fusible link melting point is nominally 160°F (not 140°F as previously thought) and the maximum temperature expected during normal or accident conditions is 104°F in this area. This provides a margin greater than 50°F. The inspector had no further concern.

The only remaining issue concerns whether the HVAC system for SGTS need be considered for SGTS operability per the Technical Specfication definition of operability and hence be required to be operable whenever the SGTS is considered operable. To date, this question has not been adequately addressed by the licensee. This item remains open pending further licensee action to address this concern.

1.7 <u>(Closed) Unresolved Item (387/85-11-02; 388/85-11-02): Discrepancies in Battery Surveillance Tests</u>

In March 1985, an inspector identified that battery surveillance tests did not include all Technical Specification (TS) acceptance criteria. Specifically, quarterly surveillance tests did not require a determination that the average of all battery cell specific gravities was greater than 1.205. Also, the surveillance procedures for the 60-month rated capacity discharge test did not require continuing the test until battery terminal voltage falls to a value equal to the minimum specified voltage per cell (usually 1.75 volts times the number of active cells). This was contrary to IEEE Standard 450-1975.

In response, the licensee revised the quarterly battery surveillance tests for Units 1 and 2 24 volt, 125 volt, and 250 volt batteries to include the specific gravity acceptance criteria. The 60-month battery discharge performance tests for all batteries were revised to require testing until the minimum specified voltage was achieved. The inspector verified that the above procedures were revised.

1.8 <u>(Closed) Violation (387/85-16-04): Sliding Links Left Open in The Emergency Service Water (ESW) System</u>

In April 1985, the licensee determined that sliding links had been left open which caused the inoperability of one loop of ESW. The links had been left open during modification work performed during the Unit 1 first refueling outage, and the condition had existed for about four weeks. Subsequently, during a panel inspection of the plant, some additional sliding links were found open, which affected other safety and non-safety systems. This matter was the subject of special inspection 50-387/85-16; 50-388/85-15 and was discussed at an enforcement conference on May 31, 1985.

In response to the violation, the licensee initiated an investigation into the circumstances associated with the open sliding links and conducted an inspection of all Q-listed panels and some non-Q panels, on both units. All links found open were evaluated and dispositioned. The licensee concluded that the cause of the event was that a contract construction electrician had opened the sliding links in the ESW panel without proper authorization. Nevertheless, as evidenced by the other links found open, the controls governing sliding links were weak and not fully disseminated to all plant workers.

To prevent future occurrence, the licensee strengthened the controls over sliding links (as well as other terminations in panels) as follows: Administrative Directive AD-QA-904 "Control of Modification Work in Existing Plant Electrical Panels" was written to control modification work and require that only PP&L personnel who have received specific training delineated in this AD, can perform work in existing plant panels. The AD was later revised to permit certain specifically designated contractor electricians, who had the same experience and training specified in the AD, to also perform this work. The list of contractor personnel was to be minimized and approved by the Station Superintendent. In a letter to Region I dated Fabruary 24, 1986, PP&L discussed the above revisions.

The licensee now conducts an inspection of all safety related panels for open sliding links on the affected unit and common panels following every outage of greater than six weeks duration. This was a commitment made to the NRC at the May 31, 1985 enforcement conference. The licensee also conducts periodic sliding link inspections of some panels every six months. This program is implemented by procedure MT-GE-026, "Safety Related Panel States Link Inspection". The inspector reviewed the results of this inspection following the Unit 1 second refueling outage. One link was found open which could not be accounted for, out of 107 panels inspected. This link supplied an annunciator for the ESW system. A few other links were found partially open, but there was continuity across the links. These links were reclosed under WA S60732. It should be noted that a sliding link was found open in panel 1C016 during performance of a HPCI test procedure. This item is tracked under item 387/86-06-02. The inspector verified that panel 1C016 had not been inspected for open states links prior to this occurrence.

In addition to the above actions, the licensee conducted training for all operators and upgraded the training program for contractors, in the area of station policies and programs.

1.9 <u>(Closed) Inspector Followup Item (387/85-18-02): Overpressurization Potential for ECCS Systems</u>

In June 1985, the inspector performed a review of the overpressurization potential for ECCS systems. This review identified the following potential concerns: Specific maintenance procedures did not exist for repair of the RHR and Core Spray testable check valves; QC involvement was not evident with maintenance on the testable check air actuator or pilot solenoid valve; and cautions were not included in the 1000 psig leak check procedures concerning the potential for overpressurization.

In response, the licensee developed maintenance procedure MT-GM-028, "Testable Check Valve Actuator Maintenance". The procedure provides specific maintenance instructions necessary to perform maintenance on the testable check valve actuators in the Core Spray and RHR systems. The procedures contain specific precautions for connecting/disconnecting cylinder and solenoid air fittings to the actuator air lines and specifies that a sketch of the solenoid valve and air tubing configuration be made prior to disassembly.

Quality Assurance performed a surveillance, 85-114, to investigate licensee action taken for IE Information Notice No. 84-74 concerning ECCS system overpressurization. In the surveillance, QA concluded that plant procedures and functional/operational testing were adequate to preclude any of the events described in Information Notice No. 84-74. They also concluded that periodic QA surveillances preclude the need for QC witnessing of work on the non-Q testable check valve actuator.

The licensee also revised the 1000 psi leak check procedures to include cautions on the potential for overpressurizing low pressure systems. The above actions resolved the inspector's concerns.

1.10 <u>(Closed) Unresolved Item (387/85-21-02): LER 85-023, Excess Flow Check Valve Isolation Valve Left Open</u>

In July 1985, the licensee issued LER 85-023 due to an excess flow check valve isolation valve being inadvertently left open. The valve was required to be closed due to the inability to perform surveillance testing on excess flow check valve XV-141F009. In the inspector's view, the corrective actions for this occurrence as delineated in the LER were insufficient.

By letter dated February 11, 1986, the licensee supplemented this LER, which included additional corrective actions. The following additional actions were taken: Unit 1 and Unit 2 operating procedures, OP-164/264-001 were revised to require that the normal position of the isolation valves (141005/241005) be locked closed. Integrated Leak Rate Test (ILRT) lineup procedures, PE-100/200-003 were revised to require that these valves be locked closed on restoration of the ILRT. Operations personnel were informed of the occurrence. Plant modifications to allow testing of the excess flow check valve were completed during the second refueling outage for Unit 1 and will be completed during the first refueling outage for Unit 2. The associated operating procedure and ILRT lineup for Unit 1 were revised to reflect the modification.

1.11 <u>(Closed) Inspector Followup Item (387/85-28-02): FSAR and Procedure Revisions for Excess Flow Check Valves</u>

During a review of the periodic testing requirements for the instrument line excess flow check valves, several FSAR and procedural deficiencies were identified. The following corrective actions were completed to resolve the item:

-- The Unit 1 and Unit 2 Pump and Valve Inservice Inspection Testing Program have been designated to include the correct surveillance procedure references during the next revision.

-- FSAR Change Request 1399 has been submitted to revise Table 6.2-12a to correctly reflect the as-built condition, and to include all of the instrument lines which penetrate containment.

The proposed FSAR revisions and ISI program change were reviewed and found acceptable.

1.12 <u>(Closed) Inspector Followup Item (387/85-31-03): Reactor Water Cleanup (RWCU) System Spill</u>

On October 11, 1985, a spill of radioactive coolant and resin from the Unit 1 RWCU system occurred. The spill occurred when an operator was manually operating the RWCU filter/demineralizer (F/D) control programmer in an effort to stroke a F/D flow control valve. The licensee's review of the incident identified that the spill occurred because the low pressure precoat portion of the RWCU system was not isolated from the high pressure piping due to a design problem and a failed valve. Specifically, the programmer design required that the vessel be "deisolated" (i.e. isolation valves HV-14531A and HV-14532A,

opened) while the low pressure precoat piping was connected to the F/D vessel. With this design, there is only a single valve isolating low pressure piping from high pressure. The spill occurred when flow control valve FV-145661 inadvertently opened. The licensee also identified that FV-14566A had an eroded valve seat and the seat was replaced.

The licensee modified the programmer circuitry under DCP 85-9054. The change effectively ensures that two valves in series will isolate the F/D precoat system from high pressure. This change has also been installed on Unit 2. The appropriate operating procedures, OP-161-001 and OP-261-001, were revised to reflect the modification and to ensure manual isolation valves to low pressure piping (i.e. F/D vent piping and precoat piping) are shut prior to deisolating the vessel, as a further precaution. LER 85-32 identified no further corrective actions. Nuclear Safety Assessment Group (NSAG) Project Report No. 1-86 identified a number of other specific recommendations which are being tracked by the compliance and NSAG groups. Sufficient actions have been taken to prevent similar occurrences, however, and no further NRC followup is necessary.

1.13 (Closed) Inspector Followup Item (387/85-36-01): Discrepancies Identified in CREOASS Walkdown

In January 1986, the inspector performed a walkdown of the Control Room Emergency Outside Air Supply System (CREOASS) and identified a number of discrepancies. These discrepancies included the following: 1) The positions of several dampers were not checked in the checkoff list (COL), 2) Root valves for CREOASS instrumentation were not labeled or included in the COL, 3) Power supplies for the actuation logic were not included in the COL, 4) Operability of the SGTS HVAC was not included in Operating Procedure OP-030-002, 5) The labeling of CREOASS components was inadequate, and 6) Drawing VC-178 incorrectly showed dampers HD-07802A and B in reverse order.

In response, the licensee labeled CREOASS components and root valves, and included the root valves and missing damper in CL-030-0025. Power supplies for the CREOASS logic were included in CL-030-0024, the CREOASS electrical checkoff list. SGTS HVAC system operability was included in the operating procedure. The inspector verified that the above actions were completed. Drawing VC-178 is being revised to show the correct orientation of HD-07802A and B. The inspector had no further concerns.

1.14 <u>(Closed) Violation (387/86-02-03): Installation of an Expired Squib Valve in the Standby Liquid Control System</u>

In February 1986, a Standby Liquid Control System (SLCS) primer assembly was found installed in the system which had exceeded the vendor recommended shelf life of five years. This was a violation of 10 CFR 50 Appendix B, Criterion XV and station procedures. A successful firing test of the squib was subsequently performed, demonstrating that the system had been operable. Delays in obtaining shelf-life information from General Electric, and changes in the shelf-life tracking system may have contributed to the lack of the expiration date on the tag.

In response to the violation, the licensee inspected all primers in stock and found that they were properly tagged and included the shelf life expiration date on the tag. No other expired primers were identified. Training was conducted with Warehouse personnel addressing shelf-life program commitments and requirements. Special notes were incorporated into the Material Management System concerning the shelf-life of primers and batch qualification requirements.

The applicable surveillance procedures, SE-153/253-001, Standby Liquid Control System Eighteen Month Initiation and Injection Demonstration, were revised to assure that adequate shelf-life (36 months) remains whenever new primers are installed following the 18-month surveillance test.

The inspector reviewed the applicable training rosters, the Material Management System Primer description, and the revised surveillance procedures to verify the licensee's corrective action. The corrective action taken by the licensee is acceptable and should prevent recurrence.

2.0 <u>Review of Plant Operations</u>

2.1 <u>Operational Safety Verification</u>

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.

During a tour of the Unit 2 turbine building, while following up a worker concern, the inspector noted that the floor vibration from the turbine appeared to be more significant than on the Unit 1 turbine deck. Further inspection noted that the switchgear panels in the two elevations below the turbine deck were also vibrating. A walkdown of the panels did not identify any safety-related equipment that may be affected. During the Unit 2 startup program, there were vibration problems with the main turbine, but they were corrected. The inspector reviewed the plant computer data to compare the vibration data for the two turbines, and there was not a significant difference between them. Discussions with the Technical Staff also found that the Unit 2 HP rotor will be disassembled and inspected during the next refueling outage and should correct some of the vibration. The inspector had no further concerns.

3.0 Summary of Operating Events

3.1 Unit 1

The second refueling outage, which commenced February 25, 1986, was completed and reactor startup began on April 19. Following criticality and heatup, the reactor was manually scrammed on April 20 to perform control rod scram testing. The reactor was restarted on April 21 on the other rod sequence, and then manually scrammed from full pressure on April 21 to check rod timing. The reactor was restarted on April 22 and the generator was synchronized to the grid on April 23. Power ascension to about 50% power was completed, but the licensee was unable to perform LPRM calibrations and thermal limit determinations due to an inoperable 'A' TIP indexer. The unit was shutdown

on April 24 to enter containment to repair the TIP indexer. The indexer was repaired and startup began on April 25. Power escalation followed and startup testing continued. Full power was reached on May 1. Operation at or near full power continued until May 24 when the unit was shutdown due to ESW pump damage (Detail 3.4).

3.2 Unit 2

Unit 2 operated at or near full power for most of the inspection period. Scheduled power reductions were conducted throughout the period for control rod pattern adjustments, surveillance testing and scheduled maintenance. On May 8, End of Cycle was reached, with all rods out and 100 percent core flow. Coastdown continued until May 24 when the unit was shutdown due to ESW pump damage (Detail 3.4).

3.3 Fifth Diesel Generator (D/G) Tie-In Switches

On April 15, the "D/G 'A' Not in AUTO" alarm was received at the electrical control panel in the control room. An operator was sent to the local D/G control panel in the 'A' D/G bay. Nothing abnormal was found at the control panel. The operator was then sent to check the fifth D/G transfer panel (OC512A) in the upper level of the 'A' D/G bay. The operator found two of the twenty transfer switches aligned to the 'E' or fifth D/G instead of the 'A' D/G and a third switch, HS-00057A, was in the disable position. This switch alignment was in disagreement with the system check-off list and the operator was directed to return the switches to the 'A' position and the HS-00057A switch to the "Enable" position. When the third switch was returned to the "Enable" position, the "D/G 'A' Not in AUTO" alarm cleared. On the direction of the control room, the operator then positioned the switches to the alternate position, one at a time and then returned them to the normal position. When switch HS-00075A (one of the three affected switches) was positioned to the 'E' position, the 'A' D/G started. This switch was then returned to the 'A' position and the D/G was manually shutdown.

The inspector reviewed this occurrence to determine the cause of the mispositioned switches and controls over the fifth D/G transfer panel. The inspector reviewed SOOR-1-86-125, electrical schematics and Alarm Reponse Procedure ARP-015-001, and discussed the incident with plant engineers and the Operations Supervisor.

The 'E' D/G was "tied-in" to the 'A' D/G control circuitry under modification DCP 83-812B. The 'A' D/G was the only D/G which had control circuitry connected to the 'E' D/G. This work was performed in January 1986. The revised schematics showing the tie-in were posted on controlled drawing stick files, the Alarm Response Procedure (ARP) for the "D/G 'A' Not in AUTO" alarm had been revised to account for transfer switches out of the normal position and training had been conducted for the operators on the effects of this modification.

No work was authorized which could affect the switches in the transfer panel (OC512A) at the time of this incident. The licensee identified and interviewed some contractor electricians who were working on terminal lugs inside OC512A at the time. Although these individuals did not indicate that they had moved any of these switches, it was determined that they crossed in front of the panel carrying bags and there is only a small clearance between the panel front and a railing. The switches are all pistol grip switches with large handles, which if bumped, would easily be knocked out of their normal position. Therefore it was determined that the switch mispositioning was probably due to these individuals.

Switch HS-00057A was in the "Disable" position when the operator was dispatched to OC512A. Based on schematic E-184, Sheet 2, IDCN 12, this switch disabled all D/G auto-start logic for the 'A' D/G. However, the period of time that the 'A' D/G was disabled was relatively short since this condition caused the "D/G 'A' Not in AUTO" alarm to be annunciated and an operator was immediately dispatched to investigate. The operator took the correct action to return the switches to their normal positions, as specified in ARP-015-001, G-10. However, at the control room's direction, the switches were taken one at a time back to the 'E' position. The operators were not familiar with the potential consequences of further manipulation of these switches. The inspector verified that manipulation of switches in the proper order is important. If the incorrect order is performed, it is possible to cause a D/G start (which happened in this case) or cause equipment damage. For example, if other switches were in the improper position, a D/G auto-start without corresponding start of its associated ESW pump could occur resulting in lack of cooling for the D/G. In response to the inspector's concerns, the ARP was revised to specify the proper order for switch manipulation and additional training was conducted with all operating personnel and contractor electricians on this incident. In addition, the transfer panel is presently roped off to prevent passage in front of the panel until construction work is completed. The inspector had no further concerns.

3.4 'C' ESW Pump Failure - Alert Declaration

3.4.1 Summary

At 12:00 p.m., May 24, the licensee declared an Alert condition, based on declaring all ESW pumps inoperable. The determination was made based on the condition of the 'C' ESW pump which failed on May 21 and the condition of the 'A' ESW pump as determined by a diver on the morning of May 24. A shutdown of both units was commenced. Flow was reduced to minimum on both units with the recirculation pumps and Unit 2 was manually scrammed from about 27% power at 3:30 p.m. Unit 1 was manually scrammed from about 22% power at 5:55 p.m. A cooldown was performed on both units with Unit 2 reaching Operational Condition 4 (cold shutdown)

at 2:00 a.m., May 25, and Unit 1 reading cold shutdown at 6:45 a.m., May 25. The Alert condition was terminated at 10:00 p.m., May 24. The Techical Support Center was continuously manned during the Alert.

3.4.2 Pump Failure

At 12:25 a.m., May 21, operators received an overcurrent alarm on the 'C' ESW pump. An operator was dispatched and he noticed that the pump discharge check valve was shut, although the motor was still running. The pump was turned off. Plant computer data showed that the pump was drawing about 60 amps of current (which is normal), then it increased to 76 amps and then went offscale. The current then returned to 23 amps. The pump was declared inoperable at 1:00 a.m. May 21. Since the 'D' D/G was out of service for tie-in to the fifth D/G and the 'D' D/G supplies emergency power to the 'D' ESW pump, a 72 hour LCO was declared for two ESW pumps out of service. The 'D' D/G was returned to service at 1:30 a.m., May 23. Maintenance prepared maintenance procedure MT-054-001, "Emergency Service Water Pump Disassembly and Reassembly" and began pump disassembly under WA-S64627. The pump is a Byron Jackson 24BXF, 1-stage, 6000 gpm, 100 psi centrifugal pump.

On May 23, it was determined that the pump was severely damaged as follows: the pump suction bell was eroded/corroded completely around its circumference, including all four structural struts such that the bottom portion of the suction bell had fallen off; the pump shaft had sheared just below the impeller, and there was significant erosion of the impeller vanes, near the impeller eye. Based on the condition of this pump, the licensee decided to have the 'A' ESW pump and two RHRSW pumps inspected by a diver. On May 24, the diver identified that similar 360°, through wall erosion/corrosion existed on the suction bell of the 'A' ESW pump. All four structural struts also had metal loss, but three of the four appeared intact and attached to the upper portion of the suction bell. The diver did not identify any damage with the RHRSW pumps. Samples of the 'C' ESW pump suction bell were sent to the PP&L Hazleton labs for failure analysis. The results of this analysis are not yet available.

The inspectors reviewed the previous ESW pump performance data. Testing was performed in April 1986 with no abnormalities or trends noted from previous testing. The data indicated that the 'C' pump was able to pump about 6000 gpm at a differential pressure of 72 psid. Motor vibration data was 0.35 mils which is less than the 1 mil acceptance criteria. No pump vibration data is taken since the pump is fully submerged. Of the four pumps, the 'C' ESW pump had the highest number of operating hours, greater then 19,000, as compared to about 17,700 for the 'A' and 'B' pumps, and 11,400 for the 'D' pump.

3.4.3 ESW System

The ESW system consists of two independent piping loops, each loop consisting of two pumps which take water from the spray pond, (ultimate heat sink), pump it through various heat exchangers and return it to the spray pond via the spray headers or bypass valves. Each of the two loops supplies both Unit 1 and Unit 2 loads. The 'A' and 'C' pumps are in one loop; the 'B' and 'D' pumps are in the other loop. The ESW system provides cooling water to the following:

-- all diesel generator heat exchangers;

-- all RHR pump bearing oil coolers, seal coolers and room coolers. ('A' ESW loop supplies 'A' and 'D' pumps, 'B' loop supplies 'B' and 'C' pumps);

-- room coolers for Core Spray, HPCI and RCIC;

-- control structure chillers and direct expansion unit;

-- Reactor Building and Turbine Building closed cooling water systems if service water is unavailable (manual shift).

On May 23, the inspector noted that the 'B' loop of ESW was aligned to the diesel generators (D/G) instead of the normal 'A' loop alignment. In addition, the licensee had entered a seven day LCO for loss of one ESW pump in accordance with T.S. 3.7.1.2.a.1. The inspector expressed a concern that the licensee should remain in a 72-hour LCO because of the alignment of the 'B' loop to the D/Gs. This issue was previously identified in Inspection Report 387/85-18 and is still unresolved. The 'A' ESW loop logic includes an automatic transfer feature to the 'B' ESW loop on low flow, but the 'B' loop does not have this feature. With the diesels aligned to the 'B' ESW loop, a single failure of the 'B' ESW loop bypass valve could lead to failure of all diesel generators. The same situation applies with one ESW pump inoperable, since loss of the 'A' or 'C' ESW pumps will cause an auto-transfer of the diesels to the 'B' loop, and loss of the 'B' or 'D' pumps will prevent an auto-transfer of the diesels to the 'B' loop. Therefore, the consequences of loss of one ESW pump

appear the same as loss of one entire ESW loop. Hence, it appears that the Technical Specifications do not properly account for the auto-transfer feature. This issue will be reviewed with NRR and tracked under open item 387/85-18-01. In response to the inspector's concern, the licensee remained in the 72-hour LCO.

While repairs to the 'C' pump were ongoing, the licensee developed plans to optimize the ESW lineup and prepared contingency plans for actions to provide cooling water while in cold shutdown in the event of further degradation of the ESW system. These actions were delineated in procedure, OP-OTY-007, "RHR Shutdown Cooling Operation With 'C' ESW Pump Unavailable". Since the 'D' pump had the fewest operating hours, it was used only as a backup, in the event of failure of the operating pump ('B' ESW pump). In the event of loss of all ESW, the procedure specifies implementation of predeveloped work authorizations to connect via a temporary piping system, RHRSW to provide RHR pump cooling; use of fire hoses and the diesel driven fire pump to provide cooling to two diesel generators; and realigning reactor building ventilation to provide room cooling as a substitute for normal ECCS pump room coolers.

3.4.4 Temporary Repair to the 'C' ESW Pump

From May 24 through May 27, maintenance personnel implemented a temporary repair to the 'C' pump. As of the end of the report period, replacement parts for the pumps are unavailable until at least June 3. The temporary repairs consisted of using devcon to fill in the eroded impeller, welding a 20-inch centerline carbon steel, 0.8-inch thick spool piece to both ends of the suction bell and using Belzona R Ceramic to fill in and smooth out the corroded area between the two suction bell halves. The inspectors reviewed the work plan, discussed the repairs with maintenance and engineering personnel and observed portions of the repair. Testing of the repaired pump was scheduled to begin on May 28. This repair is considered temporary; the licensee intends to install a new suction bell and other parts when they are available, prior to startup.

The licensee's actions to examine the condition of the other ESW and RHRSW pumps and the decision to shutdown both units was prudent and conservative. The licensee's actions to restore the ESW system to an acceptable configuration prior to startup, as well as failure analysis results and long-term corrective action, will be reviewed in a subsequent inspection. (387/86-09-01; 388/86-09-01)

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

86-008, RPS Actuations Resulting From Testing Combined With CRD Change-Out

86-009, Intermediate Range Monitor Upscale Spike Causes Reactor Scram

*86-010, Violation of Secondary Containment When Recirculation Plenum Hatches Opened

86-011, IRM/SRM Spikes With Shorting Links Removed

86-012, SGTS & CREOASS Start Due to Blown Fuse

86-013, SBTS System Initiated Due to a Procedure Deficiency

*86-014, Two Scram Discharge Volume Level Transmitters Found Isolated

86-015, Division II Containment Isolation Due to Blown Fuse

**86-016, Valve Packing Leak Leads to Reactor Scram Signal

86-017, Inadequate Electrical Contact Causes Initiation of SGTS

86-018, Division I Containment Isolation When ±A' RPS Bus Power Lost

Unit 2

86-005, Standby Gas Treatment System Manually Initiated

86-006, RWCU Isolation on High Differential Flow

*Previously discussed in Inspection Report 50-387/86-06; 50-388/86-04

**Further discussed in Detail 4.2

4.2 Onsite Followup of Licensee Event Reports

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

4.2.1 LER 86-016, Valve Packing Leak Leads to Reactor Scram Signal

On April 12, 1986, an auto scram signal was generated when reactor vessel level dropped to 13 inches. The reactor was already in cold shutdown so there was no rod movement. Level was being lowered by the operators after the operational hydrostatic test. The operators were reducing level from about 217 inches to between 90 and 100 inches on the shutdown range indicator, which is calibrated for cold conditions. While level was at about 154 inches on shutdown range, level began coming on scale on the narrow range level indicators. The operators noted the level indicators coming on scale and noted the turbine trip on high level and vessel to high level alarms clear. They also received a low level alarm at about +30 inches. The operators apparently did not believe these level indicators because all other level indicators were still off scale high. Hence, the draining evolution was not stopped until the low level scram setpoint was reached.

The inspector reviewed SOOR 1-86-118 and discussed this incident with Operations personnel. Shutdown range indication was about 109 inches when the scram occurred. It was determined that there was a packing leak on the shutdown range equalizing valve which may in part have caused the level indication discrepancy.

The affected operators did not realize that a scram would occur if draining was continued. They knew that the narrow range level instruments were not calibrated to cold depressurized conditions and hence, did not believe the indication. Whether or not the indication is accurate, the narrow range instruments will cause a scram when at +13 inches indicated. The operators have been counseled and all operators will be trained on the event during the requalification cycle.

In addition, although not stated in the LER, procedures SE-100/200-002 for the operational hydrostatic test are being revised to specify venting the vessel prior to draindown, add cautions to the operators to be alert to narrow range level instrumentation during the draindown, and to refill the shutdown range reference leg prior to drawing below the main steam lines. The inspector had no further concerns.

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 - April 1986, dated May 15, 1986.

The above report was found acceptable.

4.4 Part 21 Reports

On May 9, 1986 a 10 CFR 21 notification was received by the NRC from Dravo Constructors, Inc. (DCI). The notification stated that anchor bolts supplied by Hilti Fastening Systems do not meet the average ultimate tensile loads in certain sizes as published in the vendor design manual. Design calculations based upon the published values could be below the acceptable loads required for specific designed items.

The licensee also informed the resident inspectors of the notification on May 12, 1986. The licensee stated that they had been informed of the deficiency by the Fifth Diesel Generator Constructor, DCI, and were pursuing corrective action. DCI stated in the Part 21 notification that the engineer, Gibbs & Hill, Inc., was to perform a design review of all items installed using Hilti Bolts not meeting the catalog test values and to provide resolutions to the constructor for implementation.

The inspector reviewed DCI Nonconformance Report (NCR) 462, which documented the Hilti Test results. Testing of Hilti Kwik and Super Kwik expansion anchors performed on April 7 - 8, 1986 at Susquehanna found that the average percent of ultimate pullout strength achieved was as low as 59 percent for some anchors. Based on the test results the acceptability of the anchors was declared indeterminate.

The licensee stated that the Part 21 notification only affects bolts installed in the Fifth Diesel Generator Project, which is still under construction. The Part 21 report remains open pending NRC review of the licensees corrective action. (387/86-09-02)

4.5 MSIV Jet Impingement Analysis

On May 8, 1986 the licensee informed the resident inspectors of a deficiency identified during a review of the jet impingement effects on the main steam isolation valves (MSIV) during a recirculation line break.

Section 3.6 of the FSAR and 10 CFR 50, Appendix A, General Design Criterion 4 require that components important to safety be protected against the effects of pipe break. For the postulated break of the 28" reactor recirculation suction line at the pipe-to-safe end weld at RPV nozzle N1A it was discovered that the resultant steam/water jet will impinge upon the two innermost of the inboard main steam isolation valves (B21 - 1F022A & B21 - 1F022D), and that the jet impingement force exceeds that for which the valves are qualified. The analysis indicated that the operators would fail preventing the valves from performing their design safety function. This specific pipe break in the recirculation system, which could prevent the closing of two inboard MSIV's, combined with an independent failure of the outboard MSIV's to close, is outside the plant design basis.

The licensee issued a Nonconformance Report (NCR 86-0019) on January 13, 1986 to describe the condition.

After further evaluation, a Safety Evaluation Report (SER) was prepared to justify continued operation and was reviewed by PORC on May 9. PORC concluded that no unreviewed safety question exists and approved the SER. The licensee also determined that the item was not reportable since the design deficiency was not of significant safety consequence.

The NCR was dispositioned as a conditional release until the third refueling outage, when a formal "leak-before-break" analysis can be completed. The justification is based on the following:

1. Due to the IGSCC mitigation steps that have been performed (i.e. IHSI), the ISI weld inspections, and the installed leak detection capability, the licensee believes that any failure would be of the "leak-before-break" (LBB) mode and would post no threat to any safety related equipment. A formal LBB analysis is to be completed based on NUREG 1061.

2. Inspections have been and continue to be performed to verify the integrity of the weld. The inspections include construction radiographs, PSI ultrasonic inspections, post IHSI ultrasonic inspection and ISI ultrasonic inspection during the second refueling outage.

3. The probability of a pipe break at the precise location and of a nature that would cause jet impingement in the time it would take to complete the analysis is extremely low. Additionally, the probability of the single failure being a failure of the corresponding outboard MSIV's is also extremely low.

Based on the above justification, the licensee is planning to perform an analysis, and is actively pursuing solutions to remedy the problem should the renalysis confirm that the ability of the valves to perform their safety function may be compromised. The licensee has also discussed the item with NRR.

This item will remain unresolved pending completion of the liensee's reanalysis. (387/86-09-03; 388/86-09-02)

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:

-- TP-152-009, HPCI Pump Performance Verification, performed on April 29, 1986

-- TP-024-058, PMR 83-812B Retest, performed on the 'D' diesel generator on May 22, 1986.

During the HPCI test, the licensee used both loops of RHR for suppression pool cooling and the 'A' loop of Core Spray to mix the suppression pool water. Use of Core Spray for mixing is necessary because the suppression pool temperature detectors are relatively near the pool surface, as is the HPCI turbine exhaust discharge.

Mixing of the pool is necessary to ensure that measured suppression pool temperature is representative of actual pool temperature. Suppression pool temperature increased from about 72°F to about 96°F during the 1 hour and 25 minute HPCI run. Technical Specification 3.6.7.1 permits suppression pool average temperature to rise to 105°F during HPCI testing.

The inspector's concern is that, during this test, all ECCS systems except one loop of Core Spray, is in a full flow test alignment, which is different than its normal injection lineup. In 1984, the licensee identified a concern that during a LOCA with loss of offsite power, if the RHR and Core Spray systems, are in the test mode, they will realign to the injection mode. During the valve realignment, a flow path is created which could cause draining of the pump discharge header to the suppression pool in both of these systems while the pump is without power (i.e. before loading on the diesel generators). This creates the possibility of a waterhammer. The consequences of a waterhammer have not been analyzed in detail. In addition to the waterhammer potential, due to the relatively long closure times for the RHR and Core Spray full flow test valves, water will be diverted from injection flow to the suppression pool until the test valves are shut, thereby potentially jeopardizing peak clad temperatures.

A broader question deals with the amount of time RHR must be used in the suppression pool cooling mode (which serves as a full flow test alignment). ECCS analyses do not analyze for a design basis accident while in the full flow test or suppression pool cooling mode because it's assumed that this is a very low probability occurrence. However, Unit 2 uses suppression pool cooling almost continuously due to pool heatup from leaking safety relief valves (SRVs).

The licensee has recognized the above concerns and is taking some action to address these concerns. Procedures are being revised to prohibit use of RHR and Core Spray in full flow test at the same time. The licensee intends to rework the leaking SRVs during the upcoming outage. Other analyses are in progress or planned to address the waterhammer concern and injection flow delay times. This issue is considered unresolved pending further review. (387/86-09-04; 388/86-09-03)

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:

-- Replacement of Reactor Vessel Level Switch LIS-B21-2N024B (WA V-66287), performed on May 16, 1986.

-- Repair of the 'D' Diesel Generator (WA S61033), performed on May 22, 1986.

-- Temporary repair of the 'C' ESW Pump (WA-S64627), performed between May 24 - 27, 1986. (Detail 3.4)

No unacceptable conditions were identified.

6.0 Survey of Licensee's Response to Selected Safety Issues

A review of licensee actions in response to issues identified in specific IE bulletins, circulars, and information notices and in the Institute of Nuclear Power Operations (INPO's) significant operating event reports (SOERs) was conducted. The two issues reviewed were HPCI/RCIC system reliability and Biofouling of cooling water heat exchangers.

6.1 Reliability of HPCI/RCIC Systems

INPO SOER's 81-13 and 82-14 discuss failures of the HPCI and RCIC systems and provide recommendations to improve their reliability. The licensee performed an evaluation of the SOER's under Industry Event Review Program (IERP) 81-107 and 83-001. The majority of the recommendations had been previously implemented and several other reliability and availability improvements were incorporated in response to the reports.

Several of the INPO recommendations were not included into the licensee's programs:

-- SOER 81-13 recommended that the HPCI and RCIC systems should be tested for operational readiness by cold quick-start testing at appropriate periodic intervals and after specified types of maintenance. SOER 82-14 also discusses that although cold quick-start testing is not an explicit requirement of technical specifications, that it is the only test that ensures that all components, control systems, and instrumentation are functioning correctly for auto-initiation triggered by low reactor water level. The licensees review of the recommendation, during IERP 81-107, determined that no action was necessary since this testing had already been incorporated into the surveillance testing procedure.

Inspector review of the applicable surveillance procedures found that the recommended testing method was not currently being utilized. For example, in the HPCI quarterly flow verification procedure, SO-152-002, the turbine is started up with the flow controller in manual, and set at minimum speed. After the turbine is started it is slowly brought up to rated speed. This method is also not consistent with the recommendations contained in GE SIL 336. A hot automatic start of the HPCI turbine is performed every 18 months by surveillance procedure SO-152-005, but not at rated conditions. The RCIC procedure provides the operator/engineer the option of using the cold quick-start method during the quarterly flow verification, SO-150-002, but it is seldom utilized.

The inspector discussed the inconsistencies with the system engineer and IERP coordinator. They stated that they would rereview the reasoning for the current methodology, and make appropriate changes if necessary.

-- SOER 82-14 recommends that humidity and temperature in the HPCI/RCIC rooms be monitored and controlled to minimize degradation of the equipment. Humidity is not currently monitored in the ECCS rooms. The licensee determined that humidity monitoring is not necessary since the equipment is qualified for 90 percent humidity under normal operating conditions. The rooms contain temperature monitors and are inspected every shift during operator rounds.

6.2 Biofouling of Cooling Water Heat Exchangers

INPO SOER 84-01 deals with the degradation of cooling water system capability due to aquatic life and provides recommendations to monitor heat exchanger performance. The licensee performed an evaluation of the SOER under IERP 84-051. Susquehanna has not had problems with the growth of shellfish in plant cooling systems, and the river sampling program has not yet found any Asian clams in the Susquehanna River near the plant. Susquehanna also has a closed-cycle emergency service water system, and the majority of industry problems have involved open-cycle systems.

There have been occurrences of small fish found in the spray pond. The fish were killed by a chemical treatment and removed from the pond. In 1982 the diesel generator intercoolers had to be replaced due to tubing degradation caused by ammonia. The ammonia was

believed to have been generated by the decay of organic material in the spray pond. There has also been a sludge buildup on the bottom of the spray pond, mainly due to dead algae and marine vegetation, but there have not been any instances of biofouling.

The INPO recommendations have not yet been implemented. The licensee is currently evaluating the installed instrumentation to determine if adequate instrumentation is available to monitor heat exchanger performance. In addition, a program is being developed to monitor heat exchanger performance. Some of the potentially affected heat exchangers, such as the diesel generator heat exchangers, are inspected every two years.

7.0 Exit Meeting

On May 27, 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.