U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-387/87-12; 50-388/87-12

Docket Nos. 50-387; 50-388

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: July 1, 1987 - August 15, 1987

Inspectors: L. R. Plisco, Senior Resident Inspector
J. R. Stair, Resident Inspector

Approved By: [signature] 9/4/87
J. T. Wiggins, Chief, Reactor Projects Section 1B, DRP — Date

Inspection Summary:

Areas Inspected: Routine resident inspection of plant operations, radiation protection, physical security, plant events, previous inspection findings, surveillance and maintenance.

Results: A Technical Specification change was not promptly implemented (Detail 2.1); Unit 1 was shutdown due to a failed vacuum breaker surveillance test (Detail 3.3); secondary containment ventilation zones were crosstied (Detail 3.4); inspections were satisfactorily completed on large GE motors (Detail 6.1); review of a potential generic problem with non-essential diesel generator trips found no problems (Detail 6.3); the storage of transient equipment in safety-related areas requires increased management attention (Detail 6.4); and a shift supervisor was relieved of his responsibilities due to inattentiveness (Detail 7.0).

Two violations were identified. One violation involved inadequate corrective action for a nonconformance concerning anti-rotation devices for Anchor Darling globe valves (Detail 6.2). The second violation concerned an inoperable fire door which was not detected on a daily surveillance (Detail 2.2).

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DETAILS

1.0 Followup on Previous Inspection Findings

1.1 (Closed) Unresolved Item (388/83-19-08): Supercritical Postweld Heat Treatment of Weld Repairs on Pacific Southern Foundry Casting Lacks Licensee Justification

The inspector reviewed the licensee's response to this item involving the sequence of weld repair and heat treatment for carbon steel valves furnished by Pacific Valves. A previous review had questioned the fact that the valves were repair welded in the as-cast condition followed by normalizing (1650°F air cool), referred to as Practice A instead of a more common sequence of normalizing followed by weld repair and stress relieving (1100°F - 1200°F), referred to as Practice B. The inspector's concern was that the tensile properties of normalized E7018 weld metal produced by Practice A were generally lower than as-welded or stress relieved E7018 weld metal produced by Practice B, and in some cases, may fall below minimum tensile requirements for carbon steel base metal of 70,000 psi. In this regard the inspector was correct, but on the other hand normalized E7018 weld metal generally exhibits better ductility, particularly impact strength, albeit at the expense of a slightly lower tensile strength. The improved ductility is due to the homogenizing effects of the normalizing treatment. It should be noted that multi-layer E7018 weld metal in the as-welded or stress relieved condition is generally of higher tensile strength than its companion carbon steel base metal of 70,000 psi, and therefore can better tolerate a normalizing postweld heat treatment that tends to reduce tensile strength and hardness. The higher strength weld metal compared to base metal is principally due to the fast cooling rates that are associated with the deposition of multiple layers. It must also be pointed out that Practice B (weld repair after normalizing) is preferred by some foundries and manufacturers because of the dangers of cracking a raw casting. Normalizing reduces the risk of cracking by producing a homogenized structure, free of gross solidification strains. In summary, the decision to select Practice A or Practice B is the manufacturer's/foundry's choice and depends on various factors such as the complexity, grade and size of the casting, the foundry or manufacturer's heat treatment and welding capability, and mechanical property requirements including tensile and impact properties. Both Practices A and B have been used by industry and are acceptable providing the welding requirements of ASME Code Section IX are followed.

The Pacific Valves referred to in this item are considered acceptable on the basis that (1) the vendor had conformed to ASME Code Section III and IX requirements by successfully qualifying a weld procedure utilizing a post-weld/normalizing heat treatment of 1650°F and (2) the practice of weld repair followed by normalizing is not considered unique.

1.2 <u>(Closed) Inspector Followup Item (388/84-41-01): Moisture in HPCI Lube Oil</u>

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 2 First Refueling Outage, the licensee installed PMR's 85-3070 and 85-8036. PMR 85-3070 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 85-8036 installed a lube oil sample connection in the oil line, just upstream of the oil filters. Operations Procedure OP-252-001, High Pressure Coolant Injection, was revised to incorporate a maximum limit of 0.5 percent moisture content in the lube oil.

The inspector verified completion of the modifications and reviewed the revised procedures. Based on discussions with cognizant engineers following a suspected lube oil problem in July 1987, the inspector noted that the Chemistry group continued to take samples directly from the sump rather than using the sample connection. The Technical Group drafted a memo to the Chemistry group to inform them of the new sampling connection. This had not been done upon performance of the modification. The lube oil moisture content was determined to be within specification.

1.3 <u>(Closed) Unresolved Item (387/85-09-04): Followup of Corrective Actions on Indications on In-Vessel Components</u>

In February 1985, during inservice inspections (ISI) in the Unit 1 reactor vessel, crack indications were discovered in a number of components. The most significant indications were discovered on one of four steam dryer support blocks, which is welded to the vessel, and the non-safety-related steam dryer assembly. The licensee prepared NCR's 85-0113 and 85-0117 to document the indications on the dryer and support block respectively, and formed a task force to further evaluate these problems. The lead responsibility for disposition of these issues were transferred to NRR. Regional specialist and NRR representatives were dispatched to the site in April 1985 to observe and review the licensee's activities in the repair and resolution of the defects. The review found the steam dryer and support block repairs acceptable. The review is documented in Inspection Report 50-387/85-13. The unresolved item remained open pending completion of the licensee's final task force report, review of the root cause of the steam dryer cracking, and further inspections planned for the next refueling outage.

Due to uncertainty in the cause of the steam dryer support block failure and the steam dryer cracking, an instrumentation package was installed on the steam dryer by General Electric. The instrumentation remained installed until the Second Refueling Outage which commenced in February 1986. GE collected data from the steam dryer instrumentation during reactor operation from cold conditions to full power at 10 percent intervals. In addition, transient response was recorded due to HPCI, RCIC, and feedwater pump evolutions, safety relief valve lifts, and MSIV closures. The data evaluation was provided to the licensee by GE in the "Susquehanna 1 Steam Dryer Vibration Steady State and Transient Response Final Report" dated Febuary 6, 1986. The reports conclusions were:

-- The seismic block (steam dryer support bracket) at 184° azimuth had stresses well within the tolerance limit. Further damage to the support brackets should not be expected.

-- All the instrumented dryer components, except the unpatched second end bank panel, are structurally adequate to resist the measured vibratory loads during normal operation.

-- The bracket crack both initiated and propogated by fatigue. No evidence of stress corrosion was found.

-- The source of alternating loads which caused the bracket fatigue could not be determined.

The report recommended that one unpatched dryer panel be reinforced since the data indicated the weld may sustain fatigue usage. In response, the licensee prepared Design Change Package (DCP) 85-3148, Steam Dryer Hood Repair, which will be installed if the Inservice Inspection Program identifies the need to complete the repairs.

The licensee also issued a Reactor Vessel Internals In-Service Inspection Task Force Final Report in May 1986. The bracket inspections during the Second Refueling Outage did not identify any relevant indications. Based on the inconclusive steam dryer instrumentation results, the instrumentation was removed. Examinations of the dryer support ring revealed existing and new cracking and unarrested growth of surface IGSCC cracking measured ultrasonically during the First Refueling Outage. These and several other dryer indications were dispositioned "use-as-is" based on an engineering analysis. The engineering analysis determined that the ring was acceptable for at least six more years. These areas are to be reinspected in the next outage to refine the projected life of the dryer.

Based on NRR and Region I review of the licensee's corrective action and the final reports, this item is closed. The monitoring of further In-vessel ISI results will be conducted in accordance with the routine inspection program.

1.4 <u>(Closed) Unresolved Item (387/85-12-01): Review Corrective Action For Offgas System Test Exception Reports</u>

During Unit 1 Startup Test 37.1, in June 1983, several test exception reports (TERs) were issued concerning the Offgas System. TER's 373, 483, and 484 stated that the Offgas Guard Bed 'A' and 'B' inlet flows, temperatures and dewpoints could not be verified to be in accordance with design specifications. The test exceptions were incorporated into Nonconformance Report (NCR) 85-0105.

The high guard bed temperature was determined to be due to the in-line heater controlling temperature too high. Further system testing verified that the actual temperature was correctly maintained around the design setpoint of 65°F.

The offgas flow rate was determined to be excessively high due to an improperly calibrated flow instrument and system inleakage. The vortex-shedder calibration factor supplied by the vendor was based on schedule 40 pipe, however the piping installed was schedule 80 pipe. Testing was performed by a contractor to determine the actual calibration factor. Helium was utilized to detect air inleakage into the condensate system, and numerous leaks were identified and subsequently sealed. The result was an offgas flow of approximately 20 scfm. The licensee is reviewing proposals to replace the vortex-shedding flowmeters with more accurate annubar-type flow elements.

The high dewpoints readings were determined to be due to faulty measurement probes. The existing Panametrics moisture measurement system was found to be highly susceptible to moisture and dirt fouling, causing erroneous readings. The licensee determined that the aluminum oxide sensors are not suitable for use in wet or dirty environments and plans to replace them with an Optical/Condensation type dewpoint hygrometer system. This type of detector was installed on Unit 2 on a trial basis and indicated that the actual dewpoints were approximately 30 to 35°F, while the moisture probes read 65 to 68°F. Therefore, the licensee believes the actual dewpoints have always been within expected design values.

The inspector reviewed the complete NCR package and an Assessment of the Offgas System (SEA-ME-077) performed by a Task Force formed to evaluate and resolve the numerous problems identified with the Offgas System during the Startup program. The inspector had no further questions.

1.5 (Closed) Unresolved Item (387/85-16-02): Circuit Breaker Interruption Impact (CBII) Diagram Deficiencies

On April 21, 1985, with Unit 2 at 100% power and Unit 1 defueled, the licensee attempted unsuccessfully to place the 'A' loop of Emergency Service Water (ESW) in operation. The licensee subsequently found improperly positioned sliding links. The links were repositioned from open to shut, and the ESW 'A' loop was placed in operation. The links had been placed in the open position to support modification work associated with the Unit 1 first refueling outage, but had not been returned to the closed position following completion of the work, thereby preventing the 'A' ESW pump bypass valve from opening. During investigation of the event, the licensee identified controlled drawing deficiencies which led to the load shedding circuit not being included in the blocking and equipment release for modification work.

Inspector review of Circuit Breaker Interruption Impact (CBII) drawings E-16 Sheet 4 and Sheet 8 determined that the specific deficiencies identified were corrected. In addition, checks of drawings E-15 through E-18 determined that all CBII drawings have been updated since this item was identified. The inspector had no further questions.

1.6 (Closed) Unresolved Item (387/85-31-02): 18 Month Lockout Feature Surveillance Procedures Do Not Meet Technical Specification Requirements

In September 1985, the inspector noted that the surveillance test procedures did not adequately functionally test the three main trip relays for each diesel generator start circuit as required by the Technical Specifications. An NQA Audit finding was also issued which addressed the same issue. The plant staff believed that the calibration procedures in use were sufficient for the low lube oil switches and differential relays. Additionally, the staff believed that verification of completion of the diesel generator load reject test without an overspeed trip was sufficient to show that the overspeed trip would not occur when it was not required.

Both the Unit 1 and Unit 2 Technical Specifications required that at least once per 18 months, each of the diesel generators were to be demonstrated operable by verifying that the engine overspeed, generator differential, and low lube oil pressure lockout features prevented diesel generator starting and/or operation only when required. Because the nuclear safety concern is that the diesel generator does not receive a spurious trip in the emergency mode, the licensee determined that the absence of a trip during testing and the completion of the calibrations adequately proved that inadvertent emergency trip signals were not actuated and satisfied the Technical Specification surveillance requirement. The licensee also believed that verification that the trips would actuate when a valid malfunction occurs is important for equipment protection, but is not necessary to ensure plant safety.

The Technical Specification and surveillance test procedures were reviewed by NRC Region I, and NRR, (see Inspection and Enforcement Manual Part 9900) and the surveillance test procedures were found not to satisfy the intent of the Technical Specification requirement because they do not fully demonstrate that these features prevent starting and/or operation when required. The licensee's position that verification that the trips would actuate when a valid malfunction occurred is important for equipment protection, but not necessary to ensure plant safety, is an argument which could be made for a change in the Technical Specification requirement. However, the argument was not acceptable as a basis to disregard an existing Technical Specification which is explicit in its requirements.

The licensee submitted a proposed Technical Specification amendment on April 23, 1986 (PLA-2633). The amendment included a change to Technical Speficiation 4.8.1.1.2.d.13 to more accurately reflect the actual tests performed. The inspector reviewed the current Technical Specifications for both units, and verified the surveillance requirements have been revised.

1.7 <u>(Closed) Unresolved Item (387/85-34-01; 388/85-30-01): Failure to Specify a Nut Torque Value</u>

In November 1985, the inspector determined that the installation instructions for anchoring electrical equipment in the Fifth Diesel Generator project did not specify a torque value for the nut on the anchor bolts, although the manufacturer, Hilti, specified the minimum and maximum torque values to be applied to anchor bolts.

In response, the licensee revised General Specification M-1401, Installation of Mechanical and Electrical Equipment and Piping, to provide some general requirements for anchor bolt installation. The specification now states that all equipment anchor bolt nuts except the drilled-in anchors shall be snug tight unless otherwise specified on engineering drawings or by equipment manufacturer. The snug tight condition is as defined in another specification for structural joints using ASTM A325 or A490 bolts.

The licensee's corrective action is in accordance with normal industry practice and was determined to be acceptable by a regional specialist.

1.8 <u>(Closed) Part 21 Report (387/86-09-02): Anchor Bolts Supplied by Hilti Fastening Systems</u>

On May 9, 1986, a 10 CFR 21 notification was received by the NRC from Dravo Constructors, Inc. (DCI) stating that anchor bolts supplied by Hilti Fastening Systems did not meet the average ultimate tensile loads in certain sizes as published in the vendor design manual. DCI stated in the Part 21 report 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 Part 21 notification only affected bolts installed in the Fifth Diesel Generator Project.

DCI Nonconformance Report No. 462 and PP&L NCR 86-1262 document the corrective action taken by the licensee. Calculations were performed to determine if the currrent installations were acceptable or whether rework was required. The installations requiring rework were completed in June 1987. The details of the licensee's corrective action and the calculations were reviewed by a Region I specialist and found acceptable, as discussed in Inspection Report 50-387/88-10 and 50-388/87-10.

1.9 <u>(Closed) Unresolved Item (388/86-19-02): Missing Incore Dosimetry</u>

In September 1986, the licensee reported that during the Unit 2 Invessel Inspections, it was determined that the material surveillance program RPV neutron dosimeter was not in its holder. The dosimeter was to be removed after the first cycle of operation to verify the fluence-to-thermal power output assumed in the plant design.

The licensee performed an evaluation to determine the safety impact of not having the fluence verification data, and determined that there was no impact. The conclusion was based on the fact that the Unit 1 fluence data was available, and that the other three capsule dosimeters installed will not saturate prior to the first withdrawal. In accordance with ASTM E185-73, the three material surveillance capsules contain dosimeters. The licensee submitted a letter on May 8, 1987 (PLA-2852) to document the action taken. The information was previously reviewed by NRC Region I and NRR, and determined to be acceptable.

The licensee also submitted an FSAR change to correctly reflect the fluence verification method to be utilized.

2.0 Routine Periodic Inspections

2.1 Operational Safety Verification

The inspector toured the control room daily to verify proper manning, access control, adherence to approved procedures, and compliance with LCOs. Instrumentation and recorder traces were observed and the status of control room annunciators was reviewed.

Nuclear Instrument panels and other reactor protection systems were examined. Effluent monitors were reviewed for indications of releases. Panel indications for onsite/offsite emergency power sources were examined for automatic operability. During entry to and egress from the protected area, the inspector observed access control, security boundary integrity, search activities, escorting and badging, and availability of radiation monitoring equipment.

The inspector reviewed shift supervisor, plant control operator and nuclear plant operator logs covering the inspection period. Sampling reviews were made of tagging requests, night orders, the bypass log, Significant Operating Occurrence Reports (SOORs), and QA nonconformance reports. The inspector observed several shift turnovers during the period and routinely attended work planning meetings. In addition, the inspector conducted midnight shift inspections on July 23 and July 30, 1987, and weekend/holiday coverage on July 5, 1987.

On August 7, 1987, the licensee identified that Unit 2 Technical Specification Amendment No. 35 had not been promptly implemented upon receipt. Amendment No. 35 increased the Main Steam Line High Radiation trip setpoint from three times normal background to seven times normal background. The amendment was issued on April 22, 1987, but was not implemented until August 5, 1987. This delayed implementation resulted in a greater than three month period during which the unit operated with the Main Steam Line High Radiation trip setpoint unnecessarily conservative. Since the setpoint remained at the lower value, the specific requirements of the Technical Specifications were met.

The Technical Specification change increasing the setpoint was requested to prevent unwarranted reactor scrams and yet assure that gross cladding failures would be promptly detected. The Unit 1 Technical Specifications had been changed and implemented previously.

The licensee has initiated a Significant Operating Occurrence Report (SOOR 2-87-117) to investigate and resolve the event. The inspector will review the results of the licensee's investigation to determine if a programmatic Technical Specification amendment implementation problem exists. (387/87-12-01)

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 buildings, ESSW pumphouse, the security control center, and the plant perimeter. During these tours, observations were made relative to equipment condition, fire hazards, fire protection, adherence to procedures, radiological controls and conditions, housekeeping, security, tagging of equipment, ongoing maintenance and surveillance and availability of redundant equipment.

On August 13, 1987, the inspector performed the Fire Door Daily Check, Attachment D to operations surveillance procedure SO-100-007, Attachment D to SO-200-007, and Attachment K to SO-100-007, for both reactor buildings and the control structure. During the check, the inspector identified that fire door No. 420 was inoperable. The double door to a 4KV ESS Switchgear Room in the Unit 2 reactor building was not engaging the latch mechanism at the top of the stationary door due to what appeared to be deformation of the door. This constituted a degraded fire barrier. The inspector discussed this with the site fire protection engineer who immediately initiated a Work Authorization to have the door checked and corrected, and an hourly fire watch established. Technical Specification 3.7.7 states that all sealing devices in fire rated assembly penetrations, including fire doors, shall be operable at all times. In addition, Technical Specification 4.7.7.2.a states that each required fire door shall be verified operable by verifying the position of each closed fire door at least once per 24 hours. A review of the completed surveillance from the previous night shift (August 14) indicated that the problem was not identified while performing the surveillance. Since one of the criteria for acceptability per SO-200-007 is that the door latches, the fire door should have been declared inoperable and a fire watch established. The inoperability of the fire door is a violation of Technical Specification 3.7.7 (388/87-12-01).

3.0 Summary of Facility Activities

3.1 Unit 1 Summary

On July 3, a reactor recirculation runback occurred due to an I&C calibration evolution which caused a reactor vessel level reference leg pressure spike combined with a defective level switch on the '1B' feedwater heater. As a result of the runback, reactor power was reduced to 70%. Full power was attained on July 4. Additional troubleshooting found that a failed condensate pump discharge pressure switch existed in the Unit 2 recirculation runback circuit.

On July 6, at 1:40 a.m. a suppression chamber to drywell vacuum breaker failed to cycle during the monthly surveillance test. The unit had been operating at 100% power and commenced a power decrease at 8:00 p.m. on July 8, in preparation for a shutdown as required by the Technical Specification action statement concerning the vacuum breakers. The Unit 1 reactor was manually scrammed from 27 percent power at 1:03 a.m. on July 9, 1987. Following completion of repairs to the vacuum breaker, the unit reached criticality at 5:56 p.m. on July 11, 1987 and returned to full power on July 14 at 4:55 a.m. (See Detail 3.3).

On July 14, at 10:26 a.m., the No. 1 Turbine Control Valve failed full open. The other control valves closed to 31% as designed to maintain proper steam flow to the main turbine. Investigation determined that an LVDT which is used to indicate the valve position had come unthreaded due to a loose lock nut. The valve was repaired on July 16.

On July 28, at 2:30 p.m., the Offgas System isolated in response to a high radiation signal while placing the 'G' condensate demineralizer in service. Main Steam Line Radiation Spikes were also noted. The problem was traced to potential lube oil contamination of the demineralizers during the previous outage.

3.2 Unit 2 Summary

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 July 4 a Reactor Water Cleanup isolation occurred during a check of a temperature indicator for the filter/demineralizer room temperature. The system was immediately restored. (See Detail 4.2.2).

On July 13, at 2:00 a.m., while attempting to enter suppression pool cooling mode on the 'B' RHR loop, flow was not indicated upon opening the suppression pool cooling return valve (2F024B). Investigation found the valve anti-rotation device had loosened. The valve was later repaired. (See Detail 6.2).

3.3 Shutdown Due to Inoperable Vacuum Breaker (Unit 1)

During the performance of surveillance test SO-159-002, Monthly Suppression Chamber to Drywell Vacuum Breaker Valve Check, at 1:40 a.m. on July 6, 1987, vacuum breaker PSV-15704E1 failed to cycle as required. The monthly surveillance test required full cycling and verification of the associated position indication to prove operability of the vacuum breakers. Technical Specification 3.6.4 requires each pair of the suppression chamber-drywell vacuum breakers to be operable and closed. The failed vacuum breaker was confirmed to be closed through the receipt of the amber closed position indication, the lack of dual indication, and lack of receipt of the vacuum breaker open alarm. Each of the three indications noted is associated with its own limit switch. With one of the vacuum breakers inoperable, the Technical Specification required it to be restored to operable status within 72 hours, or to place the unit in Hot Shutdown within the next 12 hours.

The licensee performed troubleshooting of the vacuum breaker and the test circuit to determine the cause of the surveillance test failure but it was not successful. Testing could not trace the problem to an electrical failure in the test circuit of the valve. Continuity checks on the circuit were satisfactory.

At 8:00 p.m. on July 8, reactor power was decreased from 100% in preparation for the required shutdown. The reactor was manually scrammed from 27 percent power at 1:03 a.m. on July 9 and reached Operational Condition 4 at 2:00 p.m. the same day.

The licensee conducted an intensive engineering review prior to the shutdown in order to provide a possible justification for emergency Technical Specification relief. The proposed solution was to defer performance of the monthly surveillance until the next outage which required a containment entry. This was to be based on the acceptability of three pair of the vacuum breakers to mitigate the consequences of a design basis event. However, the engineering calculations could not support the continued operation of the plant.

Five pair of vacuum breakers are installed on downcomers in the wetwell in order to mitigate transient pressure differentials between the drywell and the wetwell. Technical Specification 5.2.2 states that the primary containment is designed for a maximum floor differential pressure of 28 psid downward and 5.5 psid upward. The licensee addressed both the pressure equalization function as well as the bypass leakage ramifications, if it should open and fail to reclose, in their engineering assessment. During calculations of the design basis accident (LOCA) after the ECCS vessel reflood, the calculated pressure differential with only three functioning vacuum breakers (assuming the fourth suffered a single failure) exceeded the design limit of 5.5 psig. Based on this calculation, the emergency Technical Specification change request could not be justified by the licensee, and it was not submitted.

The forced outage work completed included: repair of the failed vacuum breaker; repair of another vacuum breaker position indication; resetting of the HPCI inboard steam isolation valve torque switch and subsequent LLRT; limitorque MOV EQ inspections; drywell sump pump inspections; IRM repairs; and a modification to provide a protective barrier around the Main Steam Line low pressure switches. Repair of the vacuum breaker discovered that the test solenoid valve coil (Circle Seal) was burned and open. This failure would not allow instrument gas to be ported to the test cylinder, thus the valve would not stroke upon receipt of a test signal. The solenoid coil was replaced. The outage work was completed and the unit achieved criticality at 5:56 p.m. on July 11. The unit reached full power on July 14.

The inspector conducted a review of previous Suppression Chamber to Drywell Vacuum Breaker problems to determine the adequacy of the licensee's previous corrective actions. There have been six previous LER's submitted concerning nine vacuum breaker problems. The majority were related to anomalous position indications noted during monthly surveillance testing or post-SRV-lift surveillances. One other unit shutdown (LER 388/84-09) was caused by a faulty position indication. As corrective action, the licensee replaced the cam type limit switches with plunger type switches and added stiffening braces to the limit switch brackets to prevent downward deflection which occurred when the switches operated. One of the failures described in the LERs was caused by a faulty test solenoid valve. (LER 83-0119). During disassembly, the solenoid valve was found to have corroded and rusted internal parts. All of the ten solenoid valves were cleaned and refurbished. In addition, during the Unit 1 startup program (October 1982) a similar failure (burned and open) of the solenoid coil on the same vacuum breaker occurred. In none of the reported events was the vacuum breaker not functional in the event of an accident. All were due to failures in the position indication or the surveillance test circuits.

3.4 Secondary Containment Ventilation Zones Crosstied (Unit 1)

On August 10, 1987 at 2:00 p.m., the licensee discovered that Reactor Building Ventilation Zones I and III had been potentially crosstied from July 30, 1987 to August 10, in violation of Technical Specifications. In order to provide for access from the Central Railroad Bay to the Unit 1 Reactor Building to facilitate transfer of Control Rod Drives, step 3.11.6 of operating procedure OP-134-002, Reactor Building HVAC Zone I and Zone III, was performed at 8:55 p.m. on July 30. Subsequently, the wall separating the Railroad Bay and the Unit 1 Reactor Building 719 elevation was removed. Following the CRD transfers, the wall was reinstalled. On August 10, while restoring the ventilation configuration for the Railroad Bay in accordance with OP-134-002, step 3.11.8, isolation dampers XD-17513 and XD-17514 were found open, when they were required to be closed. With the dampers open, Zone III was crosstied with Zone I during the period the wall was removed.

The railroad access shaft, provided in Unit 1 only, is accessible to Zones I and III through access hatches and doors that are normally kept closed and will not be opened without proper controls to maintain secondary integrity during normal plant operation. Ventilation supply and return ducting to the railroad access shaft is provided with manual isolation dampers to provide for opening the railroad access door after closing the dampers, thus converting the bay to an airlock and retaining secondary containment integrity. Operation of these dampers, railroad access doors and hatches is administratively controlled by operating procedure OP-134-002.

Technical Specification 3.6.5.1 requires that secondary containment integrity be maintained while in Operational Condition 1. In accordance with Technical Specification 1.37 and 4.6.5.1, included in the requirement for secondary containment integrity, is that all secondary containment penetrations required to be closed during accident conditions, including penetrations between zones, are either closed or capable of being closed by an automatic isolation system.

The licensee is investigating the cause of this problem and will report the results in a LER. This item is considered unresolved pending review of the results of the investigation and the corrective action taken. (387/87-12-02).

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

*87-021, Entry Into LCO 3.0.3 to Perform 4KV ESS Surveillances

87-022, Control Structure Chiller Repairs

**87-023, Inoperable Primary Containment Vacuum Breaker Solenoid Valve

Unit 2

*87-008, Reactor Water Cleanup System Isolation on High Room Temperature

* Further discussed in Detail 4.2
** Further discussed in Detail 3.3

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 87-021: Entry Into LCO 3.0.3 to Perform 4KV ESS Bus Degraded Voltage Relay Surveillances (Unit 1)

On June 22, 1987, with Units 1 and 2 operating at 100 percent power, Limiting Condition for Operation (LCO) 3.0.3 was entered and cleared four times on each unit to perform surveillances on the 4.16 KV Engineered Safeguard System (ESS) busses. To perform the monthly degraded voltage channel functional tests on an ESS bus, all degraded voltage protection on the affected bus is taken out of service although the bus remains energized. Technical Specifications require 2 channels of degraded voltage protection per bus, and both must be operable. The loss of both channels of degraded voltage protection was not addressed by the action statement, therefore entry into LCO 3.0.3, requiring a shutdown, was required.

There were 13 other LER's previously submitted which addressed entry into LCO 3.0.3 to perform the Degraded Voltage relay surveillances. On July 2 an approved Technical Specification Amendment for each unit was received which clarified the action statement to address the situation where both channels of degraded voltage protection are inoperable at the same time. This should prevent recurrence of entering LCO 3.0.3 to perform this testing.

4.2.2 LER 87-008: Reactor Water Cleanup System Isolation on High Room Temperature (Unit 2)

On July 4, 1987, a Reactor Water Cleanup (RWCU) System isolation occurred from a room high temperature signal. At the time of the event, operations personnel were checking the RWCU filter demineralizer room temperature reading at a control room panel. The apparent root cause of this event is that the trip setpoint of the temperature instrument that initiated the isolation was set too low for the normal conditions at the instrument location. The temperature instrument which actuated the isolation was labeled "RWCU F/D Room", but the device is actually located in the RWCU penetration room. As part of the corrective action, the licensee temporarily relabled the instrument to reflect the actual location. As an additional temporary measure, the temperature instruments were set at a trip setpoint value at the high end of the allowable range. The licensee plans to perform an evaluation of the temperature leak detection requirements for the RWCU system on both units to ascertain correct temperature instrument setpoints and locations. The licensee is planning to submit a supplemental LER discussing the final corrective actions.

4.3 Review of Periodic and Special Reports

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

The following periodic and special reports were reviewed:

-- Monthly Operating Report - June, 1987, dated July 14, 1987.

-- Monthly Operating Report - July, 1987, dated August 12, 1987.

The above reports were found acceptable.

5.0 Monthly Maintenance Observation

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:

-- Five Year Overhaul of the 'C' Diesel Generator performed from July 8 to August 1.

-- Five Year Overhaul of the 'D' Diesel Generator performed from August 3 to August 15.

No unacceptable conditions were identified.

6.0 NRC Bulletin and Information Notice Followup

6.1 Information Notice No. 87-30: Cracking of Surge Ring Brackets in Large General Electric Company Electric Motors

Information Notice (IN) No. 87-30, "Cracking of Surge Ring Brackets in Large General Electric Company Electric Motors", was issued on July 2, 1987, to alert licensees to a potentially significant safety problem that could result in the loss of safety-related equipment, such as RHR, and Core Spray pumps that are driven by large, vertical electric motors manufactured by General Electric (GE). The licensees were requested to review the information for applicability and consider actions, as appropriate, to preclude a similar problem. GE informed the NRC of this problem on March 24, 1987.

The IN stated that a fatigue failure on the surge ring brackets and cracking in end-turn felt blocks on several GE motors at two reactor plants were discovered during routine motor inspections. Felt blocks are used in large electric motors to keep the windings separated where they loop back at the end of the stator. The blocks are attached to a surge ring that is held in place by L-shaped surge ring brackets welded to the surge ring and bolted to the motor casing. Failure of these surge ring brackets and cracking of the felt blocks allows movement and wear of the end-turns, leading to a reduction in insulation resistance and possible motor failure. In addition, broken pieces of the surge ring bracket may enter the space between the stator and the rotor, resulting in electrical or mechanical motor degradation. The surge ring bracket, a 1-inch-wide by 1/8-inch-thick L-shaped piece of carbon steel, has been breaking at the sharp bend.

Testing conducted at another site showed significant cyclic loading of the bracket when the motor was started, and the bracket was also shown to be subject to vibration during steady state operation. GE recommended that annual inspections be performed until operating experience indicates that this is no longer necessary. The examination is conducted without disassembling the pump motor, using either a boroscope or a mirror inserted through the existing air vents. GE also has recommended a complete disassembly and inspection at 10-year intervals to ensure the continued qualification of the motors.

The inspector discussed the motor bracket problem with the licensee to determine if the information had been received from GE and if appropriate corrective actions had been taken or scheduled. The licensee received formal notification from GE by a letter dated March 18, 1987, which stated that a reportable condition did not exist.

In response to the GE provided information, the licensee with the assistance of a vendor representative, performed boroscope inspections of one core spray pump and one RHR pump on Unit 1 on June 29 and July 1 respectively. The inspections did not identify any evidence of cracking on either the surge ring bracket or felt blocks. The vendor plans to provide a report to the licensee concerning the results of the inspections. The licensee also plans to inspect one emergency service water (ESW) pump, which was also procured from GE. The inspector had no further questions.

6.2 Information Notice No. 83-70: Vibration Induced Valve Failures

On July 13, 1987, at 2:30 p.m., while attempting to enter suppression pool cooling mode on the Unit 2 'B' RHR loop, no flow was indicated upon opening the suppression pool cooling return valve (2F024B). Control room position indication showed the valve to be opening, but the minimum flow valve remained open indicating no flow in the system. The control room dispatched an operator to the valve. With the associated RHR pumps shutdown, the valve cycled properly open and closed. With an RHR pump running, the stem was observed to rotate in place without moving, when attempting to open the valve. The loop was declared inoperable and the other loop of suppression pool cooling was utilized.

Upon further investigation, it was found that the anti-rotation device set screw had loosened sufficiently to allow the stem collar to slide down the stem and the key became displaced. With the key removed, the stem rotated freely and the valve disc would not move. The key and collar were returned to their normal position and the setscrew was retightened using Loctite. The valve was then retested satisfactorily.

Information Notice (IN) No. 83-70, Vibration-Induced Valve Failures, was issued on October 24, 1983 to provide notification of events that resulted in valve failures and system inoperability as a result of normal operational vibration. The IN described several events at other facilities where the valve stem clamp setscrew loosened, allowing the clamp to slide along the stem and the clamp key to fall from its keyway, allowing the motor operator to rotate the stem without moving the valve disc. The setscrew in the stem clamp was believed to have loosened because of normal system vibration. The licensee's concluded that only globe valves manufactured by the Anchor Darling Company were susceptible to vibration failures of this type.

General Electric Company also issued a 10 CFR Part 21 Report on the Anchor Darling valve failures on December 16, 1983. The valve vendor recommended corrective action was to lock the setscrew in place by either staking the stem collar threads, or applying a nuclear grade thread locking compound (Loctite) to the set screw threads.

Supplement 1 to IN 83-70 was issued on March 4, 1985 to provide information on additional valve failures and system inoperability as a result of loose valve stem anti-rotation devices. These additional failures involved valves supplied by companies other than Anchor Darling.

The licensee had performed an evaluation of this generic problem prior to the IN and the GE Part 21 report. Two nonconformance reports (NCR's 82-911 and 82-1071) were written on the subject in 1982. The NCR's were issued due to six valve failures caused by loose anti-rotation devices. The NCR's resulted in Work Authorizations (WA) to correct the deficiencies in 40 Anchor Darling globe valves. The corrective actions taken included spotting the valve stems and Loctiting the set screws. Although General Electric determined the condition to be reportable under 10 CFR Part 21, and at least one other licensee under Part 50.55(e), the licensee determined the failures to be not reportable. The reworks were completed in May 1983. However, all of valves requiring rework were not completed when the NCR's were closed out.

The licensee later identified 14 additional safety-related Anchor Darling globe valves with anti-rotation devices installed. The plant staff was informed of the 14 additional valves requiring rework on October 16, 1984 in a letter from Manager Nuclear Design to the Superintendent of Plant (PLI-36027).

The inspector checked several randomly selected work authorizations to verify that the rework had been performed on the Anchor Darling valves. The inspector also looked at several of the valves noted on the NCR's to verify the current status of the anti-rotation devices.

The inspector noted that the anti-rotation devices on both the Unit 1 and Unit 2 RCIC full flow test line return valves to the CST (HV149F022 and HV249F022) were not secured as required by the Engineering Work Request (EWR 820542) associated with the NCR resolution. EWR 820542 stated that the cap screws should be lockwired to prevent loosening during operation on two piece stem clamps. Neither of the valves have had their stem clamps lockwired. Both of these valves experience vibration during operation, and at least four cases of loose and/or damaged anti-rotation devices have occurred on Unit 2. Review of the associated work documentation determined that Loctite was typically applied to the cap screws, but they were not lockwired. The work instructions also did not require that they be lockwired. In addition, there was little direction given on the torqueing of the cap screws. In several cases a measured torque was not applied. All of the maintenance reviewed occurred after closure of the NCR's related to anti-rotation devices.

The inspector also reviewed maintenance procedure MT-GM-003, Valve Disassembly, Reassembly and Rework. The procedure did not include the additional information and precautions for securing the anti-rotation devices on valve stems as provided in the NCR resolution, EWR, and internal memos. The required corrective action was not adequately factored into the procedures. On July 21, the licensee also identified this procedural deficiency and issued a procedure change which included the instructions for securing the anti-rotation devices.

10 CFR 50 Appendix B Criterion XVI states that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. The measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

Although the licensee correctly identified the generic problem with anti-rotation devices and promptly initiated corrective action to correct the deficiency, it does not appear that it was effectively implemented or complete. The failure to promptly complete the corrective action, in that at least 14 Anchor Darling valves with anti-rotation devices were omitted from the original NCR and not reworked; and to take corrective action to preclude recurrence by including instructions in plant maintenance procedures, is a violation of 10 CFR 50 Appendix B (387/87-12-03; 388/87-12-02).

On August 18, after the completion of the inspection period, the licensee conducted an inspection of the anti-rotation device on the Unit 1 'B' loop RHR Heat Exchanger Bypass Valve (HV151F048B). The inspection found that this valve, included in the list of 14 previously noted, had also not been reworked. In response to the finding by the inspector, the licensee has commenced a thorough review of the status of all 54 Anchor Darling valves affected by this problem. In addition, the licensee is reviewing past Information Notices which had not been previously formally included in the Industry Event Review Program (IERP) for inclusion.

6.3 Region I Temporary Inspection Instruction No. 87-04: Bypass of Non-Essential Diesel Generator Trips

During preoperational testing at a BWR-4, a loss of electrical power resulted in a diesel engine tripping upon manual reenergization of an associated instrument power bus. The cause was attributed to a non-essential diesel engine trip which is bypassed on a loss of coolant accident (LOCA) but not a loss of offsite power (LOOP). Based on inspection followup, the diesel start logic was found to bypass these types of non-essential trips for only the LOCA start signals, but not for LOOP signals.

The inspector conducted a thorough review of the diesel generator start and trip logic to determine whether:

-- the non-essential emergency diesel generator trips are bypassed during either a LOCA or a LOOP transient,

-- the bypass feature is routinely tested to verify that it is implemented for either a LOCA or a LOOP, and

-- the trips are developed such to assure the reliability of operation of the EDG.

The diesel generators at Susquehanna are automatically started in the emergency mode on total loss of power to the 4.16 KV buses of either unit to which the diesel generator is connected, or on a LOCA signal (reactor vessel low level or high drywell pressure). Two redundant control/starting circuits are also provided for each diesel generator.

While supplying loads following an automatic start, each diesel engine and related generator circuit breaker are tripped by protective devices only under the following conditions: engine overspeed; lube oil low pressure; and, generator differential. Following a manual start, the diesel generator is in the test mode and in addition to the emergency trips, eleven other protective devices are provided.

Technical Specification 3.8.1.1 requires that while simulating a loss-of-offsite power in conjunction with an ECCS actuation test signal, all of the automatic diesel generator trips, except engine overspeed, generator differential and engine low lube oil pressure, are verified to be automatically bypassed at least once every 18 months. The non-essential trips are not tested during a LOOP signal alone, but due to the control circuit configuration, this is not significant.

Based on inspector review of the diesel generator start circuit drawings and surveillance test procedures, and discussions with the cognizant engineer, discrepancies similar to those identified at other facilities were not identified.

6.4 Region I Temporary Inspection Instruction No. 87-03: Storage of Transient Equipment In Safety-Related Areas

Region I Temporary Inspection Instruction RI 87-03, Storage of Transient Equipment In Safety-Related Areas, was issued March 5, 1987 to provide guidance for reviewing the storage of transient equipment having the potential to adversely affect safety-related equipment. The objectives of the review were to ascertain the status of licensee administrative controls, determine the proper implementation of administrative controls, identify if deficiencies exist and, where deficiencies exist, assess the licensee corrective action process with respect to NRC Information Notice No. 80-21.

Information Notice No. 80-21 states: "The NRC Systematic Evaluation Program (SEP) reviewers observed that non-seismic Category I ancillary items (dolleys, gas bottles, block and tackle gear, ductwork, etc.) may be located such that they could potentially dislodge, impact, and damage safety-related equipment during an earthquake".

The inspector determined by review of licensee administrative procedures that the licensee has established methods of control for several areas of transient equipment control. These are:

-- AD-QA-503, Housekeeping/Cleanliness Control, which includes small equipment and tools which are used above or inside vessels or components.

-- AD-QA-903, Scaffold Erection Review and Inspection, which specifically controls scaffold sizing and restraints.

-- AD-QA-140, Use and Storage of Combustible/Hazardous Materials, which specifically controls hazardous materials and combustibles.

However, there exists no controlling procedure which addresses in general the storage of transient equipment in safety-related areas.

The inspector questioned the licensee concerning their internal response/actions to Information Notice 80-21. The licensee determined that no response/action had been taken with respect to this notice, but that it had recently been placed in their Industry Events Review Program (IERP) for review by their corporate engineering staff. In addition, the inspector discussed the need for a general procedure to control the storage of transient equipment in safety-related areas.

The inspector toured both units to determine if any controls were used in the placement or restraint of transient equipment in addition to those for which procedural requirements presently exist. The inspector determined that adequate procedural implementation appears to exist for those specific conditions for which procedures have been established. However, the inspector noted many instances in both reactor buildings in which equipment used for various work/activites was not restrained and was located such that it could impact instrument racks, CRD hydraulic control units, and MCC's. For example: a large cart filled with chemical resin bags on 779 foot elevation was located near Unit 1 instrument racks 1C204 and 0C204; a number of 55 gallon metal drums were located near the Control Rod Drive Hydraulic Control Units in both units; a Del-Monox Compressed Air Purification System in each unit was located adjacent to instrument racks 1C002 and 2C002; and an American Water Blaster, two large metal "KNAACK" tool/parts boxes and additional eddy current testing equipment were stored next to MCC 216 on the 683 foot elevation in Unit 2. These items were discussed with licensee management.

This item remains unresolved pending review of the licensee resolution and completed actions. (387/87-12-03)

7.0 Shift Supervisor Relieved of Responsibilities for Inattentiveness

The licensee reported to the NRC on August 10 that a Shift Supervisor had been relieved of his supervisory responsibilities following the results of a preliminary investigation into an allegation that he had been inattentive while on the midnight shift. The allegation was made anonymously in a letter from a plant operator received on August 7 by the manager of the licensee's corporate Nuclear Safety Assessment Group (NSAG).

The licensee's initial review of the allegation, which included interviews with members of the shift supervisor's assigned shift, concluded that the allegation was credible, therefore the individual was removed from his shift responsibilities. The licensee also stated that the individual in question was experiencing personal problems that apparently affected his ability to remain alert on shift. The interviews with other operators determined that some instances had been noted where the shift supervisor was observed with his eyes closed while sitting at his desk in the Shift Supervisor's office, adjacent to the Control Room.

The licensee commenced a formal investigation of the allegation, but believes that it is an isolated case. Increased unannounced inspections of the mightnight shift activities by senior station management, on a daily basis, were instituted. The NSAG also commenced interviews with operators to determine the extent of the problems. Initial review of the event indicates individuals were aware of the inattentiveness of the shift supervisor as early as June 16, 1987.

A management meeting with NRC Region I is planned following completion of the licensee's investigation. The licensee discussed its planned action with NRC Region I management in a conference call on August 10, 1987, and discussed the status of the investigation on August 14. The licensee issued a press release on August 11.

8.0 Management Meetings

On August 24, 1987 the inspector discussed the findings of this inspection with station management. Based on NRC Region I review of this report and discussions held with licensee representatives, it was determined that this report does not contain information subject to 10 CFR 2.790 restrictions.