UNITED STATES NUCLEAR REGULATORY COMMISSION

REGION I

Inspection Report Nos.	50-387/91-04; 50-388/91-04
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:	March 26, 1991 - May 13, 1991
Inspectors:	G. S. Barber, Senior Resident Inspector J. R. Stair, Resident Inspector

Approved By: J. White, Chief, Reactor Projects Section No. 2A, Division of Reactor Projects — 6/6/91 Date

Inspection Summary:

Areas Inspected: Routine inspections were conducted in the following areas: operations, radiological controls, maintenance/surveillance testing, emergency preparedness, security, engineering/technical support, safety assessment/quality verification, and Licensee Event Reports, Significant Operating Occurrence Reports, and Open Item Followup.

Results: During this inspection period, the inspectors found that the licensee's activities were directed toward nuclear and radiation safety. No violations or deviations were identified. An Executive Summary is included and provides an overview of specific inspection findings.

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EXECUTIVE SUMMARY

Susquehanna Inspection Reports

50-387/91-04; 50-388/91-04

March 26, 1991 - May 13, 1991

Operations (71707, 71710)

Operators effectively controlled plant evolutions, and identified plant problems.

An Engineered Safeguards System walkdown was conducted of the Unit 2 Division II Residual Heat Removal System. The system was found to be in the proper ECCS standby alignment. A majority of the discrepancies noted during the inspection were promptly corrected by the licensee.

Radiological Controls (71707)

Individual workers and Health Physics personnel implemented radiological protection program requirements. Periodic observation of the licensee's implementation of the radiological controls program indicated that radiation protection was effective.

The licensee identified a weakness in their control of contaminated oil drums. Several oil drums with low levels of contamination were taken off-site. Corrective actions taken were expedient and comprehensive resulting in specific program improvements.

Maintenance/Surveillance (61726, 62703)

The licensee exercised good control of maintenance and surveillance activities. No scrams or ESF actuations were attributable to maintenance or surveillance activities.

A radioactive spill occurred as a result of uncoupling and removing Control Rod Drive Mechanism (CRDM) 38-31. Approximately 500 gallons of reactor water was spilled in the drywell. This event was initially reviewed in Inspection Report 50-387/91-02. The licensee was eventually able to stop the leak and reinstall the control rod. The repair plans were thorough and reflected good support from the vendor.

Emergency Preparedness (82701)

No emergency preparedness issues emerged during the period.

Security (71707)

Routine observation of protected area access and egress control indicated good control by the licensee.

Engineering/Technical Support (71707, 92720)

While doing a walkdown of the station, the licensee discovered two Agastat relay sockets installed in a Unit 1 LOCA/NON-LOCA load shed circuit which were not properly environmentally qualified in accordance with current criteria. The licensee's initial evaluation, as documented in the associated Non-Conformance Report (NCR), did not provide sufficient detail to support the planned resolution of the matter. Subsequently, the NCR was revised to clarify the background and technical details to support the planned resolution. The licensee's subsequent evaluation of these sockets was comprehensive and timely. The licensee intends to replace the sockets with qualified devices during the next outage.

Safety Assessment/Assurance of Quality (90712, 92700, 92701, 92720, 40500)

A total of 70 Significant Operating Occurrence Reports were reviewed during the period. No unacceptable conditions were identified.

Sixteen open items were reviewed. Fourteen were closed and two were updated. The licensee's evaluation of one of the items (i.e., concerning diesel generator day tank design basis) was incomplete. Slow closure was noted for some EQ open items, however, the licensee has implemented improved management oversight to provide more timely correction of all EQ deficiencies and issues.

The Susquehanna Review Committee reviewed ongoing progress by the licensee in reducing the number and type of outstanding deficiencies. Good progress was noted. The committee demonstrated good critique and self-assessment relative to review of operational activities.

Details

1. SUMMARY OF OPERATIONS

1.1 Inspection Activities

The purpose of this inspection was to assess licensee activities at Susquehanna Steam Electric Station (SSES) as they related to reactor safety and worker radiation protection. Within each inspection area, the inspectors documented the specific purpose of the area under review, the scope of inspection activities and findings, along with appropriate conclusions. This assessment is based on actual observation of licensee activities, interviews with licensee personnel, measurement of radiation levels, independent calculation, and selective review of applicable documents.

Abbreviations are used throughout the text. Attachment 1 provides a listing of these abbreviations.

1.2 Susquehanna Unit 1 Summary

Unit 1 entered the inspection period at 100 percent full power. On April 2, power was reduced to 80 percent in order to replace a faulty "B" reactor feedwater pump seal which allowed oil to leak into the feedwater system. Repairs to the seal were completed and full power was restored on April 4. On April 16, the 3B feedwater heater emergency dump valve failed closed and extraction steam to the 3B, 4B, and 5B feedwater heaters automatically isolated. As a result, operators manually decreased power to 60 percent in order to investigate and effect necessary repairs. Repairs were completed on both the 3B emergency dump valve and the 5B feedwater heater level control valve and the unit returned to full power on April 19. Full power was then maintained throughout the rest of the inspection period. No ESF/RPS actuations occurred in Unit 1 during this period.

1.3 Susquehanna Unit 2 Summary

Unit 2 entered the inspection period in the refueling mode at 18 days into the unit's fourth refueling outage. Major work performed during the period included Residual Heat Removal Service Water (RHRSW) and Emergency Service Water (ESW) modifications and testing, Division 2 Residual Heat Removal (RHR) and Core Spray (CS) valve work and testing; valve work and testing on High Pressure Coolant Injection (HPCI), Reactor Core Isolation Cooling (RCIC), reactor recirculation system, Control Rod Drive (CRD) Hydraulic Control Units, Reactor Water Cleanup (RWCU); battery testing, Main Steam Isolation Valve (MSIV) maintenance, main generator rotor reassembly, reactor vessel Inservice Inspection (ISI), Division 2 4KV bus outages and diesel generator surveillances. Additional major activities accomplished during the period were completion of core reload, CRD friction testing, reactor vessel reassembly, operations leak check and drywell closeout and testing. The unit entered Startup (Condition 2) on May 5, in preparation for its return to power and completion of the refueling outage. Scram time testing was performed on May 6, and Condition 2 reentered on

May 7. HPCI, RCIC and main turbine overspeed testing were completed and the main generator placed on line at 12:20 a.m. on May 9, ending the Unit 2 fourth refueling outage. Power escalation continued. At the end of the inspection period Unit 2 was being operated at approximately 85 percent full power.

No ESF actuations occurred during the period.

2. OPERATIONS

2.1 Inspection Activities

The inspectors verified that the facility was operated safely and in conformance with regulatory requirements. Pennsylvania Power and Light (PP&L) Company management control was evaluated by direct observation of activities, tours of the facility, interviews and discussions with personnel, independent verification of safety system status and Limiting Conditions for Operation, and review of facility records. These inspection activities were conducted in accordance with NRC inspection procedure 71707.

The inspectors performed 26 hours of deep backshift inspections on March 29 from 7:30 a.m. to 12:30 p.m. (both inspectors); April 5 from 2:00 a.m. to 6:00 a.m.; April 19 from 2:00 a.m. to 6:00 a.m.; and April 21 from 7:30 a.m. to 4:15 p.m..

2.2 Inspection Findings and Review of Events

2.2.1 Engineered Safety Feature Walkdown - Unit 2 - "B" and "D" Residual Heat Removal System

On May 1 and 2, the inspector independently verified the operability of the Unit 2 "B" and "D" Residual Heat Removal (RHR) loops. The engineered safety system status verification included the following:

- Confirmation that the system was in its ECCS standby alignment and that any existing discrepancies would not impede its safety function.
- Confirmation that the system check-off lists and operating procedure were consistent with the plant as-built drawings and as-installed configuration.
- Identification of equipment conditions and items that might degrade performance.
- Verification of proper breaker positions at local electrical panels.
- Verification of proper system valve alignment at the control room panel.
- Verification of properly valved and functioning instrumentation.

-- Verification that manual valves were in their proper positions.

-- Verification of good housekeeping in the area of the system equipment.

-- Verification that the monthly system alignment check was consistent with the control room panels.

No major weaknesses were identified. However, a number of minor discrepancies were noted which detracted from otherwise good performance. They included:

-- A 12 foot extension ladder was standing unsecured against one of the RHR pumps.

-- Various maintenance tools and equipment were left unattended in the RHR pump room. There was no work in progress. All planned work was completed.

-- Two portable fire extinguishers were stored in the RHR pump room; and the fire extinguisher monthly checks were not current.

-- A permanently mounted 48 inch flourescent light was damaged with no light bulbs installed.

-- Two air hoses were connected to air lines on one end, but not connected to any equipment on the other end.

-- The RHR valve labels on the valves were found to be consistent with the system drawing. However, the RHR system check-off list did not agree with the RHR valve labels/system drawing in all cases.

The inspector discussed the apparent discrepancies with the licensee on May 1. The inspector also performed a second walkdown on May 2 to verify discrepancy correction. The inspector noted that approximately 90% of all of the discrepancies were corrected except for the RHR valve labeling discrepancies, which the licensee agreed to correct. Notwithstanding that defiency, the inspector determined that the system was properly aligned in accordance with the operating procedure. Based on the review, the inspector concluded that the system was operable and that none of the identified discrepancies would have prevented successful operation.

3. RADIOLOGICAL CONTROLS

3.1 Inspection Activities

PP&L's compliance with the radiological protection program was verified on a periodic basis. These inspection activities were conducted in accordance with NRC inspection procedure 71707.

3.2 Inspection Findings

Observations of radiological controls during maintenance activities and plant tours indicated that workers generally obeyed postings and Radiation Work Permit requirements. No inadequacies were noted.

3.2.1 Poor Control of Contaminated Oil Drums

The licensee collects in-plant waste oil and stores it in drums for processing. The licensee's goal in processing these drums is to remove all traces of water that could have low levels of contamination. The licensee uses settling and decanting to skim the oil off the bottom layer of water found in the drums. Procedures require no remaining evidence of water in the drum as indicated by a red band or spots on a "Kolor Kut" sample indicator. The "Kolor Kut" is a dyed paper indicator that is used to quantify remaining moisture at the bottom of waste oil drums.

The previous standard required no indicated water in the bottom of these drums, but did not specify settling time between samples or the amount of oil to be decanted from each drum containing water. This lack of specification led to the release of three slightly contaminated oil drums from the protected area during January 1991. The drums were moved to the hazardous waste yard (HWY) located outside the protected area, but within the owner controlled area.

During a review of waste oil logs, the licensee noted several entries that indicated a trace amount of water. After further investigation, it appeared that three drums containing traces of water were sent to the hazardous waste yard for processing. These three drums were resampled, found to contain water, and returned to waste oil processing inside the protected area. The level of activity found in these drums was above minimum detectable activity (MDA), but orders of magnitude below the regulatory specification identified in 10 CFR 20, Appendix B. As a conservative measure, the licensee held up all oil decanting, transfer, and shipment activities pending resolution of the problem.

SOOR 1-91-042 was written to document the initial discovery of the problem at 5:31 p.m., February 27. An Event Review Team (ERT) was formed to identify the root cause and to recommend long term corrective action. As a precautionary measure, the bulk oil storage tanks in the hazardous waste yard (HWY) were sampled. No contamination was found. The HWY is within the owner controlled area.

The ERT reviewed the event and extended the investigation to require additional sampling in the HWY. This sampling took place on March 22, and identified six drums with activity levels above MDA. All six of the drums were returned to the plant. One of the drums, containing very small amounts of water was found to have activity above the 10 CFR 20, Appendix B specification for Cobalt-60. The residual water in the drum had an activity of

5.37 E-04 uc/ml, compared to the specification of 3.0 E-05 uc/ml. The licensee submitted a 30 day written report per 10 CFR 20.405.

The ERT completed their review on May 2 and identified a number of causal factors that led to the event, including, failure to follow procedures and inadequate procedures. Specifically, it had become common practice to permit as much as 1 inch of water to remain in drums of waste oil, even though the procedural specification was zero. Further, the procedures were noted as weak since 1) settling time prior to sampling was not specified, 2) pre-sample sparging was allowed, which resulted in an order of magnitude difference between bottom samples and sparged samples, 3) the amount of sludge allowed in the drums was not specified, and 4) no single procedure existed to coordinate the handling, sampling, and transporting of the drums. The licensee is addressing each of these procedure adequacy concerns by revising CH-ER-001, Waste Oil Sampling; and is developing a maintenance procedure which will clearly define waste oil drum ownership, handling, transportation, disposal, and documentation. In addition, personnel involved with drum handling will be trained on the new procedures; and counseled to ensure that procedures are followed.

The inspector reviewed the licensee's corrective action and planned actions to prevent recurrence and noted that the corrective measures appeared to be comprehensive and satisfactory for the circumstances. The inspector had no further questions in this area.

4. MAINTENANCE/SURVEILLANCE

4.1 Maintenance and Surveillance Inspection Activity

On a sampling basis, the inspector observed and/or reviewed selected surveillance and maintenance activities to ensure that specific programmatic elements described below were being met. Details of this review are documented in the following sections.

4.2 Maintenance Observations

The inspector observed and/or reviewed 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, as applicable, 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 quality control hold points were established where required; functional testing was performed prior to declaring the involved component(s) 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 and/or reviews included:

- -- Prefabrication of Heat Trace Panel Circuits for Containment Radiation Monitor Piping in Heat Trace Control Panel HTC-2C291A per WA C10039 on March 29.
- -- Control Rod Drive Hydraulic Control Unit (HCU) Scram Valve Diaphragm Replacement for HCU 3011-126 and 3011-127 per WA P10735.
- -- Control Rod Drive Mechanism 38-31 Removal per WA V03158 on April 5.
- -- Investigation of Residual Heat Removal System Minimum Flow Bypass Control Flow Switch FS E11 1N021A due to the Improper Operation of the Minimum Flow Bypass Valve HV-151-F007A per WA S16525 on April 18.

4.3 Surveillance Observations

The inspector observed and/or reviewed the following surveillance tests to determine that the following criteria, if applicable to the specific test, were met: the test conformed to Technical Specification requirements; administrative approvals and tagouts were obtained before initiating the surveillance; testing was accomplished by qualified personnel in accordance with an approved 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 and/or reviews included:

- -- SO-149-002, Quarterly Residual Heat Removal (RHR) System Flow Verification, performed on April 18.
- -- SE-249-001, Eighteen Month RHR System and Logic Functional Test (Division I), performed on April 19.

4.4 Inspection Findings

The inspector reviewed the listed maintenance and surveillance activities. The review noted that work was properly released before its commencement, systems and components were properly tested before being returned to service, and surveillance and maintenance activities were conducted properly by qualified personnel. Where questionable issues arose, the inspector verified that the licensee took the appropriate action before system/component operability was declared. No unacceptable conditions were identified. The following maintenance activity required followup:

4.4.1 Control Rod Drive Mechanism 38-31 Leakage - Unit 2

Inspection report 50-387/91-02 documented a radioactive spill that occurred as a result of uncoupling and removing Control Rod Drive Mechanism (CRDM) 38-31. Approximately 500 gallons of reactor water was spilled in the drywell. The licensee halted CRDM changeouts until the drywell floor was cleaned up and the leak was redirected to the suppression pool. Two workers were mildly contaminated as a result of getting wet during the CRDM changeout.

The licensee's initial efforts to stop the leak were unsuccessful since the guide tube seal did not stop or reduce the leakage when the drive mechanism was unbolted and lowered. The drive mechanism was, therefore, reinserted and bolted to the flange pending further evaluation.

On April 5, the licensee inserted a specially built plug into the control rod guide tube in an attempt to reduce the leakage, properly seat the CRDM O-rings, and terminate the leakage from the CRDM flange. However, the special plug did not reduce the leakage and was removed. The guide tube seal was then reinserted in the guide tube. The CRDM was removed and a blank flange installed at the CRDM flange in order to terminate leakage from the vessel. The guide tube seal was subsequently removed and the guide tube housing thermal sleeve examined internally by camera in an effort to determine structural integrity and assess any impediments to operation.

The licensee also performed a Technical Safety Assessment (TSA) to ensure that CRD 38-31 could perform its intended function without being affected by the existing leakage. This TSA concluded that the existing leakage and its potential sources did not jeopardize the safety function of the control rod since the pressure boundary would normally include the CRDM, once it was successfully installed. In addition, the licensee noted that the normal surveillance program (scram tests, weekly rod exercising, temperature monitoring) would detect any control rod performance degradation. Consequently, the licensee continued recovery efforts based on the conclusions documented in the TSA.

These efforts included installing CRD 38-31 (a second time), reinstalling O-rings with the GE recommended O-ring spacer plate, and retesting the CRD per TP-055-004 (CRD friction testing, single notch confidence test and scram time test). This testing was initially successful, however a leak developed on April 6. This leak was stopped on April 9, after further work on the sealing surfaces. Following, TP-055-004 was rerun and was satisfactorily completed. All control rods, including CRD 38-31, were stroked, timed, and functionally tested by April 19, with satisfactory results.

The inspector reviewed the licensee's actions taken throughout the resolution of this concern and noted that after the initial attempts to properly seat the rod were unsuccessful, the licensee promptly contacted the vendor for technical support. During the investigation, detailed repair plans were prepared and reviewed by PORC to ensure safety. Repair activities were overseen by the vendor. The CRD reinstallation was eventually successful. Continued monitoring is provided by the ongoing surveillance program. No unusual leakage or operability problems were noted with CRD 38-31 during heatup or subsequent startup. Based on the above, no unacceptable conditions were identified.

4.4.2 Safety-related RTD Calibration Inadequacy

The inspector questioned the licensee on their Resistance Temperature Detector (RTD) calibration practices after problems were noted with the calibration practices used at the James A. Fitzpatrick Nuclear Power Plant (See Inspection Report 50-333/90-09). The TS definition of Calibration specifically requires testing of the sensor, trip functions, as well as the rest of the channel. This definition (TS 1.4) also permits flexibility in completing the calibration, as long as the entire channel is calibrated.

The inspector also noted that many safety related instruments require periodic calibration in accordance with their surveillance requirements. For example, TS 4.3.7.5 requires completion of RTD calibrations for Suppression Chamber air and water temperature every refueling outage. When questioned about these calibrations, the licensee stated that the channels are verified and tested as required, except for the detector itself. The licensee believes that the design of these and other RTDs precludes the ability to calibrate these detectors without damaging them during removal. In addition, the licensee stated that this concern was discussed during initial licensing of both units, and that exceptions were noted and granted by the NRC. This issue will remain unresolved pending review of this justification by the NRC. (UNR 50-387/91-04-01(Common))

5. EMERGENCY PREPAREDNESS

5.1 Inspection Activity

The inspector reviewed licensee event notifications and reporting requirements for events that could have required entry into the emergency plan.

5.2 Inspection Findings

No events were identified that required emergency plan entry. No inadequacies were identified.

6. SECURITY

6.1 Inspection Activity

PP&L's implementation of the physical security program was verified on a periodic basis, including the adequacy of staffing, entry control, alarm stations, and physical boundaries.

These inspection activities were conducted in accordance with NRC inspection procedure 71707.

6.2 Inspection Findings

The inspector reviewed access and egress controls throughout the period. No unacceptable conditions were noted.

7. ENGINEERING/TECHNICAL SUPPORT

7.1 Inspection Activity

The inspector periodically reviewed engineering and technical support activities during this inspection period. The on-site Technical (Tech) section, along with Nuclear Plant Engineering (NPE) in Allentown, provided engineering resolution for problems during the inspection period. The Tech section generally addressed the short term resolution of problems; and NPE scheduled modifications and design changes, as appropriate, to provide long term problem correction. The inspector verified that problem resolutions were thorough and directed to preventing recurrences. In addition, the inspector reviewed short term actions to ensure that the licensee's corrective measures provided reasonable assurance that safe operation could be maintained.

7.2 Inspection Findings

7.2.1 Environmental Qualification Concerns for Certain Agastat Plug-In Relay Sockets

On March 22, the licensee informed the inspector that certain Agastat Plug-In relay sockets (CR0067) for relays K11AX3 and K11BX3 at panels 1C221 and 1C222 in the Unit 1 reactor building were not environmentally qualified for SSES. These relays and their associated sockets are part of the balance of plant (BOP) LOCA load shed circuit and provide the LOCA/NON-LOCA timer input signal as part of the 84 percent undervoltage setpoint in the 4KV bus degraded grid voltage scheme. When either timer times out on sensed undervoltage, nonessential loads on the 13 KV bus are shed to assure adequate power continues to be supplied to the 4.16 KV Emergency (ESS) busses. A failure of these relays during a LOCA with a degraded grid condition could potentially overload the 13 KV bus and prevent adequate power to the A and/or B ESS busses.

However, additional protection for the 4.16 KV ESS busses exists at 65 percent and 20 percent undervoltage for a Loss of Offsite Power (LOOP). If power to the 4.16 KV ESS busses would drop to either of these lower thresholds, they would be tripped off and supplied by the emergency diesel generators. The CR0067 relay sockets were originally installed in their respective cabinets and environmentally qualified as an entire assembly under criteria used during initial construction. The licensee's reevaluation under the current standards indicated that the sockets were not qualified as individual components.

NCR 91-0104 was written to document this condition. The licensee concluded that these relays would continue to perform their function when called upon to do so. This conclusion was based on the fact that, although relay sockets CR0067 were not specifically tested for Susquehanna Steam Electric Station (SSES), very similar material was tested on qualified sockets (ECR0002) for SSES by Wyle Test 48859-1. This test was performed at 224 degrees F for 1176 hours. Although some warpage was experienced, the sockets functioned satisfactorily. In addition, a test was performed on the CR0067 sockets for the Grand Gulf Nuclear Station at 212 degrees F for 3000 hours. The Grand Gulf test was terminated when warpage was noted. The licensee's analysis of the Grand Gulf test conditions to the SSES conditions indicated a qualified life at SSES of 25 years at normal conditions of 118 degrees F, and 100 days of accident time at 142 degrees F.

The licensee's evaluation also indicated that the materials commonly used for these sockets have radiation threshold levels greater than the postulated 40 year accident total integrated dose. The CR0067 sockets have been in place for approximately 9 years of operation at SSES Unit 1. Visual examination indicated that these sockets are in excellent condition and routine periodic testing has shown them to be functioning properly. Based on these considerations, the licensee believes it is reasonable to assume that the CR0067 sockets would satisfactorily perform in the same manner as specifically environmentally qualified ECR0002 sockets.

At the time the licensee identified this problem, replacement of the relay sockets was intended to be performed within 30 days. However, in April, the setpoint for the degraded grid undervoltage setpoint was revised upward to 93 percent. Consequently, manual compensatory measures were implemented for alarm response procedures which require LOOP load shedding of the affected 13 KV busses following a 96.5 percent undervoltage condition. The licensee believes these actions bound the existing degraded grid protection and therefore considers the potential impact of relay failure significantly reduced.

Although the licensee believes the relay sockets are qualifiable, they intend to replace them with ECR0002s at the first opportunity. Walkdowns of both units were performed indicated that these two relay sockets were the only CR0067s used in environmental qualification required applications.

Inspector review of NCR 91-0104 noted that supporting facts initially provided by the licensee's corporate engineering staff disagreed with the plant technical support staff conclusion. This was due to poorly worded and incomplete facts concerning the potential qualifiability of the CR0067 sockets. A discussion with cognizant licensee personnel indicated that the supporting facts included with the NCR needed to be rewritten. The licensee supplied the inspector with rewritten supporting documentation which provided a better understanding of the background information and clarified the supporting facts. Based on the clarifications, the inspector had no further questions relative to the licensee's actions and assessment of the expected performance of the CR0067 sockets. The licensee indicated that replacement would be at the first unit shutdown and no later than the unit's next refueling outage.

The inspector reviewed the licensee's procedures to replace the sockets. The procedures include replacement and testing; and indicate that the licensee is well prepared to make the changes at the first opportunity. Although the information determined by the licensee supports that this is not a significant safety issue, the licensee considers it prudent to replace the nonqualified relays with qualified devices at the first opportunity.

8. SAFETY ASSESSMENT/QUALITY VERIFICATION

8.1 Licensee Event Reports (LER), Significant Operating Occurrence Report (SOORs), and Open Item (OI) Followup

8.1.1 Licensee Event Reports

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

Unit 1

87-033-01 CREOASS Boundary Door Failure Required Entry into T.S. L.C.O. 3.0.3 This revision to LER 87-033, which initially reported entry into LCO 3.0.3 due to the failure of a latching mechanism on a control structure boundary door, is to document the determination that entry into LCO 3.0.3 was required, not voluntary. Further, the revision also indicates that a change to both Unit's TS has been initiated to specify actions for this situation and to preclude inadvertent entry into LCO 3.0.3.

90-030-02 Entries Into Condition 2 Without Completed Surveillances on Unit 1 and Unit 2. This revision of LER 90-030-00 incorporates the Unit 2 shutdown on March 9 to enter the fourth refueling outage. See NRC Inspection Reports 90-25, 90-26, and 91-02 for previous discussions.

90-003-00 Fire Damper Not Installed in Fire Rated Barrier. This LER concerned the discovery that a fire rated damper in the Unit 2 control structure was not installed during construction, and a continuous fire watch was not previously implemented since the licensee was not aware of this condition. The licensee preliminarily determined that the subject damper is not necessary due to insignificant combustible loading on both sides of the barrier and stated that an updated LER with the results of further evaluation and resolution will be provided by June 30, 1991.

91-004-00 ESF Actuations Due to RPS EPA Breakers Spurious Trip. On March 21, a spurious EPA breaker trip caused a momentary power loss to the "A" RPS power distribution panel which led to (1) isolations of the reactor building HVAC Zones I and III, the.RWCU system, and various other PCIS components; and (2) auto initiations of the SGTS and CREOASS. All plant systems and components functioned properly. The EPA breakers were reset and no abnormalities were identified. In addition, all isolation signals were reset within 47 minutes and systems/components returned to their normal positions. The licensee was not able to identify a root cause for the spurious trip. However, the licensee noted a vendor (GE) study (Report EDE-18-0789) performed for the BWR Owners Group to address EPA operational and design issues, is currently under review by P.P.& L. to assess any changes that may be warranted to improve reliability.

91-005-00 Contaminated Waste Oil Drum Found in Hazardous Waste Yard, Outside of Protected Area. This LER discusses the discovery that a 55 gallon waste oil drum stored at the licensee's hazardous waste yard outside the protected area contained a concentration of cobalt-60 greater than the regulatory specifications identified in 10 CFR 20, Appendix B. This event was reviewed in Section 3.2.1 of this report.

Unit 2

89-001-01 MSIV-LCS Valves Inoperable Due to Environmental Qualification Deficiencies. This revision to LER 89-001, which originally discussed the discovery of unqualified motor splices on 3 valves in the MSIV-Leakage Control System (LCS), documented the current status of procedural implementation of inspection criteria and installation information for environmentally qualified wire splices.

91-003-00 Isolation Logic Relay Testing Following Replacement Required Entry into T.S. L.C.O. 3.0.3. This LER documents the necessity of withdrawing from a TS action statement to perform post-rework and post-replacement surveillances on a "C" MSIV isolation logic relay. TS do not presently recognize or allow for the removal of an installed trip signal imposed due to action requirements. However, the TS surveillances must be performed to restore the instrument to operable status. The licensee has committed to pursue a change to their TS to allow removing an installed trip signal for this purpose.

91-005-00 Standby Gas Treatment Fan - Unexpected Start. This LER documented an unexpected Start of the "A" SGTS fan on March 9, due to actuation of the filter train high outlet temperature sensor. Since this was considered an ESF actuation, it was reported per 10 CFR 50.73(a)(2)(iv). Licensee investigation into the event identified some design problems which affected the cooling mode logic. This event was previously reviewed in NRC inspection Report No. 50-387/91-02.

No unacceptable conditions were identified.

8.1.2 Significant Operating Occurrence Reports

SOORs are provided for problem identification and tracking, short and long term corrective actions, and reportability evaluations. The licensee uses SOORs to document and bring to closure problems identified that may not warrant an LER.

The inspectors reviewed the following SOORs during the period to ascertain whether additional followup inspection effort or other NRC response was warranted, corrective action discussed in the licensee's report appeared appropriate, generic issues were assessed, and prompt notification was made, if required.

Unit 1

26 SOORs, inclusive of 1-91-063 through 1-91-097.

Unit 2

44 SOORs, inclusive of 2-91-061 through 2-91-114.

No unacceptable conditions were identified.

8.1.3 Open Item Review

8.1.3.1 (Closed) UNR 50-387/86-27-01 (Common), Lubrication Requirements for the Main Steam Isolation Valve (MSIV) Solenoid Valve Seals

In December 1986, the licensee identified air leakage in two out of four inboard MSIV solenoid valves in Unit 2. The licensee discovered the leakage while cycling the MSIV's closed and open to troubleshoot an unexplained drop in Containment Instrument Gas (CIG) header pressure. An examination of the MSIV solenoid valves determined the root cause for the failure was a breakdown of the E.F. Houghton SAFE 620 lubricant. The lubricant was applied to all MSIV solenoid valve O-rings in Unit 1 and Unit 2. The lubricant had been previously changed from Parker Super-O-Lube to E.F. Houghton SAFE 620 because of deficiencies noted during Environmental Qualification Tests by Wyle Laboratory. Licensee

discussions with the valve vendor following the event verified that the preferred lubricant was Parker Super-O-Lube. A Nonconformance Report was written on the MSIV solenoid manifolds for each Unit. The licensee used a General Electric (GE) test report to conditionally release the MSIV's for operation. All of the Unit 1 and Unit 2 MSIV solenoid valves were reworked and properly lubricated using the Parker Super-O-Lube lubricant.

The inspector reviewed the GE test report, update of the EQ binder, and closeout of the NCR's for the MSIV's. The inspector found that the licensee adequately addressed the original Environmental Qualification Test concern. The inspector also reviewed the program in place to replace and lubricate the MSIV solenoid O-rings and plungers within the interval allowed by the EQ binder. The inspector noted that the maintenance and surveillance (M & S) sheet and Plant Management Information System (PMIS) ensure scheduled replacement prior to exceeding qualified lifetime. Based on these actions, this item is considered closed.

Even though this item is closed, the inspector considers the revision to the EQ binder untimely. EWR #N61259 stated that the revision to the EQ binder (EQEL-78) was forecast for November 1987. The actual EQ binder update was incorporated and approved August 1990. The length of the delay indicates that additional management attention is needed to ensure timely closure of EQ concerns.

8.1.3.2 (Closed) UNR 387/87-12-04 and 387/89-81-02 (Common) Transient Equipment Control in Safety Related Areas

In August 1987, in response to a Regional Temporary Instruction, an NRC inspector reviewed the licensee's administrative procedures for several areas of transient equipment control. The inspector noted there were no procedures which addressed the storage of transient equipment in safety-related areas. The inspector toured both units and noted many instances in both reactor buildings in which transient equipment was not restrained properly and was located such that it could impact safety-related equipment.

In October 1989, an NRC inspector noted transient equipment control inadequacies and scaffold control problems similar to the concerns noted in the August 1987 inspection. The inspector also noted rolling equipment was not secured properly and, therefore, could impact safety-related equipment during a seismic event.

The licensee addressed the transient equipment concerns by writing administrative procedure AD-QA-552, "Mitigating Safety Impact Concerns With Transient Equipment" which was effective on January 2, 1991. The licensee also committed to incorporating training for prcoedure AD-QA-552 into General Employment Training (GET) and GET-Requal. The scaffolding concerns were addressed by revising procedure AD-QA-903, "Scaffold Erection Review Inspection."

The inspector reviewed the new transient equipment control procedure, AD-QA-552 Rev. 0 and noted that the procedure adequately defined transient equipment, how to tag transient

equipment, and where transient equipment should be stored. The inspector conducted a walkdown of the Unit 1 reactor building and the "E" Diesel Generator building to check transient equipment control and scaffold assembly. Except for a few minor discrepancies, transient equipment was found to be adequately tagged and stored; and wheel restraints were used in accordance with procedure AD-QA-552. Scaffolding was adequately erected with the required check-off sheet attached to the scaffolding. The inspector noted good progress, in the control of transient equipment. Minor implementation problems were noted. However, overall implementation improved throughout the inspection period. Based on the above observations, this item is considered closed.

Relative to this matter, the inspector noted that effective resolution of the problem did not occur until the second open item was brought to the licensee's attention. Further management attention is needed to ensure that open item correction is promptly scheduled and implemented.

8.1.3.3 **(Closed) UNR 387/87-17-01 (Common), Quality Assurance Concern for Establishing Witness/Hold Points in Test Procedures**

In November 1987, an NRC inspector identified that there was no mechanism for establishing QA/QC witness and hold points in test procedures (TPs). This practice appeared contrary to the guidance stated in FSAR paragraph 17.2.11 and Administrative Procedure AD-QA-101 sections 7.10 and 8.3. This concern was also similar to the findings identified in Nuclear Quality Assurance (NQA) audit 86-090.

The inspector reviewed operational policy statement, OPS-14, "Control of Inspection and Testing." The review concluded that step 5.1.5 adequately addressed the inspectors original concern for a mechanism to establish witness and hold points in TPs. OPS-14 step 5.1.5 states "If mandatory inspection hold points are required, the specific hold points shall be indicated in appropriate documents to alert the personnel performing the task of the need for inspection."

The inspector also reviewed the licensee's February 1991, NQA response to the original concern stated in NQA Audit 86-090. The licensee has adequately implemented a structured QA Surveillance program. The QA surveillances allow independent personnel from NQA to witness, at random, any and all aspects of particular testing evolutions. The licensee plans to assess future NQA audits to measure their effectiveness in this area. The licensee noted the implemenation of their current QA surveillance program along with the QA audit program they are receiving equivalent independent overview of Post Modification testing. Based on these actions, this item is considered closed.

8.1.3.4 (Closed) UNR 387/88-15-01 (Common), Inoperability of all Four Main Steam Tunnel Delta Temperature Detectors

In August 1988 the licensee reported that the plant had been operating with all eight (four per plant) Main Steam Tunnel Delta Temperature isolation modules miswired, rendering their isolation function inoperable. In this condition, the automatic isolation of the main steam system (as a function of a room temperature increase indicating a steam line break) would not have occurred. Additionally, for Unit 2, the location of the thermocouples used to generate the delta temperature signal was different than FSAR commitments. This condition existed while Unit 1 was (at various times) in modes 1, 2 or 3 (between July 17, 1982 and July 27, 1988); and Unit 2 was (at various times) in modes 1, 2 or 3 (between March 23, 1984 and July 27, 1988). A Notice of Violation for NRC Inspections Report Nos. 50/387/88-15 and 50-388/88-18 was forwarded to the licensee on September 30, 1988, regarding the above.

The licensee's investigation indicated that the mislocation and miswiring occurred during initial installation; and was not discovered or recognized in the startup program or during operation. This was primarily because testing was accomplished using a simulated signal to verify the process, as opposed to a test that would simulate a temperature rise from an actual steam leak.
Further, normal expected values indicative of non-leak conditions were not provided for the Main Steam Line Tunnel Delta Temperature sensors. Additionally, the licensee's evaluation revealed that Steam Leak Detection was considered a subsystem and subsequently was not assigned a dedicated system expert capable of recognizing and resolving problems with the system during startup testing and operation.

The licensee's corrective actions included rewiring the Unit 1 and Unit 2 Main Steam Tunnel Delta Temperature instrumentation such that the sensors were connected to the proper terminals. Other steam leak detectors were inspected to verify proper positioning and normal indication. Mislocated sensors were identified, documented and corrected. Design basis analysis was conducted to assure that steam leak detection setpoints were correct. Because other operable components were available to detect and isolate the Main Steam system during a small Main Steam line break, (such as the Main Steam Tunnel Temperature isolation), the safety significance of the event was considered minimal. Consequently, the licensee has requested a change to the Technical Specifications to delete the Main Steam Tunnel Delta temperature sensing system isolation function. Also, a temperature sensor data collection program was implemented in conjunction with surveillance procedures to provide indication of normal values for the steam tunnel.

The inspector reviewed the licensee's response and corrective actions and determined that actions taken were thorough and adequately addressed concerns identified. Extensive programs were developed which went beyond the original concern. The programs were developed to identify and correct problems with other plant temperature sensors. Further, surveillance procedures were modified to ensure that testing would adequately sensor defects. Based on the above, this issue is closed.

8.1.3.5 (Closed) UNR 387/88-19-01 Reactor Water Cleanup System Flow Indication

During a routine inspection in November 1988, an NRC inspector observed that control room indication of Reactor Water Cleanup System (RWCU) inlet flow was approximately equal to indicated filter-demineralizer outlet flow (approximately 260 gpm). Because inlet flow is approximately 534 degrees and outlet flow is less than 120 degrees the inspector questioned the fact that the volumetric flows were equal. Because of temperature differences (affecting the densities of the fluid), the volumetric flows were expected to differ by about 31 percent. An additional concern was also noted relating to the FSAR design information for the flow element. The FSAR indicated that 200 inches of water differential equated to 400 gpm at 575 degrees. However no temperature correction was made from the design point of 575 degrees to the actual fluid temperature of 534 degrees. This would introduce an error of approximately 6 percent.

The licensee evaluated the inspectors concerns and determined that the flow indications observed were displayed as standardized flows, normalized to 60 degrees. The flows were standardized to allow easy comparison and to allow summation for differential pressure indication and isolation signals without requiring further density compensation. This normalization was accomplished by specifying orifice sizing to obtain 200 inches differential pressure for all piping flows at operating temperatures. Per the licensee, indicated flows at less than normal temperature were higher than actual and, thus, were conservative.

The inspector reviewed the practice of orifice sizing and its effect on a high energy line break (HELB) as analyzed by the FSAR. He determined that the effect of operating temperatures outside the normal range did not increase the consequences of a HELB outside the boundaries analyzed by the FSAR. With a decrease in operating temperature the isolation setpoint is reached more quickly due to an increase in water density. This would cause a greater differential pressure across the orifice and result in the indicated flow being closer to the isolation setpoint. Due to the location of the RWCU inlet piping on the Recirculation piping and Reactor Vessel bottom drain line an increase in RWCU inlet temperature is considered unlikely. Inlet water temperature at these points is affected primarily by feedwater heating, and Reactor Vessel recirculation from the steam separator/dryers. Since the instrumentation causes conservative action with respect to its isolation function, and is a function reactor pressure which is controlled in a tight band, this item is closed.

8.1.3.6 (Closed) UNR 50-388/89-05-01, Determining the Generic Applicability of Containment Isolation Valve Failure to Close as a Result of the Associated Solenoid Valve's Failure - Unit 2

On February 27, 1989, a Division II Primary Containment Isolation (PCI) occurred when the normal power supply to the "B" Reactor Protection System (RPS) instrument bus failed. During verification of plant response, the licensee found that PCI valve HV-28792B2, which is the reactor building chilled water (RBCW) System return line from the "A" Reactor Recirculation Pump motor, did not close. The licensee determined that the cause of the RBCW valve failing to close was due to its air supply solenoid valve (SV-28792B2) failing to actuate on loss of power. The inspector considered the potential generic applicability of the solenoid valve failure.

The licensee's failure analysis, documented in SOOR 2-89-019, addressed the inspectors concerns. The solenoid valve (SOV) was removed in an as-found condition for analysis, inspection, and testing by the licensee and the vendor, ASCO. Testing of the valve at minimum and maximum system operating pressures was unable to repeat the failure. During the visual inspection of the SOV, some foreign material, theorized to be pipe thread sealant and rust-like debris, was found in the valve. Based on the analysis and input from ASCO, the licensee identified no definitive cause. However, the licensee concluded that the SOV's failure to reposition properly on de-energization was caused by an extended period of valve operation, without cycling, in the energized condition at the upper end of the valves normal temperature range and the lower end of the air pressure range. Additionally, the licensee suspected that the difficulty with operation at the limits of valve capability may have been exacerbated by extended periods of low coil voltage and/or a low level of physical contamination.

The licensee has taken action to preclude the build-up of foreign materials in these types of SOVs. The use of oil free filtered air for bench testing solenoid valves and precautions to sparingly apply pipe thread compounds are proceduralized. Several other possible corrective actions were evaluated and discounted (PLIS-34672).

It is noted that the licensee's analysis considered generic applicability of the failure. All other similar ASCO valves located inside the containment were confirmed operable. Only one similar failure of an ASCO valve was identified to have occurred in January 1987, but again no clear cause of failure was identified. The licensee's check of an industry data base (NPRDS) found a very low failure rate for similar ASCO valves.

The inspector reviewed licensee's response and considers the actions taken to be adequate. The licensee's evaluation of the factors contributing to the valves failure was assessed as comprehensive and the evaluation did address potential generic applicability. Based on the above, this item is closed.

8.1.3.7 (Closed) UNR 50-388/89-05-02 Replacement of Motor Splices in the Main Steam Isolation Valve Leakage Control System

During the Unit 2 refueling outage in June 1988, while inspecting MOV connections as a result of a generic industry concern with qualification of MOV connectors, the licensee discovered that motor splices used on three valves in the Main Steam Isolation Valve Leakage Control System (MSIV-LCS) were not environmentally qualified. The splices were connected to the internal windings of the valve dual voltage motors. Immediately after discovery, the licensee replaced the three unqualified splices with environmentally qualified connections and Nuclear Plant Engineering (NPE) was requested to perform an evaluation to determine the operability of the MSIV-LCS subsystem for the period the unqualified splices were installed. After what appeared to be an unduly long period of time, on January 18, 1989, NPE determined that the three valves should be considered to have been inoperable for the period of time the unqualified splices were installed (February 1983 to June 1988). This was based on the fact that no analysis had been performed for the period to confirm valve post LOCA design function operability. It was also determined that the EQ documentation on these type of splices did not exist and that plant procedures did not adequately address the EQ requirements. The licensee concluded however, that the safety significance of this event was small, based on NUREG 1169 which indicates that there is relatively low public risk from MSIV leakage without MSIV-LCS if the containment remains intact.

The licensee determined that the event was reportable per 10 CFR 50.73(a)(2)(v), however failed to make a four-hour notification per 10 CFR 50.72. After discussion with the inspector, the licensee acknowledged the requirement and concurred that they should have made the four-hour notification. The failure to make the notification involved a misinterpretation of the relationship between 10 CFR 50.72 and 10 CFR 50.73 and the licensee indicated an intent to make the report in any future similar situations.

The licensee addressed the issue by, immediately replacing the unqualified splices with EQ splices. Further, procedural changes were made to outline usage of only EQ connections in EQ motor operated valves. Inspection criteria and installation information for wire splices was added to the station Maintenance Department Limitorque inspection and overhaul procedure. An Engineering Discrepancy Management procedure was developed to ensure that potential engineering discrepancies are processed in a timely, systematic manner and that reporting requirements are met.

The inspector reviewed the licensee corrective actions for the event and determined that actions taken have been appropriate and thorough in ensuring that only qualified connectors are used in the future. Additionally, the implementation of the Engineering Discrepancy Management program gives further assurance that Engineering Discrepancies identified will receive proper prioritization and timely review. Based on the above, this item is closed.

8.1.3.8 **(Closed) NV4 50-388/89-13-01, Secondary Containment Ventilation Zones Cross-tied - Unit 2**

In May 1989, the licensee discovered and identified that reactor building ventilation zones I and III were cross-tied in violation of Technical Specification 3.6.5.1. The Unit 1 reactor building, Zone I, can be isolated from the railroad access bay by removable walls which are normally installed and sealed. The Unit 1 and 2 common refueling floor, Zone III, is normally aligned to the railroad access bay through HVAC manual isolation dampers XD-17513 and XD-17514. The Zone I removable walls are allowed to be taken down when the railroad access by 101 door (outside door) and dampers XD-17513 and XD-17514 remain closed. In this instance, both the Unit 1 removable walls and the two dampers were concurrently open. This instance was the third occurrence in which T.S. 3.6.5.1 was violated by cross-tying Zones I and III. It was noted that previous corrective actions, which were administrative in nature, had not precluded the third occurrence. Therefore, the inspector questioned whether other types of corrective actions, such as hardware modifications, might be more effective than further administrative actions.

The licensee addressed the inspector's concern by evaluating several potential plant modifications to determine their effectiveness in reducing the likelihood of recurrence of cross-tying Zones I and III. Through these evaluations, the licensee determined that none of the modifications/changes would absolutely prevent all potential zone cross-ties involving the railroad access shaft. Therefore, the licensee decided to strengthen the existing administrative control to ensure their effectiveness. Additional corrective actions taken to strengthen these controls included developing a standardized equipment release form (ERF) for all railroad access evolutions involving the removal of hatches and removable walls, and the opening of the railroad bay door. This standardized ERF, which has been incorporated into the maintenance and construction planning programs, includes references to the applicable Unit 1 and Unit 2 Tech Specs sections and that the appropriate HVAC operating procedure. Additionally, training was conducted on this event, the use of the standardized ERF and the importance of thorough ERF reviews.

The inspector's review found the licensee's corrective actions to be effective since cross-tying of Zones I and III has not recurred since these improved administrative controls have been implemented. Based on the above, this item is closed.

8.1.3.9 **(Updated) DEV 50-387/89-18-01, Diesel Generator Day Tank Fuel Supply**

During a previous inspection, an NRC inspector noted a deviation from the FSAR commitment for fuel levels in the diesel generator day tanks. The updated FSAR (Revision 40 of Page 9.5-39) indicated that each day tank contains sufficient fuel oil for over two hours of full load continuous diesel generator operation. The same page indicated the fuel requirements at full rated load for diesel generators A,B,C, and to be 272 gallons per hour and diesel generator E to be 550 gallons. However, the inspector found the maximum useable fuel in day tanks A through E to be 376 and 497 gallons respectively, considering the unuseable volume at the bottom of the tank and the fill stop points. Therefore, the useable volume is less than the 2 hour volume committed to in the FSAR. Additionally, the plant operator daily rounds log specified a minimum day tank fuel requirement of 60% and 48% for day tanks A through D, and E, respectively. This was also less than the volume required for two hours of continuous operation.

The inspector reviewed the licensee's response (PLA-3265) to the notice of deviation. The licensee committed to revise Section 9.5.4.2 of the FSAR to clarify the amount of useable fuel capable of being stored in the day tanks. Further, the licensee stated that reference to the useable fuel in the day tank being sufficient for two hours of operation will be deleted since the design basis for the diesel generator run time is based upon useable fuel in the fuel storage tank and not the day tank. The FSAR has been revised to read "The Day Tank Contains fuel oil sufficient for over one hour continuous diesel generator operation at its continuous rated load." A review of the diesel generator fuel oil storage and transfer system design basis, FSAR Section 9.5.4.1, revealed that the system was designed to comply with ANSI standard N195-1976. The ANSI standard requires that the day tank have enough fuel below the fuel transfer pump start lever setpoint to allow the diesel generator to operate for a minimum of 1 hour at 110 percent of its rated capacity. Contrary to the licensee's response (PLA-3265), the design basis for the diesel generator run time is partially based on the day tank. The inspector noted that the change to the FSAR (LDCN 1629) did not consider the day tank requirements of ANSI standard N195-1976. Additionally, it is noted that the electrical distribution system functional inspection (EDSFI) (50-387/90-200 and 50-388/90-200) identified other areas of concern with diesel fuel oil day tank levels. Consequently, the licensee has committed to conduct a thorough review of the day tank calculations and level setpoints. This item will remain open until these matters are resolved and the licensee's review is completed.

8.1.3.10 (Closed) UNR 50-387/89-31-03 (Common), Replacement of Non-Leak-Tight Containment Radiation Monitor (CRM) Blowers

In October 1986, the licensee reported that leakage was found at the containment radiation monitor (CRM) panels. The leakage was identified as coming from the CRM blowers which were not leak tight. This leakage would allow containment atmosphere to leak to the secondary containment. Initially, suitable replacement blowers could not be obtained and the licensee instituted procedure changes to align the units in a safe configuration to prevent post-accident leakage through the CRM panels until suitable replacement blowers were available.

The licensee initiated non-conformance reports (NCRs) 86-0835 and 0836 to identify the non-conforming condition of the blowers. The licensee worked with the vendor, to locate a suitable replacement blower. A replacement blower was identified and approved by a replacement item equivalency evaluation (RIEE No. 88-0287) in November 1988. Engineering change orders (ECO Nos. 89-6118 A through D and 89-6119 A through D) were

developed to install the replacement blowers. Replacement of the blowers was completed in Unit 1 by March 5, 1990, and in Unit 2 by February 10, 1990. The NCRs were closed after installation of qualified CRM blowers.

The inspector reviewed the licensee's response and found the response to be adequate. No concerns were identified during a visual inspection of the sealed CRM blowers. Based on the above, this item is closed.

8.1.3.11 (Closed) UNR 50-387/89-81-03 (Common) and UNR 50-387/90-08-04 (Common), Nonconformance Reports

During a routine inspection in October 1989, an inspector identified a backlog of over 400 unresolved nonconformance reports (NCRs). The inspector raised a concern about the timeliness of resolution of this significant number of unresolved deficiencies and the consequent impact on system operability.

In April 1990, an inspector reviewed the licensee's use of conditional releases for NCRs, the adequacy of NCR dispositions and the timeliness of rework to close some NCRs. After reviewing selected NCRs, the inspector concluded that increased management attention was needed to control the use of conditionally released NCRs. Multiple extentions of disposition dates for conditionally released NCRs and the safety assessments used to document these extensions were of particular concern.

The licensee addressed the inspectors concerns by conducting a comprehensive evaluation of the NCR system and implemented an overall deficiency reduction program, specifically targeted at reducing the number of outstanding NCRs and SOORs. Standards (NDPL 90-003) have been established for deficiency handling. These standards specify prompt operability determinations, limit the time allowed to dispositioning deficiencies, and direct increased management attention to deficiency control programs. The backlog of deficiencies has been reviewed to assess the disposition plan for open each item. It was noted that the number of outstanding NCRs has been reduced from 400 items in October 1989, to the 186 current NCRs as of April 24, 1991. The number of conditionally released NCRs is scheduled to be reduced to 4 items by the completion of the current Unit 2 refueling outage.

The inspector determined that the licensee's increased management attention and changes to the deficiency control program has reduced the backlog open deficiencies. The licensee's policy to provide continued management attention to the overall deficiency reduction program has adequately address the original concerns. Therefore, this item is closed.

8.1.3.12 (Closed) UNR 387/90-08-05 (Common), PP&L Response to an EHC Pressure Regulator Failure

The inspector questioned the licensee regarding their susceptibility to an accident response deficiency noted at Limerick. Taking the mode switch to shutdown too soon after a reactor scram could result in bypassing a required MSIV isolation for a Main Steam Line Break with an EHC regulator. Such action has the potential to cause an uncontrolled reactor depressurization. The licensee's evaluation of this concern with respect to SSES concluded that operators should close bypass valves or MSIVs to terminate the decreasing pressure transient. Therefore, the licensee revised off-normal procedures ON-193 (293) -001, "Turbine EHC System Malfunction" to include these actions.

The inspector reviewed the turbine EHC system malfunction off-normal procedure and noted that the procedure revision adequately addressed the required operator actions. The inspector also noted a comprehensive explanation of the "EHC pressure regulator failure low", in the turbine EHC system malfunction off-normal procedure. Based on the above observations, this item is considered closed.

8.1.3.13 **(Updated) UNR 50-387/90-200-04, Seismic Qualification of 250/125 VDC and 480 VAC Load Center Breakers in Racked-Out Position**

In August 1990, an NRC EDSFI team noted that spare load center breakers were racked-out and questioned their seismic qualification in this position. The licensee reviewed the seismic qualification concern and, consequently, committed to racking-in all spare load center breakers. The licensee also generated system checkoff lists for spare DC and 480 VAC breakers to specify the racked-in position for all spare breakers.

The inspector performed a walkdown of the load center spare breaker checkoff lists. The inspector noted 10 spare breakers that were racked-out even though the current system checkoff list specified the spare breakers normal position as racked-in. The inspector discussed the apparent discrepancies with the licensee and the licensee committed to rack-in the spare breakers.

The inspector discussed this checkoff list (CL) discrepancy with the licensee. The licensee noted that the CLs had been changed, however, the new work practices were not widely known by the operators. The licensee committed to training the operations in the revised CL requirements. This item will remain open until the licensee completes the required training.

8.1.3.14 **(Closed) UNR 50-387/90-200-06 (Common), HPCI Insulation Removal Without Revised HVAC Calculations**

In August 1990, an NRC electrical distribution system functional inspection (EDSFI) team noted that thermal insulation for the Unit 1 and Unit 2 HPCI pump, booster pump and crossover piping had been removed. HVAC calculations had not been revised to consider the added heat input from the pump rooms as a result of the insulation removal.

Subsequent to this finding, the licensee performed a calculation, during the EDSFI inspection, and determined that there was a sufficient margin in the HPCI room coolers to handle the additional heat load. The licensee issued two nonconformance reports to address the concern and reinstalled the Unit 1 HPCI insulation. The Unit 2 HPCI insulation replacement was completed in January 1991.

The inspector performed a walkdown of the Unit 1 and Unit 2 HPCI and RCIC rooms and verified that all thermal insulation was installed for the HPCI and RCIC systems. The inspector also reviewed the original maintenance activity that resulted in missing the reinstallment of the HPCI insulation and considered the missed reinstallation an isolated occurrence. Based on the above, this item is closed.

8.1.4 **Susquehanna Review Committee**

The inspector observed the activities of the Susquehanna Review Committee (SRC) on March 27. The committee reviewed plant activities over two days, March 26 and 27, with major topics including Corrective Action Program Management, TS Amendment requests, various audit findings, and other items specified on the published agenda.

The inspector observed the specific presentations on the corrective action programs (CAP). The licensee's original corrective action program was geared to 10 CFR 50 Appendix B. This program was developed during initial licensing and construction of both Susquehanna units and included, primarily Non-Conformance Reports and NQA Audit Findings. After licensing, the licensee created a new CAP to review reportability of plant events, the Station Operating Occurrence Report (SOOR). This program was created in 1984 to investigate, report and provide corrective action for station events. There have been approximately 4500 SOORs issued since 1984. On August 13, 1990 there were 378 SOORs in the backlog. As of March 1, 1991, there were 271 open SOORs. The licensee has been making good progress reducing the SOOR backlog.

In addition to the SOOR program, the licensee created an Engineering Discrepancy Reporting (EDR) Program to manage the identification, reporting and correction of engineering discrepancies. EDRs are reviewed for significance and reported if required. The licensee has been making good progress reducing the EDR backlog.

The inspector also noted that there was healthy self-criticism of plant activities by the SRC. Two outside consultants are a part of the SRC and bring a fresh perspective to the meetings. During the meeting, they frequently challenged existing perceptions of how activities should be and were conducted, as did, the regular licensee members. The inspector also noted that SRC set high standards in their expectations from the station. A questionable Safety Evaluation Report (SER) was sent back to the station for further rewrite when SRC noted a less than desired safety perspective. The licensee recognizes that the SRC and the Plant Operation Review Committee must set and maintain high standards to ensure that station performance does not erode with time. No unacceptable conditions were identified.

9. MANAGEMENT AND EXIT MEETINGS

9.1 Routine Resident Exit and Periodic Meetings

The inspector discussed the findings of this inspection with station management throughout and at the conclusion of the inspection period. 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.

9.2 Attendance at Management Meetings Conducted By Region Based Inspectors

Dates(s)	Subject	Inspection Report No.	Reporting Inspector
4/19/91	ALARA	91-03	J. Noggle
4/19/91	ISI	91-05	P. Patniak
5/10/91	Engineering	91-06	J. Trapp

ATTACHMENT 1

Abbreviation List

AD	- Administrative Procedure
ADS	- Automatic Depressurization System
ANSI	- American Nuclear Standards Institute
CAC	- Containment Atmosphere Control
CFR	- Code of Federal Regulations
CIG	- Containment Instrument Gas
CRDM	- Control Rod Drive Mechanism
CREOASS	- Control Room Emergency Outside Air Supply System
DG	- Diesel Generator
DX	- Direct Expansion
ECCS	- Emergency Core Cooling System
EDR	- Engineering Discrepancy Report
EP	- Emergency Preparedness
EPA	- Electrical Protection Assembly
ERT	- Event Review Team
ESF	- Engineered Safety Features
ESS	- Engineered Safety System
ESW	- Engineering Service Water
EWR	- Engineering Work Request
FO	- Fuel Oil
FSAR	- Final Safety Analysis Report
ILRT	- Integrated Leak Rate Test
I&C	- Instrumentation and Control
JIO	- Justifications for Interim Operation
LCO	- Limiting Condition for Operation
LER	- Licensee Event Report
LLRT	- Local Leak Rate Test
LOCA	- Loss of Coolant Accident
LOOP	- Loss of Offsite Power
MSIV	- Main Steam Isolation Valve
NCR	- Non Conformance Report
NDI	- Nuclear Department Instruction
NPE	- Nuclear Plant Engineering
NPO	- Nuclear Plant Operator
NQA	- Nuclear Quality Assurance
NRC	- Nuclear Regulatory Commission
OI	- Open Item
PC	- Protective Clothing
PCIS	- Primary Containment Isolation System
PMR	- Plant Modification Request
PORC	- Plant Operations Review Committee
QA	- Quality Assurance

RCIC	- Reactor Core Isolation Cooling
RG	- Regulatory Guide
RHR	- Residual Heat Removal
RHRSW	- Residual Heat Removal Service Water
RPS	- Reactor Protection System
RWCU	- Reactor Water Cleanup
SGTS	- Standby Gas Treatment System
SI	- Surveillance Procedure, Instrumentation and Control
SO	- Surveillance Procedure, Operations
SOOR	- Significant Operating Occurrence Report
SPING	- Sample Particulate, Iodine, and Noble Gas
TS	- Technical Specifications
TSC	- Technical Support Center
WA	- Work Authorization

NRC Form 6
(Substitute)

OUTSTANDING ITEMS FILE
SINGLE DOCKET ENTRY FORM
SUMMARY

Docket/Report No.: 50-387/91-04 Originator: BARBER
50-388/91-04

Report Period: 03/26/91 - 05/13/91 Reviewing Supervisor: J. WHITE

REPORT HOURS/NO. OF FINDINGS (V#/U/F/D)

	Unit1		Unit2		Unit1		Unit2
1. Operations	___	(PLT)	___	7. Engr./Tech. Support	___	(DCM)	___
2. Rad-Con	___	(RCP)	___	8. Safety Asses./ Verification	___	(AOQ)	___
3. Maintenance	___	(MNT)	___	9. Fire Prot./ Housekeeping	___	(FDP)	___
4. Surveillance	___	(SUR)	___	10. Other(Option)	___	(OTH)	___
5. Emerg. Prep.	___	(EPP)	___				
6. Sec/Safeguard	___	(SPP)	___				

TOTAL: ___

Summary Statement (bracket <123 characters): ROUTINE RESIDENT MONTHLY INSPECTION

Checklist: LATER OI Status Updated
_X_ MIP Updated

Out of Division Concurrences:

Section Chief/Individual Report Paragraph/Section Initial/Date

Action:

NRC Form 6 (Cont.)
(Substitute)

OUTSTANDING ITEMS FILE
SINGLE DOCKET ENTRY FORM
(CONTINUED)

Item No.	Type	SALP Code	Area Code	Responsiblity
387/91-04-01	UNR			P2A

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		O

Originator: BARBER

Description (< 123 characters): Resistance Temperature Detector Calibration Inadequacy. (Common)

Item No.	Type	SALP Code	Area Code	Responsiblity
387/86-27-01	UNR			P2A

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: BARBER

Description (< 123 characters): MSIV Air Manifolds Failed Due to Breakdown of Seal Lubricant. (Common)

NRC Form 6 (Cont.)
(Substitute)

OUTSTANDING ITEMS FILE SINGLE DOCKET ENTRY FORM (CONTINUED)

Item No.	Type	SALP Code	Area Code	Responsiblity
387/87-12-04	UNR			P2A

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: STAIR

Description (< 123 characters): Storage of Transient Equipment in Safety-related Areas

Item No.	Type	SALP Code	Area Code	Responsiblity
387/89-81-02	UNR			P2A

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: LYASH

Description (< 123 characters): Scaffolding and Transient Equipment Control Program.

NRC Form 6 (Cont.)
(Substitute)

OUTSTANDING ITEMS FILE
SINGLE DOCKET ENTRY FORM
(CONTINUED)

Item No.	Type	SALP Code	Area Code	Responsiblity
387/87-17-01	UNR			STS

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: EAPEN

Description (<123 characters): QA Verification Requirements in Post-Modification Testing Procedures.

Item No.	Type	SALP Code	Area Code	Responsiblity
387/88-15-01	UNR			P2A

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: BARBER

Description (<123 characters): Inoperability of all Four Main Steam Tunnel Delta Temperature Detectors.

NRC Form 6 (Cont.)
(Substitute)

OUTSTANDING ITEMS FILE
SINGLE DOCKET ENTRY FORM
(CONTINUED)

Item No.	Type	SALP Code	Area Code	Responsiblity
387/88-19-01	UNR			P2A

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: BARBER

Description (<123 characters): Reactor Water Cleanup System Flow Indication.

Item No.	Type	SALP Code	Area Code	Responsiblity
387/88-05-01	UNR			P2A

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: STAIR

Description (<123 characters): Generic Applicability of Containment Isolation Valve Failure to Close.

NRC Form 6 (Cont.)
(Substitute)

OUTSTANDING ITEMS FILE
SINGLE DOCKET ENTRY FORM
(CONTINUED)

Item No.	Type	SALP Code	Area Code	Responsiblity
388/89-05-02	UNR			P2A

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: STAIR

Description (< 123 characters): Replacement of Motor Splices in the Main Steam Isolation Valve Leakage Control System.

Item No.	Type	SALP Code	Area Code	Responsiblity
388/89-13-01	UNR			P2A

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: BARBER

Description (< 123 characters): Ventilation Zones I and III Crosstied in Violation of T.S. 3.6.5.1.

NRC Form 6 (Cont.)
(Substitute)

OUTSTANDING ITEMS FILE
SINGLE DOCKET ENTRY FORM
(CONTINUED)

Item No.	Type	SALP Code	Area Code	Responsiblity
388/89-18-01	DEV			MPS

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		U

Originator: GRAY

Description (< 123 characters): Diesel Generator Day Tank Fuel Supply.

Item No.	Type	SALP Code	Area Code	Responsiblity
387/89-31-03	UNR			OPS

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: BAUNACK

Description (< 123 characters): Replacement of Non-Leak-Tight Containment Radiation Monitor (CRM) Blowers.

NRC Form 6 (Cont.)
(Substitute)

OUTSTANDING ITEMS FILE
SINGLE DOCKET ENTRY FORM
(CONTINUED)

Item No.	Type	SALP Code	Area Code	Responsiblity
387/89-81-03	UNR			P2A

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: LYASH

Description (<123 characters): Nonconformance Reports.

Item No.	Type	SALP Code	Area Code	Responsiblity
387/90-08-04	UNR			P2A

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: BARBER

Description (<123 characters): Use of Conditionally Released NCRs and Their Approach to Problems Impacting Plant Availability Documented in NCRs Unresolved Pending Review. (Common)

OUTSTANDING ITEMS FILE
SINGLE DOCKET ENTRY FORM
(CONTINUED)

Item No.	Type	SALP Code	Area Code	Responsiblity
387/90-08-05	UNR			P2A

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: BARBER

Description (< 123 characters): PP&L Response to an EHC Pressure Regulator Failure - Open

Item No.	Type	SALP Code	Area Code	Responsiblity
387/90-200-04	OTH			PSS

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: JACOBSON

Description (< 123 characters): Questionable Seismic Qualification of 250/125-VDC Load Center Breakers in Racked-Out Position. (Common)

NRC Form 6 (Cont.)
(Substitute)

OUTSTANDING ITEMS FILE
SINGLE DOCKET ENTRY FORM
(CONTINUED)

Item No.	Type	SALP Code	Area Code	Responsiblity
387/90-200-06	UNR			PSS

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status
		C

Originator: JACOBSON

Description (<123 characters): HPCI Pump Thermal Insulation Removal. (Common)

Item No.	Type	SALP Code	Area Code	Responsiblity

Due Date/Ltr.Date*	Date O/M/C//Event Date*	Report Update/Status

Originator:

Description (<123 characters):

NRC Form 766
(Substitute)

U. S. NUCLEAR REGULATORY COMMISSION

Principal Inspector: S. BARBER

Reviewer: J. WHITE

INSPECTOR'S.REPORT

Inspectors: BARBER/STAIR

Docket #/Inspection #/Seq. #:
50-387/91-04 (A)
50-388/91-04 (B)

Licensee/Vendor:

Pennsylvania Power & Light Co.
2 North Ninth Street
Allentown, Pa. 18101

Transaction Type:

X I - Insert
___ M - Modify
___ D - Delete
___ R - Release

Period of Inspection:

From	To
03/26/91	05/13/91

Inspection Performed By: _______ of Region

Organization Code

		Region	Division	Branch
___	Region Office Staff			
X	Resident Inspector(s)			
___	Performance Appr. Team	I	B	B
___	Other			

Regional Action:

___ NRC Form 591
X Regional Office Letter

Type of Activity Conducted (One Only)

X 02-Safety ___ 07-Special ___ 12-Shipment/Export
___ 03-Incident ___ 08-Vendor ___ 13-Import
___ 04-Enf. ___ 09-Mat.Acct. ___ 14-Inquiry
___ 05-Mgmt. Audit ___ 10-Plt.Sec. ___ 15-Investigation

Inspection Findings:

A B C D

X X ______ - Clear
________ - Violation
________ - Deviation
________ - Violation & Deviation

Total No. of Violations and

Letter of Report Transmittal Date

NRC Form 591 or Reg.Ltr. Issued	Report Sent to HQ for Action

Enforcement Conference

Report Contains

Deviations:	Held	2.790 Information
0	NA	NO

NRC Form 766A
(Substitute)

Inspection Report (Cont.):	Docket No./Report No.	Seq.
	05000387/	A
	05000388/	B
		C
		D

Module No.	10 CFR 2 App C Supplement No.	Severity/Deviation 1/2/3/4/5/6/D	Site Related	
				A
				B
				C
				D

Violation or Deviation (<2400 characters):

ATTACHMENT 1

Abbreviation List

AD	- Administrative Procedure
ADS	- Automatic Depressurization System
ANSI	- American Nuclear Standards Institute
CAC	- Containment Atmosphere Control
CFR	- Code of Federal Regulations
CIG	- Containment Instrument Gas
CRDM	- Control Rod Drive Mechanism
CREOASS	- Control Room Emergency Outside Air Supply System
DG	- Diesel Generator
DX	- Direct Expansion
ECCS	- Emergency Core Cooling System
EDR	- Engineering Discrepancy Report
EP	- Emergency Preparedness
EPA	- Electrical Protection Assembly
ERT	- Event Review Team
ESF	- Engineered Safety Features
ESS	- Engineered Safety System
ESW	- Engineering Service Water
EWR	- Engineering Work Request
FO	- Fuel Oil
FSAR	- Final Safety Analysis Report
ILRT	- Integrated Leak Rate Test
I&C	- Instrumentation and Control
JIO	- Justifications for Interim Operation
LCO	- Limiting Condition for Operation
LER	- Licensee Event Report
LLRT	- Local Leak Rate Test
LOCA	- Loss of Coolant Accident
LOOP	- Loss of Offsite Power
MSIV	- Main Steam Isolation Valve
NCR	- Non Conformance Report
NDI	- Nuclear Department Instruction
NPE	- Nuclear Plant Engineering
NPO	- Nuclear Plant Operator
NQA	- Nuclear Quality Assurance
NRC	- Nuclear Regulatory Commission
OI	- Open Item
PC	- Protective Clothing
PCIS	- Primary Containment Isolation System
PMR	- Plant Modification Request
PORC	- Plant Operations Review Committee
QA	- Quality Assurance

RCIC	- Reactor Core Isolation Cooling
RG	- Regulatory Guide
RHR	- Residual Heat Removal
RHRSW	- Residual Heat Removal Service Water
RPS	- Reactor Protection System
RWCU	- Reactor Water Cleanup
SGTS	- Standby Gas Treatment System
SI	- Surveillance Procedure, Instrumentation and Control
SO	- Surveillance Procedure, Operations
SOOR	- Significant Operating Occurrence Report
SPING	- Sample Particulate, Iodine, and Noble Gas
TS	- Technical Specifications
TSC	- Technical Support Center
WA	- Work Authorization