

UNITED STATES NUCLEAR REGULATORY COMMISSION

REGION I

Inspection Report Nos. 50-387/94-25; 50-388/94-26

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: November 22, 1994 - December 31, 1994

Inspectors: M. Banerjee, Senior Resident Inspector, SSES
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Approved By: J. White, Chief 1/25/95
Reactor Projects Section No. 2A, Date

Scope: Resident Inspector safety inspections were performed in the areas of plant operations; maintenance and surveillance; engineering; and plant support. Initiatives selected for inspection were an evaluation of on-line maintenance, and recirculation system vibration testing.

Findings: Performance during this inspection period is summarized in the Executive Summary. Details are provided in the full inspection report.

EXECUTIVE SUMMARY

Susquehanna Inspection Reports

50-387/94-25; 50-388/94-26

November 22, 1994 - December 31, 1994

Operations

The NRC was notified when the licensee recognized that an SRO license renewal application was submitted to NRC without the applicant successfully completing the requalification program requirements. The licensee's review of program administration identified several weaknesses. This item is unresolved. See Section 2.2.

A reportable unplanned reactor power level excursion occurred when a feedwater transient was initiated by a loss of a feedwater flow indicator channel. The feedwater flow indicator channel was lost when one of the 125V DC batteries was put on "equalize" in response to a trouble alarm. The reactor power level went up to 104% for a brief period. The control room operators responded well to the transient. The event identified a potential weakness in licensee's problem resolution in that the control room operators performed the alarm response based on directions from the maintenance organization, without system engineer's involvement or effective efforts to understand the cause of alarm. Section 2.3 pertains.

Maintenance/Surveillance (TI-126)

The licensee performed on-line maintenance on Unit 1 core spray system and various control rod hydraulic control units (HCUs). Although the on-line maintenance program is not completely formalized in a program description or procedures, the licensee appropriately addressed the risk significance of the maintenance activities in safety assessments, and planning/scheduling of activities. Overall, good supervisory oversight and control of the activities were observed. Sections 3.3 and 3.4 pertain.

Engineering/Technical Support

In response to the elevated vibration and noise observed while increasing reactor recirculation system flow during Unit 2 power uprate testing in June 1994, the licensee performed vibration testing of the recirculation system. The testing was conducted in a controlled and deliberate manner following the licensee's procedure for special tests. The test data are being analyzed. See Section 4.1.

Plant Support

An acceptable level of performance and implementation of the radiological controls program were observed. The licensee's goal for 1994 exposure limit of 355 person-rem was exceeded in July 1994 during the Unit 2 outage. Therefore, the licensee set a more realistic goal of 53 person-rem on July 15, 1994 for the remainder of the year. This modified goal was realized when the total exposure since that date came out as 49.1 person-rem. Section 5.2 pertains.

Safety Assessment/Assurance of Quality

The inspectors reviewed and closed one Licensee Event Report (LER), and two unresolved items. Sections 6.1 and 6.2 pertain.



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Details

1. SUMMARY OF FACILITY ACTIVITIES

Susquehanna Unit 1 Summary

The inspection period started on November 22, 1994 with Unit 1 at 100% power. On November 30, 1994 a feedwater transient occurred when the 'B' feedwater flow signal failed downscale. Based on the licensee's analysis, reactor power level exceeded 102% for approximately 21 seconds with a maximum level of 104%. After the transient, the power level was reduced to 98% until the feedwater level control system was returned to three-element control and reactor power returned to 100% on December 1, 1994. Section 2.3 pertains.

On December 2, Unit 1 established a new PP&L continuous generation record of 315 days. Unit 1 continued to operate at 100% power level except for short durations to perform turbine valve testing, and on December 12 and December 14 to replace leaky scram pilot solenoid valves associated with four control rods. Power was reduced to 46% during a down power window on December 16 to perform pre-planned on-line maintenance on four control rod hydraulic control units (HCU) and changeout of recirculation MG set brushes. See Section 3.4 for on-line maintenance on HCU's.

Susquehanna Unit 2 Summary

Unit 2 was at 97% power level at the beginning of the inspection period, following repair of a condenser tube leak which was performed at a reduced power level of 60%. Power was returned to 100% on the same day. Unit 2 continued to operate at 100% power level except for short durations to perform turbine valve testing, control rod sequence exchange and condenser demineralizer flow adjustment. Beginning December 6, 1994, reactor recirculation system flow was increased to collect vibration data in response to an elevated vibration and noise level experienced in June, 1994 during power uprate testing. This test was completed on December 13 and recirculation flow returned to normal. Section 4.1 pertains.

2. PLANT OPERATIONS (71707, 92901, 93702)

2.1 Plant Operations Review

The inspectors observed the conduct of plant operations and independently verified that the licensee operated the plant safely and according to station procedures and regulatory requirements. The inspectors conducted regular tours of the following plant areas:

- Control Room
- Control Structure
- Unit 1 and 2 Reactor Buildings
- Unit 1 and 2 Turbine Buildings
- Engineered Safeguards Service Water Pump House
- Emergency Diesel Generator Bays
- Protected Area Perimeter
- Security Facilities

Control room indications and instrumentation were independently observed by NRC inspectors to verify that plant conditions were in compliance with station operating procedures and Technical Specifications. Alarms received in the



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control room were reviewed and discussed with operators; and operators were found cognizant of control board and plant conditions. Control room and shift manning were in accordance with Technical Specification requirements.

During plant tours, logs and records were reviewed to ensure compliance with station procedures, to determine if entries were correctly made, and to verify correct communication of equipment status. These records included various operating logs, turnover sheets, blocking permits, and bypass logs. The inspector observed plant housekeeping controls including control and storage of flammable material and other potential safety hazards. Posting and control of radiation, high radiation, and contamination areas were appropriate. Workers complied with radiation work permits and appropriately used required personnel monitoring devices.

The inspectors performed 10 hours of backshift and deep backshift inspections during the period. The deep backshift inspections covered licensee activities between 10:00 p.m. and 6:00 a.m. on weekdays, and during weekends and holidays.

2.2 Missed Requalification Quizzes

PP&L notified NRC Region I and initiated a SOOR on November 11, 1994 when they recognized that an SRO license renewal application was submitted to NRC on November 8, 1994 without the applicant successfully completing the requalification program requirements. The program requirements missed were several weekly cycle quizzes given in 1993. The oversight was identified during a routine record review. The applicant immediately completed all of the outstanding quizzes. PP&L initiated an Event Review Team (ERT) to perform a root cause investigation and recommend corrective actions.

PP&L's requalification program requires that, in order to have an active license, an operator shall complete the previous years program requirements satisfactorily. Also, the program requires that both active and inactive licensed individuals must be "current in requalification training". Although criteria for "current in requalification training" was not clearly defined, the program required that training be completed within six weeks after the end of a training cycle. After performing a review of all licensed operator's training records, the ERT determined that a total of six licensed individuals had not completed all requirements of the 1993 program. Two of these individuals were active license holders who had not completed some elements of the 1993 program including simulator scenarios, quizzes, job performance measures and lectures. The Event Review Team determined that the causes of the missed requalification program elements were various program administration weaknesses.

The individuals completed the outstanding items. The licensee determined the delinquent training issue was not widespread and the operators' ability to cope with transients/accidents was maintained. Also, the individuals did successfully complete the annual requalification examination. This item will remain unresolved pending further review of the root causes of the program weaknesses and licensee's corrective actions. (URI 50-387/94-25-01)



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2.3 Feedwater Transient

On November 30, 1994, Unit 1 experienced a feedwater transient while operating at 100% power. Reactor water level increased to 49 inches and reactor power peaked at 104%. Operators entered the appropriate off-normal procedures and restored reactor water level to its normal range.

Prior to the transient, control room operators received a trouble alarm in the 125V DC system. The cause of the trouble alarm was a 125V DC battery monitor. In response to the alarm, the Nuclear Plant Operator (NPO) placed the battery charger in equalize as had been done throughout the week on Unit 2 in response to the same alarm condition. Approximately 15 seconds later the feedwater transient began. The 'C' narrow range reactor water level, 'B' feedwater flow and upset reactor water level instruments failed downscale. The reactor water level control system responded to the indicated, not actual, loss of feedwater flow, by increasing feedwater flow. Consequently, reactor water level and power increased.

The licensee documented the event on SOOR 94-583. A SOOR investigation team was established to determine root causes and needed corrective actions. The licensee determined the event was reportable due to exceeding licensed core thermal power and made the 24 hour NRC notification required by license conditions. The Shift Technical Advisor (STA) and reactor engineering determined core thermal power exceeded 102% for approximately 21 seconds with a maximum level of 104%. The transient duration was approximately 153 seconds and core thermal power stabilized at 100.3%. Operators reduced reactor recirculation flow to reduce core thermal power below 100%. Reactor Engineering concluded there were no thermal or preconditioning limits exceeded and the transient was bounded by the previously analyzed feedwater controller failure. The average power level over the eight hour shift remained below 100%.

The licensee determined the initiating event was placing the associated battery charger in equalize. Operators performed this action based on similar Unit 2 alarms. The electrical maintenance organization, after troubleshooting the Unit 2 alarms, had advised the operators to place the battery charger in equalize to reset the alarm. Although the alarm response procedure provided no such guidance, the recommendation was extended to Unit 1 without further review. Upon further troubleshooting, electrical maintenance found the battery monitor alarm setpoint drifted from 1.32 volts to .3 volts. Electrical maintenance observed the setpoint drift had been happening on all 125V DC battery monitors since setpoint change E91-1022 was implemented during the 3rd Quarter of 1994. No actual battery cell problems existed.

Nuclear System Engineering (NSE) found that two DC circuits in the reactor water level control system which require surge (arc) suppression had utilized a non-standard method consisting of a Zener diode across DC relay coils for surge suppression. Since the installed Zener diodes had an avalanche voltage of 130V, when the 143V DC equalize charge was applied, the excess voltage was dissipated through the diode heat sink. Licensee's investigation found one



Zener diode was loose, and postulated the heat sink could not dissipate the heat generated by the voltage drop. Consequently, diode shorting caused the circuit protection fuses (3 amp) to blow.

PP&L found this design deficiency was recognized by GE during original plant construction. GE implemented a design change to install a 600V diode during Unit 2 construction to correct the design problem. GE also issued a change for implementation on Unit 1 which was in operation at that time. However, this Unit 1 change was not accomplished by PP&L and Unit 2 drawings were never updated. The investigation was unable to determine the cause for the deficiency. The licensee determined there were no previous similar occurrences.

As immediate corrective actions, the licensee replaced the blown fuses and Zener diode, and checked satisfactory performance of the circuit. Design change packages were initiated to install the diode design improvement by March 31, 1994, and change the diode symbol on the drawings. The 125V DC battery system was yellow tagged to not take battery chargers to "EQUALIZE" until design change to install the correct diode is implemented. Electrical Maintenance instituted standing work orders to investigate 125V DC battery trouble alarms prior to instructing operations to "EQUALIZE". The feedwater control was moved to the 'A' control circuit which is powered from an AC supply until the diode design change is implemented on the 'B' (DC) circuit. Review of the GE design change lists revealed that all Field Deviation Design Requests (FDDR's) were consecutively listed with this one exception. The licensee concluded the "missed" design change was an isolated case.

As corrective actions to prevent recurrence, the licensee is further reviewing the feedwater control system to evaluate the preferred feedwater control channel. The 125V DC battery monitor alarm responses and battery monitor setpoint drift concerns are being further reviewed to determine needed corrective action. Similar circuits that use diodes for surge (arc) suppression across DC relay coils are being reviewed for proper application. Estimated completion date is February 28, 1995. The simulator response for the subject transient regarding peak reactor water level was 43 inches, i.e., 6 inches lower than experienced during the actual transient (49 inches). The simulator model is being revised with an estimated completion date of June 30, 1995.

The inspector found operators responded well to the plant transient. Systems performed per design. Previous operator training utilizing the simulator for this type of reactor water level control system failure proved valuable during the event. The involved operators displayed good discipline and judgment in allowing the plant to respond automatically to the failure rather than attempting to manually manipulate the plant.

The inspector agreed with the licensee's peak power determination and reactor engineering assessment of core response. The SOOR evaluation was focused on determining corrective actions and action to prevent recurrence for the reactor water level control system hardware failure. Although separate from the diode application issue, the inspector was concerned that operations and electrical maintenance response to repeated battery monitor alarms was focused



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on clearing the alarm rather than understanding why the alarm condition was present and correcting the cause. The electrical maintenance organization knew about the alarm setpoint drift following the alarm setpoint change, but did not pursue resolution of the issue with system engineering. Also, when the same alarm came in on Unit 1, on November 30, 1994, the established formal process for investigation and troubleshooting was not used. Thus, a remedy was prescribed without reviewing its total impact. The SOOR resolution did not address these human performance issues. SOOR resolution also did not fully explore why the Unit 2 drawings were not updated to reflect the 600V diode installation. The licensee's new deficiency management system is expected to enhance resolution of human performance issues. To strengthen interface between maintenance and systems engineering, licensee management is clarifying their expectation on communication. The licensee is further reviewing the operations and maintenance interface to address the informality of the process used to respond to the battery monitor alarm. This item will remain unresolved pending completion of this review (URI 50-387/94-25-02).

3. MAINTENANCE AND SURVEILLANCE (62703, 61726, 92902)

3.1 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.

Maintenance observations and/or reviews included:

- WA 34014, Inspect 'A' EDG 5R Cylinder Head Inserts to Assess Results of New Corrosion Inhibition, dated November 22, 1994.
- WA 43015, 'A' Loop Core Spray Minimum Flow (F031A) Votes Test, dated December 5, 1994.
- WA 44172, Investigate Minor Steam Leak Unit 1 HPCI Turbine Control Valve, dated December 15, 1994.

Based on an inspection of the above activities, on a sample basis, against the items specified above, the inspectors concluded that the licensee's program was acceptable.



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3.2 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.

Surveillance observations and/or reviews included:

- SO-149-002, Quarterly RHR System Flow Verification, dated November 23, 1994.
- SO-250-002, Quarterly RCIC Flow Verification, dated December 1, 1994.
- SO-152-002, HPCI Quarterly Flow Verification, dated December 15, 1994.

Based on an inspection of the above activities, on a sample basis, against the items specified above, the inspectors concluded that the licensee's program was acceptable.

3.3 On-line Maintenance (TI 2515-126)

The inspector reviewed the licensee's program for control of on-line maintenance, using NRC Temporary Instruction 2515/126, Evaluation of On-line Maintenance, as guidance. The licensee's general policy for work management at SSES is contained in the Tactics for Excellence through Accountable Management ("TEAM") manual. The guidelines for schedule development, review and implementation of work at power operation, planned down power, unplanned short outages and refueling outages are provided in this manual.

The TEAM manual addresses voluntary removal of safety equipment from service to perform surveillances, and needed maintenance and testing that enhances system reliability and benefit the station goal of maximum safe generation. The risk is minimized by establishing guidelines that impose restrictions on system operating modes and limit system out of service time. The station policy requires such work to be done within the constraints of plant Technical Specification and the Final Safety Analysis Report per the TEAM Manual. The work windows are generally limited to a 24 hour duration and work is performed on only one division of a safety system. Licensee maintains a long-term schedule for these work windows.

The licensee extended the above policy to perform on-line maintenance outages which are typically scheduled around the preplanned 24 hour window or other opportune time, such as a prescheduled down power. The scheduling of the work window and scoping are done by the scheduling unit coordinator in coordination

with operations, nuclear systems engineering, and maintenance, and reviewed by station management. A safety assessment is performed by plant system engineering or corporate engineering (Nuclear Technology). In this process, other prescheduled work during the on-line maintenance work window is reviewed to ensure risk significant combinations of inoperable equipment are eliminated. Currently the licensee performs a PRA-based risk analysis, on an as-needed basis. Component and system dependencies are addressed in this analysis to restrict activities involving other systems that are needed for accident mitigation or have a potential for accident or transient initiation.

The licensee's policy is to limit the scope of work such that the scheduled work could be completed well within the technical specification allowed outage time. The licensee monitors the safety systems availability as a performance indicator, and reported they are, in general, well above the INPO goal.

The inspector noted that although work is being performed utilizing the guidance in the TEAM Manual, the licensee's current process for on-line maintenance is not formalized by plant procedures or completely addressed in the TEAM Manual. The licensee indicated that a formal program guidance including a revision of the TEAM Manual and the required procedures are being developed and are scheduled for completion after the upcoming Unit 1 refueling outage.

The inspector reviewed the licensee's schedule for Unit 1 on-line maintenance preceding the upcoming refueling outage in March 1995, and two current examples of on-line planned maintenance during the inspection period. The first involved a four day work window for core spray Division I valves, where the scope of the work also involved 'C' emergency diesel generator monthly surveillance run, and an 8 to 12 hour work window to perform preventive maintenance on standby liquid control system pumps and valves and the quarterly flow surveillance. The second planned maintenance involved a 24 hour work window for four control rod hydraulic control units (HCU). This work window coincided with prescheduled down power that enabled scram time testing following the HCU work. The licensee plans to continue maintenance on HCUs, a few at a time, during full power operation until the upcoming refueling outage.

The inspector reviewed licensee's safety assessment for the two system outages. The safety assessment for core spray Division I outage appropriately addressed the risk significance of the total scope of work planned for the outages window including work on other systems, and discussed the actions designed to reduce risk. Changes to core damage and containment failure frequency for transients, LOCA and ATWS events were found to be minimal. Risk of initiating events such as a LOCA or a plant trip from planned surveillance testing was qualitatively assessed to prevent increase of risk. The inspector noted that the safety assessment did not address the risk significance of the existing degraded or inoperable equipment. Upon inspectors questions, the licensee indicated that system engineering had completed a review of equipment status to ensure that it did not pose an undue risk of initiating an event. This review, however, was not documented. The control room shift personnel



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were briefed about the core spray safety assessment by operations management. The licensee is currently revising their safety assessment procedure to address event initiators.

Following the plant TS, the HCU work was performed with four control rods fully inserted and hydraulically disarmed to prevent movement. Other control rods were repositioned to maintain full power. As the four control rods were fully inserted during maintenance, scram of these rods was assured, and the licensee's safety analysis concluded that because only one control rod is withdrawn at a time, the bounding FSAR analysis for the rod withdrawal error at power event was not affected. To ensure minimal impact on reactivity control systems, the standby liquid control system was required to be maintained operable at all times during the HCU outage. The licensee also evaluated the effect of water accumulator removal on structural integrity of the remaining HCUs and determined that the removal had no impact. Possible backleakage through the single isolation valve during maintenance was not a concern as a 1982 analysis indicated that a control rod drive system leakage of 412 gpm into the reactor building during a LOCA will not exceed the 10 CFR Part 100 dose limits. See Section 3.4 for HCU maintenance observation.

The inspector concluded that the licensee appropriately addressed risk significance of performing on-line maintenance. The planning and scheduling of the activities endorsed appropriate risk perspective. The operations and maintenance personnel involved in the activities were found to be aware of the appropriate priorities. Systems engineering provided good oversight and support of the activities to ensure questions raised during the maintenance activities are properly resolved. Overall, scheduling maintenance outside the refueling outage resulted in improved supervisory oversight and attention by the support groups. PP&L remains to formalize the process by a program description and procedure updates.

3.4 HCU On-line Maintenance Observation

On December 16, 1994, the licensee performed the first control rod drive (CRD) hydraulic control unit (HCU) maintenance at power. Four HCUs (Nos. 38-39, 38-23, 22-23, and 22-39), two from the south bank and two from the north bank, were selected for maintenance. The scram pilot solenoid valves, and the scram inlet and outlet valve diaphragms were replaced on all four HCUs. Additionally, the water accumulator on HCU 22-39 was replaced, and bent SRI switches were replaced on HCU 38-23 and 38-39.

Maintenance engineering, Nuclear systems engineering, construction and training personnel were involved in developing the on-line HCU maintenance plan. In addition to the four HCUs, the licensee will perform on-line maintenance on 37 additional HCUs prior to the upcoming Unit 1 outage. The licensee has developed an HCU task certification program that used a functional HCU mock-up skid for hands on training. This training was administered to eight construction personnel.

The inspector observed parts of the HCU on-line maintenance performed under the following work authorizations:



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- WA 47341, Rework/replace scram pilot solenoid valve for HCU 22-23, dated November 17, 1994.
- WA 47342, Rework/replace scram pilot solenoid valve for HCU 22-39, dated November 17, 1994.
- WA 47343, Rework/replace scram pilot solenoid valve for HCU 38-23, dated November 17, 1994.
- WA 47344, Rework/replace scram pilot solenoid valve for HCU 38-39, dated November 17, 1994.
- WA 44262, Replace accumulator for HCU 22-39, dated October 6, 1994.
- WA 44858, Scram valve diaphragm replacement for HCU 22-23, dated October 7, 1994.
- WA 44866, Scram valve diaphragm replacement for HCU 22-39, dated October 7, 1994.
- WA 44877, Scram valve diaphragm replacement for HCU 38-39, dated October 7, 1994.
- WA 44884, Scram valve diaphragm replacement for HCU 38-23, dated October 7, 1994.

The inspector also attended the licensee's critique. The critique identified items for schedule improvement, better coordination between the work groups and operations, improved communication, parts staging and Health Physics (HP) control.

The inspector noted that the work was performed under appropriate oversight and supervision by maintenance and QC. Nuclear systems engineering provided excellent oversight and support. Radiation protection measures were appropriate. The equipment status was controlled by operations personnel. Appropriate cleanliness controls were taken and temporary covers were installed on open pipe ends after removal of the water accumulator. The work was completed close to the scheduled time.

The inspector concluded that the control and management of the on-line HCU maintenance was effective, and the licensee's critique was thorough and effective in identifying items for coordination, communication and schedule improvements.

4. ENGINEERING (71707, 37551, 92903)

4.1 Reactor Recirculation System Vibration Testing

During the current inspection period, PP&L performed vibration testing of the Unit 2 reactor recirculation system. Previously in June 1994, the licensee experienced elevated vibration and noise levels while increasing reactor



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recirculation system flow during power uprate testing. NRC Inspection Report 50-387/94-11 documented the vibration event.

Nuclear System Engineering (NSE) and the Operations Department performed the testing in accordance with the Plant Operations Review Committee (PORC) approved test procedure TP-264-021, Reactor Recirculation Hydraulic Response Evaluation. The test was designated a special infrequent complex test/evolution (SICT/E) per NDAP-QA-0320 which requires the test be conducted using special administrative controls.

The testing was performed between December 6 and December 15, 1994. The test procedure consisted of increasing reactor recirculation flow and recording vibration and noise data at various locations with reactor recirculation pump speeds both matched and mismatched at various flow rates between 103 million lbm/hr and 108 million lbm/hr. The testing indicated that as flow was increased vibration and noise levels showed a corresponding increase. NSE concluded preliminarily that noise and vibration levels were consistent with that found during the June 1994 testing. The licensee concluded the noise and vibration were indicative of the vane passing phenomena. A General Electric (GE) representative observed portions of the test. The licensee is reviewing and analyzing the data collected during the test procedure. Pending final evaluation and analysis the licensee is maintaining administrative limits on recirculation pump speed imposed following the June 1994 testing.

The inspectors observed portions of the testing from both the control room and the plant. The testing was conducted in a controlled and deliberate manner per NDAP-QA-0320 requirements. Individuals involved with the test were knowledgeable and qualified. The inspector observed the Special Infrequent or Complex Test/Evolution (SICT/E) briefing for the test evolution. The briefing was conducted in accordance with the NDAP-QA-0320 guidelines. The licensee decision to shorten the test procedure duration when the phenomenon was observed was considered prudent. The licensee will inform the NRC of its evaluation and analysis when completed. The NRC will continue to assess the licensee's resolution of this matter as well as evaluate the potential generic implications of this issue.

5. PLANT SUPPORT (71750, 71707, 92904)

5.1 Radiological and Chemistry Controls

During routine tours of both units, the inspectors observed the implementation of selected portions of PP&L's radiological controls program to ensure: the utilization and compliance with radiological work permits (RWPs); detailed descriptions of radiological conditions; and personnel adherence to RWP requirements. The inspectors observed adequate controls of access to various radiologically controlled areas and use of personnel monitors and frisking methods upon exit from these areas. Posting and control of radiation contamination areas, contaminated areas and hot spots, and labelling and control of containers holding radioactive materials were verified to be in accordance with PP&L procedures. Health Physics technician control and



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monitoring of these activities was satisfactory. Overall, the inspector observed an acceptable level of performance and implementation of the radiological controls program.

5.2 Yearly Exposure Goal

The PP&L yearly exposure goal for the two unit plant site in 1994 was 355 person-rem. However, during the Unit 2 outage, the licensee exceeded the goal. A new goal of 53 person-rem was set for the remainder of the year beginning July 15, 1994. The licensee met this goal with the actual exposure of 49.1 person-rem. The 1994 total was 442.1 person-rem. The licensee attributes the result to a more realistic projection of the work and related dose.

6. SAFETY ASSESSMENT/QUALITY VERIFICATION (40500, 90700, 90712, 92700)

6.1 Open Item (OI) Followup

(Closed) URI 92-13-01, Lack of Documents for Maintenance Planners

This unresolved item involved a lack of clearly defined and approved documentation for maintenance planners upon which to base the post-maintenance testing (PMT) of ASME Code valves, as well as insufficient training of the planners.

The inspector reviewed and discussed, with members of the PP&L staff, the maintenance procedures that delineate the PMT requirements for the ASME code valves. Procedure NDAP-QA-0423, Rev. 3, Station Pump and Valve Testing Program, identifies the ASME Section XI pumps and valves and sets forth the administrative controls necessary for implementation of the testing program. The document that defines the method for determining PMT requirements is Maintenance Instruction MI-PS-008, Revision 3, "Post-Maintenance Testing Guide." Attachment B of this document is a flow chart that directs maintenance planners to procedure NDAP-QA-0423. Initial training of the subject maintenance planners was held on September 10, 1992, as documented in the attendance roster of the same date. The planners were instructed in the proper method for determining ASME pump and valve PMT requirements and were informed that procedure NDAP-QA-0423 is the approved method to determine the test requirements.

Prior to the training session, the maintenance planners were using a "Maintenance Component Matrix," which is an off-line computer-developed matrix, to specify testing for ASME Section XI, IWV Categories A and B valves. The September 1992 training emphasized the fact that this Matrix could not be used alone without checking NDAP-QA-0423. It is important to note that a new procedure, MT-AD-522, revision 2, "Rework, Repair and Replacement of ASME Code Components," currently covers the role of the Matrix. In fact, the reference to the Matrix in MI-PS-008 is being considered for deletion in the next revision of the MI. MT-AD-522 is a complete and approved document and is used for the purpose of defining required PMT and examination that is necessary to satisfy the requirements of the applicable Section of the ASME Code. Section 6.4 of this procedure is a summary of post-maintenance examination/testing as

required by the ASME Code. In addition, this section also states that specific requirements are normally specified in the Work Authorizing Document Package. Training of maintenance planners in the document was conducted accordingly. Therefore, this item is considered to be resolved.

(Closed) Unresolved Item 91-04-01, Resistance Temperature Detector Calibration Inadequacy (Common)

This unresolved item was left open pending review by NRC of licensee's justification of not including the resistance temperature detectors (RTDs) in channel calibration.

The RTDs are not included in channel calibration because the design precludes removal from the installed location without damaging the RTD. Since the unresolved item was open, technical specification amendments were approved by the NRC that involved a change to the definition of channel calibration. The amendment (No. 133 for Unit 1 and No. 102 for Unit 2) allowed channel calibration of RTDs and thermocouples to consist of an in-place qualitative assessment of the sensor behavior and normal calibration of the remaining channel.

The inspector reviewed the SSES procedures for periodic calibration of RTDs and thermocouples on a sample basis and concluded that they contain a qualitative assessment of the sensor behavior. This item is closed.

6.2 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, whether generic implications were involved, and whether the event warranted onsite follow up. The following LERs were reviewed:

Unit 1

94-017-00 Feedwater Transient Resulting in Power Excursion

This LER reported a feedwater transient that occurred after the control room operators put a 125V battery charger in the equalize mode following a trouble alarm. The events, licensee's corrective action and inspector's evaluation is discussed in Section 2.3. Although the shift average reactor power did not exceed 100%, the licensee reported this event following the guidance in NRC memorandum (SSINS # 0200) from E.L. Jordan dated August 22, 1980 and license conditions because power level exceeded 102% for 21 seconds. The report followed the overall content requirement of 10 CFR 50.73.

7. MANAGEMENT AND EXIT MEETINGS (30702)

7.1 Resident Exit and Periodic Meetings

The inspector discussed the findings of this inspection with PP&L station management throughout the inspection period to discuss licensee activities and areas of concern to the inspectors. At the conclusion of the reporting period, the resident inspector staff conducted an exit meeting summarizing the preliminary findings of this inspection. 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.

7.2 Other NRC Activities

Members of NRC and NEI visited Susquehanna on November 29, 1994 to discuss the status of Thermo-Lag fire barrier resolution. The members walked down some applications of Thermo-Lag at the plant and discussed the NEI Application Guide with the licensee.