U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-387/84-34; 50-388/84-41

Docket Nos. 50-387 (CAT C); 50-388 (CAT B2)

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: September 15 - November 6, 1984

Inspectors: Jack Strosnider 11/28/84
for R. H. Jacobs, Senior Resident Inspector — date

Jack Strosnider 11/28/84
for L. R. Plisco, Resident Inspector — date

Approved by: Jack Strosnider 11/28/84
Jack Strosnider, Chief Reactor Projects Section 1C, DPRP — date

Inspection Summary:

Areas Inspected:

Routine resident inspection (U-1 hours, U-2 hours of plant operations, maintenance and surveillance, licensee events, open items, startup testing, post trip review process, review of scram timing data, and security.

Results:

Post trip review process is effectively implemented (Detail 8.0); Full MSIV closure test was well planned and successfully performed (Detail 6.2); SPDS installation satisfies license condition (Detail 8.0). One violation was identified involving security (Detail 10.0).

DETAILS

1.0 Followup on Previous Inspection Items

1.1 (Closed) Construction Deficiency Report (388/83-00-14): Electrical Separation Inside Multiple Division Pull/Junction Boxes

The licensee's final report concerning separation in junction and pull boxes was submitted to NRC Region I on June 28, 1984 (PLA-2230). The final report addressed the status of the remaining modifications and the actions taken to prevent recurrence of the problem. All of the Unit 2 modifications have been completed. Several installations were previously inspected in Inspection Report 50-388/84-16.

The inspector reviewed the actions to prevent recurrence described in the report and found them acceptable.

1.2 (Closed) Unresolved Item (388/83-04-01): FSAR Discrepancies

The licensee submitted Revision No. 35 to the Final Safety Analysis Report (FSAR) on July 25, 1984. The inspector reviewed the revised FSAR and verified that the following corrective actions had been completed:

-- The reliance on the 30 day water seal on the feedwater lines was deleted from Section 6.2.3,

-- Statements concerning the sizing of the ADS accumulators in Section 18.1.60, were corrected,

-- Information concerning performance of the SGTS in Sections 6.2, 6.5, 9.4 and 15.6, was corrected,

-- Section 14 was updated to correctly reflect the Unit 2 Startup and Preoperational Test Program.

The corrective actions noted above also completed the action required for Unit 2 License Condition Attachment 1, Paragraph 4.e.

1.3 (Closed) Violation (387/83-12-01): Field Change Request Not Properly Implemented

In May 1983, the inspector identified that four downcomer vent cover plates were not placed in the fully upright stored position due to interference. As a result of this event, the licensee determined that a Bechtel Field Change Request (FCR) had been approved in June 1982 to modify the cover plates to allow storage in the full upright position, but this change was never implemented. The FCR was never completed because during the system turnover process Bechtel no longer had jurisdiction to complete the work specified by the FCR.

The FCR was subsequently implemented and an audit was conducted by Bechtel and PP&L QA of the FCR implementation process. No significant deficiencies were found in the audit. The inspector reviewed Nonconformance Report (NCR) 83-474, which documented the audit results, and records of training of Bechtel personnel on this occurrence. The Bechtel FCR process is no longer in effect at Susquehanna since PP&L now controls all modification work.

1.4 (Closed) Violation (387/83-12-02): Secondary Containment Integrity Violated due to Uncontrolled Door Maintenance

In May 1983, the inspector discovered that secondary containment integrity was not being maintained while maintenance was performed on the outer access door to the Unit 1 reactor building. Shift supervision had authorized the maintenance but was not aware that secondary containment integrity was being violated because insufficient work detail had been provided on the Equipment Release Form which authorized the work.

The licensee's corrective action involved training of work group planners and supervisors and operations supervisors. In addition, this incident is discussed in General Employee Training (GET) and Retraining. By review of attendance sheets, the inspector verified that the Unit of Instruction for GET and GET Retraining contained a review of the incident.

1.5 (Closed) Violation (387/83-25-01): Exceeding 140 Degrees When in Operational Condition 5 (Refueling)

By letter dated February 13, 1984, in response to this violation, the licensee committed to establish an administrative limit of 135 degrees F on reactor coolant system temperature while in the Refueling Mode and to record the temperature hourly. The inspector reviewed Shift Surveillance Log, SO-100-006, Revision 3, which contains the above requirements. During periodic tours of the control room with the plant shutdown, the inspector verified that the hourly temperature readings are being properly monitored and recorded.

1.6 (Closed) Deviation (387/83-29-01; 388/83-32-01): Qualification of Accumulators on Automatic Depressurization (ADS) Valves

FSAR Section 18.1.60 was revised on July 25, 1984 (Revision 35) to correctly reflect that five actuations of the ADS valves at atmospheric pressure in the drywell are equivalent to the design basis of two actuations at 70% of drywell design pressure. The remainder of the licensee's actions were previously reviewed in Inspection Report 388/84-08.

1.7 (Open) Unresolved Item (387/83-29-03; 388/83-32-02): Modifications to the Ultimate Heat Sink

As previously identified in NRC Combined Inspection Report 387/83-29 and 388/83-32, the inspector and Region I management expressed concern that the potential for a freezing condition exists in the spray pond network during extreme weather conditions and that this condition would not be immediately identifiable to the control room operators.

Facility Operating License NPF-22, Attachment 1, Section 4.e, required the licensee to submit an acceptable long-term solution for the spray pond spray network freezing to NRC Region I by September 1, 1984.

In the submittal dated August 31, 1984 (PLA-2232), the licensee committed to complete two modifications prior to the end of 1984. First, the existing spray array draindown pumps will be replaced with self-priming pumps to allow water that has leaked into the spray piping to be pumped out without the need to fill the piping above the centerline. Secondly, level detection devices will be installed in each of the four spray arrays. In addition, to these modifications, an auto-start capability will be added to the draindown pumps by the end of 1985.

The proposed changes and additions to the spray pond systems were reviewed by the resident inspectors and NRC Region I and found to be acceptable. The licensee's response closes license condition 4.e, Attachment 1. The unresolved item will remain open pending completion of the proposed modifications.

2.0 Review of Plant Operations

2.1 Operational Safety Verification

The inspector toured the control room area daily to verify proper manning, access control, adherence to approved procedures, and compliance with LCOs. Instrumentation and recorder traces were observed and the status of control room annunciators were reviewed. Nuclear instrument panels and other reactor protective systems were examined. Effluent monitors were reviewed for indications of releases. Panel indications for onsite/offsite emergency power sources were examined for automatic operability. During entry to and egress from the protected area, the inspector observed access control, security boundary integrity, search activities, escort ability of radiation monitoring equipment.

The inspector reviewed shift supervisor, plant control operator, and nuclear plant operator logs covering the entire inspection period. Sampling reviews were made of tagging requests, night orders, the bypass log, incident reports, and QA nonconformance reports. The inspector also observed several shift turnovers during the period.

No unacceptable conditions were identified.

2.2 Station Tours

The inspector toured accessible areas of the plant including the control room, relay rooms, switchgear rooms, penetration areas, reactor and turbine buildings, radwaste building, ESSW pumphouse, Circulating Water Pumphouse, Security Control Center, diesel generator building, plant perimeter and containment. During these tours, observations were made relative to equipment condition, fire hazards, fire protection, adherence to procedures, radiological controls and conditions, housekeeping, security, tagging of equipment, ongoing maintenance and surveillance and availability of redundant equipment.

No unacceptable conditions were identified.

3.0 Summary of Operating Events

3.1 Unit 1

On October 6, 1984 while performing quarterly individual rod scram testing of 10 percent of the rods, two rods did not scram on the initial attempt. The testing was expanded to include all 185 rods, and two additional rods did not scram and nine rods hesitated prior to inserting. (See Special Inspection Report 50-387/84-35; 50/388/84-44).

On October 12, the unit commenced a power reduction based on information from GE concerning the mechanism of the scram pilot solenoid valve (SPSV) failures identified on October 6. The unit was manually scrammed from 23 percent power at 4:00 a.m. on October 13.

The unit returned to power on October 17 after replacement of polyurethane SPSV disc holder subassemblies, but was manually scrammed at 9:21 p.m. October 18 in order to perform an overdue surveillance on the Scram Discharge Vent and Drain Valves. The valves did not pass the surveillance. (See Special Inspection Report 50-387/84-35; 50-388/84-44).

The scram discharge vent and drain pilot solenoid was replaced with a new valve having a greater air bleed off rate. The unit was started up on October 21, then manually scrammed from 7 percent power to retest the valves. The test was completed satisfactorily, and the unit restarted and reached criticality at 3:52 a.m. on October 22, 1984.

Scheduled power reductions were conducted throughout the period to optimize fuel usage until the refueling outage, and to perform rod pattern exchanges.

3.2 Unit 2

On September 20, the unit was scrammed from 75 percent power during a scheduled Startup Test ST 27.1, Turbine Trip. The unit returned to criticality at 9:21 p.m. September 21.

At 5:01 p.m., September 28, the unit reached 100 percent power for the first time.

At 1:20 a.m., September 30, the unit scrammed on a main turbine trip caused by a B Moisture Separator Drain Tank High Level (MSDT) High Level during performance of reactor feed pump startup tests. The high level was caused by the improper operation of the MSDT level controller. The unit returned to criticality at 8:45 p.m. October 1, 1984.

On October 12, the unit commenced a power reduction due to information received from GE concerning the failure mechanism of the scram pilot solenoid valves (See Section 3.1) and the unit was manually scrammed from 15 percent power at 5:12 a.m. on October 13.

The unit returned to operation on October 17 after completion of the SPSV parts replacements.

At 1:50 a.m. October 27, the unit was scrammed from 100 percent power as part of Startup Test ST 25.3, "MSIV Closure Test". The precommercial outage, scheduled to last 69 days, then commenced. (See Section 6.2).

4.0 Licensee Reports

4.1 In Office Review of Licensee Event Reports

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

Unit 1

84-036/00, Grease in RPS M-G Set Motor Windings Caused Short Circuit and ESF Actuations

84-038/00, RHR Relay Not Included in Surveillance Procedure

84-039/00, Turbine Building SPING Out of Service

**84-040/00, Diesel Generator Failures

84-041/00, Missed Chemistry Samples

Unit-2

84-016/00, RHR Pump Discharge Pressure Instrument Surveillance Test Completed Late

*84-017/00, Two Scrams Due to Water in Main Turbine Crossaround Pipe

*84-018/00, Reactor Scram Due to False Power Load Unbalance Signal

84-019/00, HPCI and One RHR Pump Inoperable Simultaneously

84-020/00, RWCU Isolation During Instrument Calibration

*Previously discussed in Inspection Report 50-387/84-26; 50-388/84-33

**Further discussed in Detail 4.2.

4.2 Onsite Followup of Licensee Event Reports

4.2.1 LER 84-041, Diesel Generator Failures

This LER discussed diesel generator (DG) test failures due to a failed turbocharger on the 'D' D/G and slow start times on the 'B' D/G. These occurrences were discussed in Inspection Report 50-387/84-26; 50-388/84-33 and are updated as follows. Three of the slow start time occurrences on the 'B' D/G have been classified as valid failures in accordance with Regulatory Guide 1.108. This brings the total number of valid failures in the last 100 starts to five, which requires a testing frequency of one start every three days. The problem with the slow start time on the 'B' D/G was resolved by replacing the fuel oil booster pump and check valve and tightening some loose flanges on the fuel oil piping between the day tank and the booster pump. The loose flanges allowed air to enter the fuel oil system which apparently was the primary cause of the slow start times.

On September 24, the 'B' D/G tripped during the start sequence. The problem was traced to the safety fuel control trip valve. Misoperation of this valve prevents bleeding off the fuel control cylinder which delayed operation of the diesel fuel racks, causing a trip. Some metal shavings and some corrosion were found when the fuel control trip valve was disassembled. The valve was cleaned and reassembled. During an emergency diesel start, two solenoid operated control trip valves operate to vent the fuel control cylinder. Thus, the failure of the safety trip control valve would not affect diesel operation in the "emergency" mode and hence this failure was classified as "non-valid". The degradation of the trip control valve was probably caused by poor quality air in the control system. Problems with moisture in the control air system have been previously noted. Air dryers are scheduled to be installed in this sytem during the first refueling outage.

4.3 Review of Periodic and Special Reports

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

The following periodic and special reports were reviewed:

-- Monthly Operating Report - August 1984

-- Monthly Operating Report - September 1984

-- Special Report - Unit 2 Loose Parts Channel Not Operable

-- Special Report - ECCS Injections (Unit 1)

-- Special Report - RCIC Injection (Unit 2) dated October 3, 1984

-- Special Report - Diesel Generator 'A' Non Valid Failure dated October 26, 1984

The above reports were found acceptable.

5.0 Monthly Surveillance and Maintenance Observation

5.1 Surveillance Activities

The inspector observed the performance of surveillance tests to determine that: the surveillance test procedure conformed to technical specification requirements; administrative approvals and tag-outs were obtained before initiating the test; testing was accomplished by qualified personnel in accordance with an approved surveillance procedure; test instrumentation was calibrated; limiting conditions for operations were met; test data was accurate and complete; removal and restoration of the affected components was properly accomplished; test results met Technical Specification and procedural requirements; deficiencies noted were reviewed and appropriately resolved; and the surveillance was completed at the required frequency.

These observations included:

-- SO-024-001D, Monthly Diesel Generator Operability Test, performed on October 3, 1984.

-- SO-255-003, Eighteen Month Scram Discharge Volume Vent and Drain Valve Operability Test, performed on October 27, 1984.

No unacceptable conditions were identified.

5.2 Maintenance Activities

5.2.1 Unit 2 'A' Recirculation Pump Motor Generator (MG) scoop tube positioner arm relocation

On September 21, 1984 the inspector observed portions of the relocation of the 'A' recirculation pump MG scoop tube positioner arm to the lower hole on the pivot arm. The 'A' recirculation pump had been experiencing minor flow oscillations throughout its flow range during startup testing. The scoop tube positioner arm on the 'A' MG set was attached to the upper hole of the positioner pivot arm. The other three MG set positioner pivot arms were attached to the lower hole in the pivot arm which provides the positioner with a small increase in mechanical advantage. It was thought that the flow oscillations were due to forces in the fluid coupler trying to move the scoop tube while the positioner tries to hold the positioner arm and thus, the scoop tube in position. The inspector reviewed WA-V47783, the associated work plan and Equipment Release Form A17785. No unacceptable conditions were noted. Retest following the positioner arm relocation showed that the flow oscillations had decreased.

5.2.2 Unit 2 HPCI

On October 4, 1984, the licensee determined by sampling that there was water in the Unit 2 HPCI oil system. There had been several previous occurrences of water in the HPCI oil system which were believed to be due to contaminated oil and condensation in the sump. The oil, which is GULF CREST 32 VT, had been changed out in July and September but the moisture problem had returned. On a monthly basis (or at plant staff request), HPCI oil is sampled and the results sent to PP&L Hazelton labs for analysis. The inspector reviewed several lab results performed on oil samples taken between June and September 1984, which indicated levels of moisture content up to 1 percent or 10,000 ppm. The nominal specification used by PP&L Hazelton for moisture content in oil is 100 ppm although oil retains its lubrication properties at moisture levels much higher than 100 ppm. Also since samples are taken from the sump at no specified sump location or oil temperature, the samples are not necessarily representative of moisture content of oil seen at the bearing or in the HPCI control oil system. During discussions with the licensee, it was apparent that no fixed limit existed for moisture content which, if the limit was exceeded, required HPCI to be declared inoperable.

In response to the inspector's concerns, the licensee began taking oil samples from various sump locations in the sump every time HPCI was run and initiated action to establish a moisture content limit.

On October 10, 1984, HPCI was removed from service due to vibration problems and to determine the source of water inleakage. The inspectors observed HPCI maintenance on October 11 and 12 and reviewed Work Authorizations (WA) V44183, V43945, V44218 and S44828. During a freon check, a minor leak was found in the lube oil cooler (heat exchanger). However, it was determined that the heat exchanger had no margin to allow tube plugging and no other heat exchanger was readily available. The heat exchanger was manufactured by Whitlock Co. and contained Admirality brass tubes. The lube oil was changed out and water removed from low points in the HPCI oil system. The day before HPCI was removed from service, an operator found the lube oil isolation valve to the coupling end turbine bearing shut which prevents lube oil flow to that bearing. That bearing and the main pump coupling end bearing (the source of the high vibration) were inspected with no problems found. The vibration problem was resolved by realignment.

HPCI was returned to service on October 18. Oil samples on HPCI runs since its return to service have indicated low moisture content, on the order of 0.03 percent. The licensee has established a limit of 0.5 percent moisture in HPCI oil based on discussions with Terry Turbine, Gulf Oil Co. and PP&L Nuclear Plant Engineering. The licensee has initiated changes to the HPCI system operating procedures to require declaring HPCI inoperable when this limit is exceeded. Modification requests have been prepared to establish an oil sample point on the discharge of the auxiliary oil pump to enable obtaining a representative sample. A modification request has also been prepared to obtain a new heat exchanger. In the interim, sampling of HPCI oil will continue whenever HPCI is run.

With respect to the mispositioned oil valve discussed above, the licensee immediately yellow tagged all valves in the HPCI oil system on both units and operators are checking their position on a shiftly basis. A functional test of the oil system (which provides a better verification of the proper throttle position of the oil system valves) is being incorporated into the operating procedure. Modification requests have been initiated to install orifices in the lube oil lines to the bearing and provide stem lock devices on other valves, as a permanent repair. The inspector will followup on licensee's actions in a subsequent inspection. (387/84-34-01; 388/84-41-01)

6.0 Startup Test Program (Unit 2)

The inspector witnessed portions of selected tests to verify that:

-- Procedures with appropriate revision were available and used;

-- Test changes were identified and implemented without changing the basic objectives of the test, in accordance with station procedures and Technical Specifications;

-- Prerequisities were completed and verified;

-- Initial conditions were met;

-- Special test equipment required by the procedures was utilized and calibrated;

-- Test was performed in accordance with the procedure;

-- Results were satisfactory and met the acceptance criteria;

-- Test exceptions or deviations were identified, documented and reviewed.

6.1 ST 25.1 - Main Steam Isolation Valve (MSIV) Testing

On October 5, 1984, the inspector witnessed ST 25.1, MSIV Testing. This test is performed to determine MSIV closure time at the maximum power level that will not cause a scram. Each MSIV is shut one at a time and is reopened after conditions are stabilized. The test was conducted at 90% power. As the valves were shut, the inspector observed the following minimal parameter changes power increase of about 10%; pressure increase from about 976 psi to 1009 psi and vessel level drop from 35 inches to 32 inches. No problems were encountered with the test.

6.2 ST 25.3 - Full MSIV Isolation

On October 27, 1984 the inspector witnessed Startup Test ST 25.3, Full MSIV Isolation from 100 Percent Power. This test was performed to demonstrate the reactor transient behavior that results from the simultaneous full closure of all MSIV's at 100 percent power. The full isolation was initiated by pulling fuses which simulated a low steam line pressure signal. The resulting reactor scram and transient response was monitored on GETARS. Based on analysis of the data, the Acceptance Criteria concerning MSIV closure time and response of reactor pressure, level, neutron flux and heat flux were verified.

Prior to the test the inspectors reviewed the test procedure and the pre-test results of a simulation of the startup test performed on the RETRAN-02 model. Additionally, the Unit 1 test results were reviewed for comparison.

The startup test was initiated at 1:50 a.m., October 27, with the unit at 100 percent rated power. The MSIV's closed on the simulated low steam line pressure signal, resulting in a reactor scram, main turbine trip, and recirculation pump trip. During the transient, reactor level initially decreased to approximately -40 inches, which initiated HPCI and RCIC automatically. HPCI and RCIC subsequently tripped at +54 inches on the level recovery.

The maximum reactor level reached was 76 inches. The maximum pressure reached during the first 30 seconds of the transient was 1032 psig. One safety relief valve ("E" SRV) lifted at a pressure of 1075 psig several minutes after the scram during the pressure increase due to decay heat. The SRV was then operated manually to maintain reactor pressure during the unit recovery. Suppression pool temperature reached a maximum of 100 degrees F. After level and pressure were stabilized, HPCI was placed in full flow test and RCIC was used to maintain vessel level. All systems responded as designed during the transient. The operator response to the expected transient and subsequent recovery actions were performed in a professional manner, and the demanding test went smoothly due to thorough preparation.

The inspector reviewed the completed test documentation and the computer generated data. Based on the data review, the MSIV's closed as required in 3 to 5 seconds, and the pressure and heat flux valves did not exceed predicted values. All Acceptance Criteria were satisfied.

7.0 Generic Letter 83-28, Salem ATWS Event Follow-up

7.1 Background

Generic Letter 83-28 required certain actions of all licensees as a result of the Salem ATWS Events in February, 1983. Actions were required in four areas: (1) post-trip review, (2) equipment classification and vendor interface, (3) post maintenance testing and (4) reactor trip system reliability improvements. PP&L submitted responses to Generic Letter 83-28 in letters dated November 4, 1983 and March 1, 1984. The purpose of this inspection was to review licensee's near term actions in the post trip review area. The licensee's actions in the equipment classification, vendor interface and post maintenance testing areas were reviewed in Inspection Report 50-387/84-29; 50-388/84-35 dated September 12, 1984. The area of reactor trip system reliability involves longer term actions only and will be reviewed as necessary following issuance of a safety evaulation report by the Office of Nuclear Reactor Regulation (NRR).

7.2 Program Review

The licensee's program for post trip review was reviewed to determine:

-- that procedures and equipment exist to adequately conduct a post-trip review,

-- that safety assessments of reactor trips are performed,

-- that responsibilities and authorities of plant personnel who perform the review and analysis are delineated,

-- that necessary qualifications and training for the responsible personnel have been established,

-- that criteria has been established for determining the acceptability of restart,

-- that criteria is established for review by the Plant Operations Review Committee (PORC).

7.3 Implementation

The licensee conducts a post trip review of all reactor scrams in accordance with Administrative Directive AD-QA-415 "Post Transient/Reactor Scram Evaluation", Revision 0, dated October 27, 1983. Following a scram, a shift debriefing is held and all abnormal conditions are recorded on a scram open items list. The STA reviews the scram data (computer printouts, strip charts, and GE Transient Analysis Recording (GETARS) printouts) to determine plant performance. A Supervisor, Scram Investigations, is assigned to coordinate investigations and resolve scram open items. A PORC meeting is held prior to plant startup after all scrams to ensure that the cause of the scram has been correctly identified and that equipment and systems functioned as correctly identified and that equipment and systems functioned as designed during the transient. The Duty Manager, a senior station manager who acts for the superintendent during off hours, authorizes unit startup following satisfactory resolution of the scram open items. Subsequently, the STA produces a scram summary report which summarizes the cause and the events leading up to the scram and contains all scram related data. This report is provided to Senior PP&L management and permits followup review of the event.

Installed equipment at Susquehanna provides an extensive capability to conduct event review. Each unit has computer systems which produce two post trip review logs and a sequence of event (SOE) log. The SOE log monitors 64 parameters and has the capability to establish the order of occurrence of events with a resolution of four milliseconds. The two post trip logs monitor a total of 62 NSSS and balance of plant (BOP) parameters and provide analog data. The NSSS log provides data at five second intervals for five minute periods before and after the trip and the BOP log provides data for 30 minutes before and after a trip. A time history report monitoring hundreds of parameters, both digital and analog, is also available.

The inspector reviewed AD-QA-415, Scram Summary Reports for Unit 1 scrams on February 25 and July 3, 1984, and Unit 2 scrams on July 15 and August 7, 1984, and PP&L letters to D. Eisenhut, NRC dated November 4, 1983 and March 1, 1984. The inspector also discussed post trip reviews with several STAs and other plant staff. In addition, during routine inspection activities, the inspector reviews scram related data and periodically attends shift debriefings and scram open item meetings.

7.4 Findings

The licensee's post trip review process meets the intent of Generic Letter 83-28 and is effectively implemented. For each scram reviewed, the cause of the scram was correctly identified and equipment performance properly evaluated prior to reactor startup.

The inspector noted that AD-QA-415 specifies determining the response times and performance of various safety systems, although no response times are required to be determined for the reactor protection system (RPS) or end-of-cycle (EOS) and ATWS recirculation pump trips. Although

the information is available on the SOE, the STAs do not routinely check time differences between actuation signals (such as turbine control valve fast closure) and signals that confirm that the scram pilot solenoid valves are deenergized or that recirculation pump breaker trip coils are energized. The inspector discussed this concern with the licensee who agreed to evaluate this and modify AD-QA-415 as necessary. This item will be reviewed in a subsequent inspection. (387/84-34-02)

8.0 TMI Action Plan Requirements

I.D.2 - Plant Safety Parameter Display Console

NUREG 0737 and Supplement I (Generic Letter 82-33) required each licensee to install a safety parameter display system (SPDS) that would display to operating personnel a minimum set of parameters which define the safety status of the plant.

Facility Operating License NPF-14 (Unit 1), Item 2.C.28(g), required the licensee to complete the SPDS on September 30, 1983. By other correspondence, this date was extended to July 1, 1984. Facility Operating License NPF-22 (Unit 2), Attachment 2, Item (a) required the licensee to have the SPDS fully operational and operators trained no later than July 1, 1984. Licensee letter PLA-2241, dated July 20, 1984, stated that the SPDS for Units 1 and 2 were placed in an operational status on June 30, 1984 and that their action satisfied the operating license requirements.

The inspector reviewed the associated documentation and correspondence, and witnessed the systems operation to verify that the system operated as discussed in the licensee's response to Generic Letter 82-33, FSAR Section 18.1.17, and the SPDS Safety Evaluation Report dated September 30, 1983, and that the license conditions were satisfied.

The inspector noted that the following requirements were met concerning the system operation:

-- displays are located convenient to the control room operators and in the Technical Support Center and Emergency Operations Facility

-- primary display provides continuous indication of the minimum parameter set necessary to readily and reliably assess plant status

-- display is designed to incorporate accepted human factors principles

-- system utilizes algorithms to validate the displayed data and displays diagnostic messages for unreasonable data

-- system indicates parameter magnitudes, trends and alarm conditions

The inspector reviewed Unit of Instruction SY017M-5, Revision 0, Safety Parameter Display System, and the Roster of Requal Trainees for this training for the period of November 1983 to February 1984. A three hour training session including hands on training was conducted for the control room operators and STA's under the requal training program during the period.

The inspector has noted several events and tests on both Units during which the STA effectively utilized the SPDS to monitor and trend plant parameters. The system proved to be very useful in rapid assessment and evaluation of plant status.

9.0 Scram Insertion Time Data Review

As stated in Special Inspection Report 50-387/84-35; 50-388/84-44, the licensee conducted individual rod scram testing on both Units 1 and 2 between October 18 - 24, 1984, from power levels of 50 - 60 percent. The testing was conducted in accordance with surveillance procedures SR-155-002 and SR-255-002, "Scram Time Measurement of Rods Following Maintenance or Modification". The inspectors witnessed portions of the testing.

The post-maintenance rod testing was performed due to the replacement of the disc holder sub-assemblies in the Unit 1 and 2 scram pilot solenoid valves, and the action discussed in NRC Region I Confirmatory Action Letter (CAL) 84-18 dated October 17, 1984. As stated in the CAL, the scram insertion times of all the control rods in both Units 1 and 2 were to be demonstrated acceptable as required by Technical Specification Surveillance Requirement 4.1.3.2.b.

The Unit 1 testing commenced on October 18, 1984, and the data review was completed October 30. The procedure was properly authorized and reviewed, and the prescribed test prerequisites were met. During the Unit 1 rod testing, the unit was scrammed on October 18, due to a missed surveillance on the scram discharge volume vent and drain valves. The GETAR's data for the fully withdrawn rods was used to meet the surveillance requirement. Prior to the scram, 48 rods were individually tested, and eight other rods were individually tested following the units return to power on October 22. All 185 rods were tested with the following results:

Notch Position	T.S. Average Limit	Average As Found	Average of Slowest 2 x 2 Array
45	0.43	0.278	0.288
39	0.86	0.576	0.605
25	1.93	1.298	1.368
05	3.49	2.396	2.522

The slowest rod reached notch position 05 in 2.669 seconds from the time the scram pilot solenoid was deenergized. All of the Technical Specification requirements were met, and no evidence of hesitation was noted during the tests or in the data review.

The inspector compared the data obtained from the strip charts plugged into the control room test panel and the GETAR's data for the same rods and found the two methods obtained similar results. In the cases where the data differed, the licensee utilized the more conservative numbers.

The inspector noted several administrative deficiencies in the test documentation and in the surveillance procedure, which he brought to the attention of the appropriate station staff. The deficiencies were corrected promptly, and the surveillance procedure was revised.

The Unit 2 testing commenced on October 20 and the data review was completed November 1. All 185 rods were tested utilizing the individual rod scram method at the Control Rod Test Instrument Panel (2C610), with the following results:

Notch Position	T.S. Average Limit	Average As Found	Average Slowest of 2 x 2 Array
45	0.43	0.259	0.280
39	0.86	0.566	0.620
25	1.93	1.295	1.390
05	3.49	2.348	2.470

The slowest rod reached notch position 05 in 2.71 seconds. All of the Technical Specification requirements were satisfied, and no evidence of hesitation was noted during the testing.

10.0 Exit Interview

On November 9, 1984, the inspector discussed the findings of this inspection with station management.

11.0 Security Incident - Allegation

THIS PARAGRAPH CONTAINS SAFEGUARDS INFORMATION WHICH IS EXEMPT FROM PUBLIC DISCLOSURE; IT IS INTENTIONALLY LEFT BLANK.

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