U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-277/85-40

Docket No. 50-277

License No. DPR-44

Licensee: Philadelphia Electric Company
2301 Market Street
Philadelphia, Pennsylvania 19101

Facility Name: Peach Bottom Atomic Power Station Unit 2

Inspection At: Delta, Pennsylvania

Inspection Conducted: October 26 - December 31, 1985

Inspectors: T. P. Johnson, Sr. Resident Inspector
J. H. Williams, Resident Inspector
H. I. Gregg, Lead Reactor Engineer
S. V. Pullani, Fire Protection Engineer
J. E. Beall, Project Engineer

Reviewed by: J E Beall — 1/31/86
J. E. Beall, Project Engineer — date

Approved by: Robert M. Gallo — 1/31/86
Robert M. Gallo, Chief — date
Reactor Projects Section 2A, DRP

Inspection Summary: Routine, on-site regular and backshift resident inspection (223 hours) of accessible portions of Unit 2, operational safety, RHR pumps, snubbers, radiation protection, physical security, control room activities, licensee events, surveillance testing, maintenance, outage activities and outstanding items. Review of feedwater hammer transient and scram on December 26, 1985.

Results: The cause of Radwaste Building cable tray fire remains undetermined. The licensee identified a failure to follow Technical Specification LCO action statement regarding inoperable containment isolation valves (Detail 6.2.2). A control rod was blocked out of service at position 48 with the unit at power; the ability to meet Technical Specification shutdown margin requirements for this condition is unresolved (Detail 4.1.9).

DETAILS

1. Persons Contacted

J. F. Mitman, Maintenance Engineer
*R. S. Fleischmann, Manager Peach Bottom Atomic Power Station
A. A. Fulvio, Technical Engineer
A. E. Hilsmeier, Senior Health Physicist
D. L. Oltmans, Senior Chemist
F. W. Polaski, Outage Planning Engineer
S. R. Roberts, Operations Engineer
*D. C. Smith, Superintendent Operations
S. A. Spitko, Administration Engineer
*J. E. Winzenried, Superintendent Plant Services

Other licensee employees were also contacted.

*Present at exit interview on site and for summation of preliminary findings.

2. Unit 2

The unit began the inspection period at 100% power. On November 10, 1985, a cable tray fire occurred in the Radwaste Building (see detail 4.2.1). On November 29, 1985, during a scheduled plant shutdown for maintenance, the unit scrammed from 33% power during turbine stop valve testing (see detail 4.2.2). The unit remained in cold shutdown until December 24, 1985. Licensee work activities during this shutdown included RHR pump inspections, mechanical snubber changeout, environmental equipment qualification modifications and preventive maintenance, and testing.

On December 24, 1985, the unit restarted and on December 26, 1985, the unit scrammed from 44% power during feedwater pump and level control system troubleshooting. During this troubleshooting a feedwater hammer transient caused a feedwater leak on the feedwater pump suction piping (see detail 4.2.3). The unit restarted on December 29, 1985.

3. Previous Inspection Item Update

3.1 (Closed) Violation (277/82-25-01). Failure to maintain the seismic qualifications of the ADS Back-Up Nitrogen Supply and to perform valid checks of nitrogen supply as required by procedure. The inspector verified that the corrective actions specified in the licensee's letter of February 25, 1983, had been taken. The surveillance test which was previously revised because of a violation to include visual inspection of the seismic bottle restraints was revised to more clearly require that all bottles be placed in the installed racks and restraints be secured. In addition, an individual "restraint secured" check-off was required for each bottle. The inspector had no further questions. This item is closed.

3.2 (Closed) Unresolved Item (277/82-06-03). Emergency diesel generator (DG) fuel oil Technical Specification (TS) requirements. On March 28, 1982, the licensee's DG fuel supply was less than the 104,000 gallon TS minimum. The licensee reported the low fuel supply with an LER (#2-82-08), which was reviewed in NRC Inspection 277/82-06. The inspector at that time expressed a concern regarding the adequacy of DG fuel oil Technical Specification; specifically the fuel oil storage and transfer system operability and the monthly check of fuel oil quantity. The inspector reviewed Technical Specification 3.9.A.2 and Technical Specification 4.9.A.1, and ST 8.1, DG Full Load Test. TS 4.9.A.1.C requires a monthly check of diesel fuel quantity, however the licensee performs the check daily per ST 9.1-2Z, the Surveillance Log. Technical Specification 4.9.A.1.a requires a monthly operability check of the diesel fuel oil transfer system and ST 8.1 performs this check weekly on the diesel fuel oil transfer pumps and day tanks. Based on the above, this item is closed.

3.3 (Closed) Inspector Follow Item (277/81-24-04). Review of off-gas system design. The licensee performed modification #84-116 to replace the Unit 2 compressed storage off-gas system with an ambient charcoal absorber system. This modification was reviewed in NRC Inspection 277/85-08. This item is closed.

3.4 (Closed) Unresolved Item (277/81-24-05). Root valves not included on system prints. The licensee is currently implementing a Critical Equipment Monitoring System (CEMS). CEMS is a data acquisition and status system for plant equipment including all plant valves (remotely operated, manual, root, and instrument). CEMS implementation includes detailed system walkdown, equipment identification and rigging, and P&ID updating to include missing valves. The licensee intends to continue with CEMS implementation until completion. Based on the above, the unresolved item for root valves is closed. The inspector will follow CEMS implementation.

3.5 (Closed) Violation (277/85-12-01). Failure to maintain the seismic qualification of nitrogen bottle OB55385. This violation was caused by errors in judgment of operations personnel performing ST 7.9.2, "Daily Check of Seismic Gas Supply Bottle Pressures". The licensee instructed operations personnel on the requirements for seismic qualification of the nitrogen bottles and posted signs near the gas bottle racks to describe the seismic restraint requirements. The inspector examined a sampling of the signs in the Unit 2 Reactor Building and the Rad Waste Building. The inspector had no further questions. This item is closed.

3.6 (Closed) Violation (277/82-25-03). Failure to write a Maintenance Request Form (MRF) for malfunctioning main steam line drain valves. The licensee responded to the violation in a letter dated February 25, 1983. The inspector reviewed the licensee's response and found

it to be adequate. The licensee had failed to investigate and document on a MRF the equipment malfunction. The individuals involved were counseled. The inspector will continue to routinely check equipment status and MRFs for equipment malfunctions during daily tours. Based on the above, this item is closed.

3.7 (Closed) Inspector Follow Item (277/83-12-04). Control rod position indication probe (PIP) functional test. When a control rod PIP was replaced, a complete functional test was not performed. The inspector reviewed maintenance procedure M-3.1, Control Rod Drive Replacement, Revision 18, March 21, 1985 and ST-10.8, Control Rod Withdrawal Tests, Revision 10, December 12, 1984. M-3.1 requires post maintenance testing including the performance of ST-10.8. ST-10.8 requires a check of rod position information system (RPIS) during control rod exercising including the RPIS full in (green light), full out (red light) and notch positions. Based on the above, this item is closed.

3.8 (Closed) Unresolved Item (277/84-15-03). The licensee had previously noted that during lifting of the reactor vessel head, the Unit 2 reactor head strongback could contact the reactor building crane support beams prior to actuation of the overtravel limit switch. ANSI B 30.2 requires the actuating mechanism on the limit device to be located so that it will trip the device under all conditions in sufficient time to prevent contact of the hook or load block with any part of the trolley or crane. The matter was unresolved pending licensee actions to correct the deficiency. Under Modification 1494 the licensee replaced the one setpoint geared limit switch with a dual setpoint geared limit switch. This modification was performed on both Units 2 and 3. The inspector reviewed the modification documentation including: the minutes of the PORC review; the Safety Evaluation dated January 2, 1985; Maintenance Request Forms (MRF) numbered 2-17-M8502009, 2-17-M8502010, 3-17-M 8502011, and 3-17-M8502012; and, the modification acceptance test, MAT 85-009, dated May 9, 1985. The inspector also discussed the modification with the Modification Engineer and maintenance engineering personnel. The licensee's tests demonstrated that the load or hook could not make contact with the trolley or crane. This item is closed.

3.9 (Closed) Inspector Follow Item (277/81-09-01). ECCS room drain communication. To prevent room-to-room leakage, the licensee has plugged ECCS room drains. COL GP-2A, Reactor Startup Order, Revision 62, July 1, 1985, step 6 has a sign-off for verifying ECCS room drains are plugged. This item is closed.

3.10 (Closed) Inspector Follow Item (277/85-21-01). Emergency diesel generator (DG) interpolar connector bars on Colt Industries supplied generators. In May, 1985, a 10 CFR 21 report was made regarding Colt Industries generators at Calvert Cliffs. Peach Bottom utilizes a similarly designed generator. The generator has an interconnecting bar between adjacent poles on the rotor which could potentially break

off causing damage to the generator stator. The failure mechanism was evaluated as fatigue cracking. The licensee removed the interpolar connector bars on all four DGs per SP-813, DG Interpolar Connector Removal, Revision 0, June 14, 1985. The inspector observed the interpolar bars removed on the E-2 DG on June 17, 1985 (reference NRC Inspection 50-277/85-25) and on the E-1 DG on July 30, 1985 (reference NRC Inspection 50-277/85-30). The interpolar bars were removed on the E-3 DG on September 23, 1985 and on the E-4 DG on September 4, 1985. The inspector reviewed the applicable MRFs for the E-3 DG (MRF 3-52-M8504945) and the E-4 DG (MRF 3-52-M8504946). No unacceptable conditions were noted. Based on the above, this item is closed.

3.11 (Open) Inspector Follow Item (277/85-08-04). The licensee identified a problem with the control rod drive hydraulic control unit (HCU) scram outlet valve isolation valves (13-112) on Unit 2. This valve (13-112) is the manual isolation gate valve on the scram discharge riser pipe. The problem concerns cracking of the valve stem to valve gate (disc) connection in one of 18 valves inspected. The cracking was completely through one wall of the valve disc connection, however the other wall remained intact and no separation of the stem and disc occurred. If separation were to occur, the valve disc (valve is normally open and is required to be open for control rod to scram) could potentially then "float" and jeopardize the capability of the control rod to scram. The Unit 2 valve supplier is Dresser, Inc. (Hancock valves) and the disc material is 420 stainless steel.

The inspector reviewed MRF 2-03-M8501589 which replaced all 185 HCU 13-112 valve discs, stems, and bonnet gaskets with supposedly less susceptible material, Type 410 stanless steel. The HCU 13-112 valve maintenance was completed on March 26, 1985, and the operational verification form was completed on June 21, 1985, prior to Unit 2 startup after the 1984-1985 pipe replacement outage. This item remains open pending further NRC review of the material susceptibility question.

3.12 (Closed) Inspector Follow Item (277/85-08-01). Minor errors in P&ID M-358, Standby Liquid Control (SBLC) system. The licensee submitted a drawing change request to correct the SBLC P&ID. The inspector reviewed P&ID M-358, Revision 15, dated March 25, 1985. The missing "locked closed (LC)" designations and incorrect valve identifications were corrected. This item is closed.

3.13 (Closed) Unresolved Item (277/85-15-02). Certain battery rack cell spacer rods in the 125/250 VDC Class IE batteries were found not installed as required by the battery vendor and a silicone compound not specifically identified by the vendor was used as a lubricant during battery installation. The licensee reverified all battery rack nut-bolt torque settings and the inspector independently verified that none of the nuts was loose. The licensee obtained written confirmation from the battery vendor that the silicone compound used during

battery installation was compatible with cell materials. The inspector reviewed the vendor's response dated May 29, 1985, and had no further questions at this time. This item is closed.

3.14 (Closed) Unresolved Item (277/85-15-04). Uncovered fluid ports of hydraulic snubbers. The inspector reviewed the licensee's recently amended snubber Technical Specification (TS) (amendment 107/111) dated March 19, 1985, and verified that the issue of uncovered fluid ports is now addressed in 4.11.D.3 TS. The licensee's TS 4.11.D.3 contains the standard TS provision for uncovered fluid ports. This item is closed.

4. Plant Operations Review

4.1 Station Tours

The inspector observed plant operations during daily facility tours. The following areas were inspected:

-- Control Room
-- Cable Spreading Room
-- Reactor Building
-- Turbine Building
-- Radwaste Building
-- Pump House
-- Diesel Generator Building
-- Protected and Vital Areas
-- Security Facilities (CAS, SAS, Access Control, Aux SAS)
-- High Radiation and Contamination Control Areas
-- Shift Turnover

4.1.1 Control Room and facility shift staffing was frequently checked for compliance with 10 CFR 50.54 and Technical Specifications. Presence of a senior licensed operator in the control room was verified frequently.

4.1.2 The inspector frequently observed that selected control room instrumentation confirmed that instruments were operable and indicated values were within Technical Specification requirements and normal operating limits. ECCS switch positioning and valve lineups were verified based on control room indicators and plant observations. Observations included flow setpoints, breaker positioning, PCIS status, and radiation monitoring instruments.

4.1.3 Selected control room off-normal alarms (annunciators) were discussed with control room operators and shift supervision to assure they were knowledgeable of alarm status,

plant conditions, and that corrective action, if required, was being taken. In addition, the applicable alarm cards were checked for accuracy. The operators were knowledgeable of alarm status and plant conditions.

4.1.4 The inspector checked for fluid leaks by observing sump status, alarms, and pump-out rates; and discussed reactor coolant system leakage with licensee personnel.

4.1.5 Shift relief and turnover activities were monitored daily, including backshift observations, to ensure compliance with administrative procedures and regulatory guidance. No inadequacies were identified.

4.1.6 The inspector observed main stack and ventilation stack radiation monitors and recorders, and periodically reviewed traces from backshift periods to verify that radioactive gas release rates were within limits and that unplanned releases had not occurred. No inadequacies were identified.

4.1.7 The inspector observed control room indications of fire detection instrumentation and fire suppression systems, monitored use of fire watches and ignition source controls, checked a sampling of fire barriers for integrity, and observed fire-fighting equipment stations. No inadequacies were identified.

4.1.8 The inspector observed overall facility housekeeping conditions, including control of combustibles, loose trash and debris. Cleanup was spot-checked during and after maintenance. Plant housekeeping was generally acceptable.

4.1.9 The inspector verified operability of selected safety related equipment and systems by in-plant checks of valve positioning, control of locked valves, power supply availability, operating procedures, plant drawings, instrumentation and breaker positioning. Selected major components were visually inspected for leakage, proper lubrication, cooling water supply, operating air supply, and general conditions. No significant piping vibration was detected. The inspector reviewed selected blocking permits (tagouts) for conformance to licensee procedures.

During a tour of Unit 2 reactor building at 12:30 p.m. on December 26, 1985, the inspector noted that control rod hydraulic control unit (HCU) #22-11 was blocked out of service. The four directional control valve solenoids were unplugged and tagged, and the HCU isolation valves were closed and tagged. The inspector proceeded to the Control Room and noted that control rod #22-11 selector switch was blocked.

The full core display indicated that the control rod #22-11 was at position 48 (full out) and the process computer OD-7, control rod notch positions also indicated that the control rod was at position 48. The reactor was at 44% power and power was constant while the feedwater level control system was being tested.

The inspector questioned the licensed operators and licensee engineers regarding the ability of control rod #22-11 to scram and the status of the shutdown margin for Unit 2. Since the control rod #22-11 was blocked with the HCV isolation valves closed, at position 48, the rod would not scram on a reactor protection system actuation. The licensee acknowledged the inspector's concern, and initiated action to remove the block in order to return control rod #22-11 to an operable status.

The inspector reviewed the blocking permit and the MRF (#2-3-M8509148) which authorized removing control rod #22-11 from service to perform corrective maintenance on a leaking HCU accumulator. The blocking permit was authorized at 10:20 a.m. and was completed (i.e., blocked out of service) by 12:05 p.m. on December 26, 1985. When the shift superintendent was informed of the situation by the inspector, the permit was cleared, the MRF cancelled, and the control rod #22-11 was returned to service by 1:45 p.m. on December 26, 1985. Unit 2 subsequently scrammed at 2:12 p.m. on December 26, 1985 (see detail 4.2.3). Control rod #22-11 did fully insert to notch position 00 as verified by the inspector by checking the full core display rod position and the OD-7 computer printout.

The inspector reviewed system operating procedure S.4.2.C, Removing a Control Rod and Its Hydraulic Control Unit from Service During Reactor Operation, Revision 0, 12/15/72. Step 1 of system procedure S.4.2.C requires placing the control rod in the full-in position. Failure to perform this step prior to removing a control rod from service during reactor power operation is an apparent violation (277/85-40-01).

Technical Specification (T.S.) 3.3.A.2 requires that if a fully or partially withdrawn control rod cannot be moved with control rod drive or scram pressure, continued reactor power operation is allowed if the shutdown margin of T.S. 3.3.A.1 is met. T.S. 3.3.A.1 requires that a sufficient number of control rods be operable so that the core could be made sub-critical with the strongest control rod stuck full out at the most negative condition. The inspector questioned whether or not

shutdown margin could be met with control rod #22-11 inoperable and full out, and the most reactive rod stuck full out at the most reactive core condition. The licensee is evaluating this above condition. The ability to meet shutdown margin requirements is unresolved pending licensee evaluation and NRC review. (277/85-40-05)

The inspector asked if blocking control rods full out was a normal practice. Licensee management indicated that it was not. The Shift Superintendent was unaware of the blocking permit and MRF. The MRF and permit were approved by the Control Operator (licensed reactor operator) and the Shift Supervisor (licensed senior reactor operator). The Unit 2 Reactor Operator was also aware of the control rod #22-11 block. The licensee indicated that the blocking sequence #3-1204, Rev. 2 would be revised to include the requirement that control rods blocked during reactor operations would be fully inserted as required by procedure S.4.2.C. (A blocking sequence is a pre-defined permit for specific equipment blocking.) The licensee is preparing an LER regarding this occurrence.

The leaking accumulator for control rod #22-11 was replaced and returned to service prior to reactor startup on December 29, 1985. The inspector observed the post maintenance control rod scram time testing per ST 10.13 (see detail 7) on December 31, 1985. The control rod scram times met the acceptance criteria of TS 3.3.C.

As noted above one violation and one unresolved item were identified.

4.1.10 On November 6, 1985, the inspector noted that the Containment Atmosphere Dilution (CAD) system oxygen analyzer was inservice because the normal containment oxygen analyzer system was out of service. Since the normal oxygen analyzer had been tested earlier that day and found to be satisfactory, the inspector questioned the cause of inoperability so soon after testing. After discussing the problem with the operators and reviewing completed ST 9.10 "Containment Oxygen Measurement and Analyzing System Functional Test", the inspector determined tnat the failure was caused by water in the sample line. Water in the line occurred due to the temperature difference and the humidity considerations between the torus and Reactor Building. The licensee indicated that they would drain the line more frequently to remove water in the line. The inspector did not observe any more failures of the containment oxygen analyzer system during the report period.

No violations were identified.

4.2 Followup On Events Occurring During the Inspection

4.2.1 Radwaste Building Cable Tray Fire

At 4:02 p.m. on November 10, 1985, smoke was reported by a roving fire watch on the 150 and 165 foot level of the common Rad Waste Building. Unit 2 was at 100% power. The licensee's fire and damage team responded, and discovered a fire in a cable tray and in the diver's cage directly below the cable tray at the 150 foot level of the Rad Waste Building. The fire in the tray was extinguished within a few minutes with portable carbon dioxide and Ansul extinguishers and the fire in the divers cage was extinguished with water. Damage was confined to a small section of the cable tray and associated cables and to the diver's cage. The affected equipment included the liquid radwaste processing system and associated controls. No safety related cables nor equipment were affected. During the fire, voltage on the static inverter dipped causing a Unit 2 EHC and recirculation pump runback to 75% power. Although not required by 10 CFR 50.72, the licensee made an ENS call. The licensee identified the affected cables and replaced the damaged ones. Unit 2 was returned to 100% power on November 11, 1985.

The inspector toured the fire damage area on November 12, 1985, and discussed the fire and damage team response with the licensee. Cable tray RR020 on the 150' level of the Rad Waste Building was damaged by the fire. The inspector independently reviewed the listing of the cables in this tray, and determined no safety related equipment was affected. The cause of the Unit 2 runback to 75% power was de-energization of the reactor recirculation relays 2A-K8A and 2A-K8AX (M-I-S-4, Revision 21) which placed the 60% speed limiter for both recirculation pumps into operation (M-I-S-6, Revision 13). The speed limiters thus decreased recirculation pump speeds to 60% resulting in a reactor power decrease to 75% power.

The licensee has conducted an investigation concerning the fire, however the cause of the fire is currently undetermined. Pending identification of the cause of the fire by the licensee and NRC review, the item is unresolved. (UNR 277/85-40-02)

NRC Inspection 50-277/85-41 further reviews this cable tray fire.

4.2.2 Reactor Scram During Plant Shutdown On November 29, 1985

At 12:02 p.m. on November 29, 1985, Unit 2 scrammed from 33% power while a planned shutdown was in progress. The cause of the scram was turbine stop valve (TSV) closure. A malfunction in the TSV test circuitry apparently caused all 4 TSVs to close, resulting in a reactor scram. The licensee declared an Unusual Event and made an ENS call per 10 CFR 50.72.

The inspector monitored post scram recovery operations from the Control Room. The Control Room recorder traces, computer event log and control room indications were reviewed. The inspector discussed the event with licensee operators and engineers. The inspector reviewed the completed GP-18, "Scram Review Procedure". The scram response was normal. All control rods inserted and the reactor was shutdown. Reactor level initially decreased due to the shrink, however the reactor feed pumps remained on-line and recovered level to normal. During the level decrease, PCIS groups II and III actuated on low reactor water level as required. The PCIS signal was reset, and affected systems were returned to normal.

The licensee determined the cause of the scram to be main turbine stop valve (TSV) closure when #2 TSV closed during troubleshooting causing #1, #3 and #4 TSVs, which are slaves to #2 TSV, to also close. The licensee effected necessary repairs to the TSV controls. The unit remained shutdown for a 4 week maintenance outage. No unacceptable conditions were identified.

4.2.3 Reactor Scram and Feedwater Transient on December 26, 1985

4.2.3.1 Event Summary and Sequence of Events

Event Summary

Unit 2 scrammed from 44% power on low reactor water level at 2:12 p.m. on December 26, 1985. The cause of the level decrease was the loss of "A" reactor feed pump (RFP) on overspeed trip combined with feedwater level control system fluctuations. The "B" and "C" RFPs were being swapped to troubleshoot RFP and level control instabilities identified during the reactor startup on December 25, 1985. During the swapping of "B" and "C" pumps, the RFP check valves slammed three or more times

causing a hydraulic transient in the RFP suction piping. The hydraulic transient resulted in the shearing off of a 1 inch drain line on the 20 inch suction piping to the "C" RFP, causing a steam and water leak in the turbine building. The licensee made an ENS call and declared an Unusual Event due to the unplanned shutdown. Reactor water level decreased to -35 inches (-178 inches is the top of the active fuel). The MSIVs remained open and the "B" RFP recovered water level to normal. When the feedwater leak was reported to the control room, the operators isolated the condensate and feedwater systems, and this action stopped the leak. The RCIC system was manually started to control reactor water level. There was no radioactive release from the leak. No personnel contamination occurred. The main stack release was 0.6% of Technical Specification limit due to the scram and resultant offgas transient (normal release for a scram).

Sequence of Events

Date	Time	Event
December 24	9:56 p.m.	Reactor critical after 3 week outage
December 25	6:05 a.m.	"C" RFP in service - reactor power 10%
December 25	2:15 p.m.	"B" RFP in service - "C" RFP would not control level in automatic
December 25	4:00 p.m.	"C" RFP in service - "B" RFP would not control level in automatic
December 26	5:00 a.m.	Generator synchronized to grid

December 26	11:30 a.m.	"A" RFP in service in manual
December 26	12:30 p.m.	"B" RFP low speed stop (LSS) for motor gear unit (MGU) reset by I&C
December 26	2:00 p.m.	"B" and "C" RFPs being swapped - "A" RFP in auto - reactor at 44% and "B" and "C" RFP check valves begin slamming
December 26	2:11 p.m.	"A" RFP trips on overspeed
December 26	2:12 p.m.	Reactor auto scrams on low water level - Group II/III PCIS
December 26	2:15 p.m.	Feedwater leak in turbine building
December 26	2:19 p.m.	Reactor scram reset
December 26	2:20 p.m.	ENS call to NRC
December 26	2:45 p.m.	Feedwater leak isolated - RCIC controlling water level

4.2.3.2 Initial Licensee Actions and NRC Review

The Senior Resident Inspector was in the Control Room at the time of the transient and scram. Operator post scram and recovery actions were observed. The inspector verified

that emergency trip procedures T-100, Scram and T-99, Post Scram Restoration were followed by the licensee. The trip procedures implementation was coordinated by the Shift Supervisor.

The inspector observed control room indications for reactor water level, reactor power, control rod position, radiation monitoring instrumentation, etc. The inspector verified that the reactor was shutdown by checking source range instrumentation on scale and verifying that all control rods were inserted. The inspector noted that reactor water level decreased to -35" and was recovered to normal level with the "B" RFP. The inspector verified that PCIS Group II/III isolations actuated as required on low reactor water level. No unusual nor unexpected releases occurred.

The inspector observed licensee actions in response to the feedwater leak. The Control Room was informed of a leak in the feedwater line in the turbine building 135 foot level. The licensee initially attempted to isolate the leak by closing the "C" feedwater heater string isolation valves, however the leak continued. The operators then started the RCIC system in manual, and removed the feedwater and condensate systems from service. This action stopped the leak. The inspector observed RCIC system operations and vessel injections to control level.

Within the scope of the review of licensee actions taken during the scram and feedwater leak isolation, no unacceptable conditions were noted.

4.2.3.3 Damage Assessment

The feedwater transient and water hammer caused by RFP check valves slamming resulted in damage to feedwater and condensate system piping and supports. A one inch drain line was sheared off the 20 inch "C" heater string line (18GF reference P&ID M-308, Rev. 20), resulting in a feedwater leak into the turbine

building. The inspector examined the damage to the drain line and feedwater piping in the turbine building 135 foot level at 4:00 p.m. on December 26, 1985. The drain line had been sheared off at the pipe nipple apparently due to movement of the 20 inch feedwater pipe. Most of the water that leaked out collected on the turbine building floor and went into the floor drains to radwaste. Some water did leak down to the 116 foot level of the turbine building where the water was contained. The inspector toured the turbine building 135 and 116 foot levels at 4:30 p.m. on December 26, 1985. The inspector noted that water was contained and radiological surveys were being performed. No spread of contamination occurred. The licensee repaired this drain line on December 27, 1985. The water clean up was completed on December 26, 1985.

The licensee initiated a walkdown of the feedwater and condensate system piping and supports by the corporate mechanical engineering group, test engineers and maintenance ISI group. These walkdowns identified numerous piping and support deficiencies. The deficient items were categorized by priority, responsible group, MRF number and estimated time to repair. The licensee utilized a priority "1" for those items that were required to be repaired prior to restart.

The inspector performed an independent walkdown of selected feedwater and condensate system piping, supports and components. Deficiencies noted by the inspector were cross checked against the licensee's deficiency list. All items noted by the inspector were previously identified by the licensee and included on the licensee's itemized list. The licensee marked up sets of P&IDs and isometric drawings to perform these walkdowns and to document the noted deficiencies. The inspector reviewed the licensee's marked up drawings.

The 18 priority "1" items were repaired by the licensee prior to restart on December 29, 1985. The remaining items are documented on MRFs and will be repaired on a schedule to be determined by the licensee. No violations were identified.

4.2.3.4 Event Cause

On December 26, 1985, just prior to the event, the unit was operating at 44% reactor power with "A" Reactor Feed Pump (RFP) in auto, and "B" and "C" RFPs in manual. The "B" and "C" pumps were being swapped to troubleshoot the Feedwater Level Control System (FWLCS) instabilities experienced earlier during startup. During the swapping process, the discharge check valves on "B" and "C" RFPs began cycling when the operators attempted to close the discharge motor operated valve (MOV) of the "C" pump while bumping open the discharge MOV of the "B" pump. The initiation of the check valve cycling is theorized to be caused by the parallel operation of the "B" and "C" pumps with their discharge MOVs being partially open and moving in opposite directions (the "B" MOV opening and the "C" MOV closing). When the "B" pump introduced increased flow and pressure to the common feedwater header, as a result of the existing manual signal, the "C" discharge check valve slammed closed due to the increased back pressure. Subsequently, when the increasing discharge pressure of the "C" pump opened the "C" discharge check valve, the resulting increased flow and pressure to the common header slammed closed the "B" discharge check valve. Cycling of the check valves continued for a period of time, about one to two minutes, because the closing stroke time of the "C" discharge MOV was long, about three to four minutes. The long MOV stroke time is attributed to the large differential pressures across the valve gate created by the cycling check valves.

The extended cycling of the check valve caused a hydraulic transient and a water hammer in the feedwater piping which in turn caused the damage described in section 4.2.3.3 above.

When the "C" pump speed was subsequently reduced to its low speed stop (LSS), the "C" discharge valve closed and remained closed. The "C" pump flow went to zero which caused the speed of "A" pump which was in auto to go to maximum in response to the level signal from the FWLCS. Subsequently, when the "B"

discharge MOV was fully opened and additional flow and pressure from this pump was introduced to the common feedwater header as a result of the existing manual signal, the "A" discharge check valve closed and the "A" pump flow decreased to zero. When the operator responded by switching the "A" pump control to manual and manually increased its speed, the "A" pump tripped on overspeed. The reactor was at 44% power with one RFP operating in manual control and reactor level decreasing. The resulting low reactor water level transient caused a reactor scram and a Group II and III primary containment isolation.

The cause of the feedwater transient and the resulting scram is attributed partly to lack of adequate procedural guidance for swapping the RFPs. The operator currently uses a combination of two operating procedures for this purpose: (1) S.7.6.B, Placing Second and Third Reactor Feed Pumps In Service, Revision 5 and (2) S.7.6.C, Shutdown of a Reactor Feed Pump Turbine, Revision 3. The operator executes these two procedures concurrently which involves opening of the discharge MOV for the pump being started and closing of the discharge MOV for the pump which is to be subsequently stopped. During the operation, a good deal of operator judgement is required in balancing the flows between the pumps. Operating with 3 RFPs in parallel and in manual control at low power levels (i.e., 44%) with reduced RFP flows is a complex situation for reactor water level control. Imperfect RFP manipulation could induce the check valve cycling such as that which was experienced during the event.

The licensee indicated that RFPs would no longer be swapped at such power levels. Power would be reduced to approximately 25 percent (1 pump operation limit), the pump to be taken out of service would be stopped, the desired pump would be started, and then power would be increased to the original or desired level. By this method, the complex operation of balancing the flows between the 3 pumps during the swapping operation is avoided. The licensee plans to prepare and issue a new or revised operating procedure for the revised mode of operation. Until the new procedure is issued,

by a memo dated December 27, 1985, the licensee issued an interim instruction to the operator not to attempt the swapping operation.

No violations were identified.

4.2.3.5 Corrective Actions

The licensee's short term corrective actions include:

-- Conducted a walkdown of the damaged systems - completed on December 27, 1985.

-- Repaired 18 Priority I items from the list of damages - completed on December 29, 1985. The Maintenance Request Forms (MRFs) for the remaining items are initiated and will to be repaired on a schedule to be determined by the licensee.

-- Issued an Upset Report for the event, including sequence of events, discussion and analysis of the event - completed on December 28, 1985.

-- Issued interim guidance to the operators preventing swapping of the RFPs until the new procedure is issued - completed on December 27, 1985.

The Senior Resident Inspector reviewed the above short term actions in preparation for the plant restart. This review was completed on December 28, 1985. The plant was restarted up on December 30, 1985. The RFPs were tested satisfactorily on December 30 and 31, 1985.

The licensee's long term corrective actions include the preparation and issue of a new or revised operating procedure for exchange of RFPs at intermediate power levels (see sections 4.2.3.4 of this report). Revision of the operating procedure is an unresolved item pending completion of the above action by the licensee and review by NRC (UNR 277/85-40-03).

4.3 Logs and Records

The inspector reviewed logs and records for accuracy, completeness, abnormal conditions, significant operating changes and trends, required entries, operating and night order propriety, correct equipment and lock-out status, jumper log validity, conformance to Limiting Conditions for Operations, and proper reporting. The following logs and records were reviewed: Shift Supervision Log, Reactor Engineering Log, Reactor Operator's Log, Control Operator Log Book and STA Log Book, Night Orders, Radiation Work Permits, Locked Valve Log, Maintenance Request Forms and Ignition Source Control Checklists. Control Room logs were compared against Administrative Procedure A-7, Shift Operations. Frequent initialing of entries by licensed operators, shift supervision, and licensee on-site management constituted evidence of licensee review. No unacceptable conditions were identified.

4.4 Engineered Safeguards Features (ESF) System Walkdown

The inspector performed a detailed walkdown of portions of the RHR system in order to independently verify the operability of the "A" loop of the RHR system. The RHR "A" system walkdown included verifications of the following items:

-- Inspection of system equipment conditions.

-- Confirmation that the system check-off-list (COL) and operating procedures are consistent with plant drawings.

-- Verification that system valves, breakers, and switches are properly aligned.

-- Verification that instrumentation is properly valved in and operable.

-- Verification that valves required to be locked have appropriate locking devices.

-- Verification that control room switch positions, indications and controls are satisfactory.

-- Verification that surveillance test procedures properly implement the Technical Specifications surveillance requirements.

Within the scope of the ESF walkdown, no unacceptable conditions were identified.

5. IE Information Notices Which Require No Response

The inspector reviewed licensee actions regarding IE Information Notice No. 84-70 Supplement 1, dated August 26, 1985, regarding reliance on water level instrumentation with a common reference leg. The above referenced Notice delineates an event at another BWR during reactor startup where plant licensed operators incorrectly concluded that a low level indication on the GEMAC narrow range instrument was erroneous, which led to the undetected inoperability of the two RPS level switch instruments due to reference leg leakage.

The inspector reviewed the Peach Bottom reactor level instrumentation including the following items:

-- type of reference log columns (YARWAY vs. GEMAC) and those instruments which share columns

-- level instrumentation panel device numbering and nomenclature, range, panel indications, local racks and logging requirements

-- level instrumentation calibration procedures and conditions (i.e., calibrated hot or cold)

-- Technical Specification sections 3.1.1, 3.2.A,B,F,G requirements and instrumentation functions (i.e., indication, alarm, device initiations, etc.)

-- Licensed operator awareness and knowledge of level instrumentation and associated formal training

The inspector interviewed selected reactor operators and determined they were knowledgeable of reactor level instrumentation. During review of licensed operator training lesson plan, LOT-050, Reactor Vessel Instrumentation, November 7, 1984, minor errors were noted in two of the transparencies. These transparencies describe how to correct indicated level to actual level for reactor conditions other than normal operating temperature and pressure. The inspector discussed these training lesson plan minor errors with licensee training and operating personnel who indicated corrections would be made. In addition, during discussions with licensee operational personnel, it was indicated that reactor level indication panel nomenclature is being upgraded to identify which instruments share common reference legs. The upgrade is part of the overall control room upgrade. No violations were identified.

6. Review of Licensee Event Reports (LERs)

6.1 LER Review

The inspector reviewed LERs submitted to NRC:RI to verify that the details were clearly reported, including the accuracy of the description and corrective action adequacy. The inspector determined whether further information was required, whether generic implications were indicated, and whether the event warranted on-site followup. The following LERs were reviewed:

LER No. LER Date Event Date	Subject
2-85-21 November 27, 1985 September 30, 1985	Motor Driven Fire Pump out of service
*2-85-22 November 15, 1985 October 17, 1985	Reactor scram and PCIS due to loss of reactor feedwater pumps
2-85-23 November 21, 1985 October 22, 1985	Electrical Separation Criteria
*2-85-24 December 6, 1985 November 3, 1985	Primary Containment Isolation Valves

6.2 On-Site-Followup

For LERs selected for on-site followup and review (denoted by asterisks above), the inspector verified that appropriate corrective action was taken or responsibility assigned and that continued operations of the facility was conducted in accordance with Technical Specifications and did not constitute an unreviewed safety question as defined in 10 CFR 50.59. Report accuracy, compliance with current reporting requirements and applicability to other site systems and components were also reviewed.

6.2.1 LER 2-85-22 concerns a reactor scram on low reactor level from 100% power due to loss of reactor feedwater. This event was reviewed in NRC Inspection 277/85-29. No inadequacies were noted relative to this LER.

6.2.2 LER 2-85-24 concerns an inoperable containment isolation valve and subsequent failure to follow the required Technical Specification action.

At 3:00 p.m. on November 1, 1985, ST 6.2, PCIS Normally Open Valves, Revision 12, was performed unsatisfactorily due to failure of two of the seven containment oxygen analyzer solenoid valves, SV-2671A and SV-2671C. These solenoid valves are normally open 1/2 inch valves located in the torus room which fail closed on a loss of power.

A redundant solenoid valve (SV-2978A thru G) is in series with each of the seven above mentioned valves (2671A thru G). The redundant solenoid valve is located in the reactor building. Reference P&ID M-367, Containment Atmosphere Control, Revision 17. All 14 of these solenoid valves are listed in TS Table 3.7.1 as primary containment isolation valves. Operation of valve SV-2671A caused blown fuses and therefore the valve failed the ST 6.2. SV-2671C failed the ST 6.2 due to failure of the valve to isolate flow.

When the inoperable valves were discovered, the licensee implemented ST 5.3, Inoperable Isolation Valve Position Daily Log, Revision 4 and applied a permit (#2-85-318) to block the two manual valves (upstream of SV-2671A and C) as required by TS 3.7.D.2 and TS 4.7.D.2. MRFs were also initiated for SV-2671A (2-7-M8507623) and for SV-2671C (2-7-M8507676).

The licensee repaired SV-2671A by replacing the solenoid coil and the valve internals. At 1:35 a.m. November 3, 1985, the permit (#2-85-318) which blocked the two manual valves for both SV-2671A and C was cleared, and the manual valves were opened. However, SV-2671C had not been repaired and therefore remained inoperable. At 11:30 a.m. on November 4, 1985, the licensee's STA noted that valve SV-2671C was inoperable, however the TS 3.7.D.2 action requirement to isolate the line was not being implemented. At 11:45 a.m., the licensee initiated a permit (#2-85-319) to block the SV-2671C manual valve and implemented ST-5.3 for the inoperable containment isolation valve to comply with TS 3.7.D.2 and TS 4.7.D.2. In addition, the licensee initiated a permit (#2-85-320) to block the SV-2671A, because

valve operation was still blowing fuses and the valve failing in the closed position. The licensee was in non-compliance with TS 3.7.D.2 (isolating the line with an inoperable containment isolation valve) and TS 4.7.D.2 (daily recording the position of another valve in the line having the inoperable valve) for approximately 34 hours.

The inspector reviewed the above referenced two MRFs and three blocking permits, the completed ST 6.2 and ST 5.3, and discussed the event with the licensee. The cause of the event was reported by the licensee in the LER as failure of the on-shift licensed operator to adequately ensure that maintenance was completed on both solenoid valves SV-2671A and C prior to clearing the blocking permit #2-85-318. This operator was counselled on his actions. The entire operating shift was instructed that permits used as administrative controls should include specific purpose and conditions necessary for removal of the permit. The inspector verified these licensee corrective actions by conducting interviews with licensed operators and spot checks of shift permits.

Failure to follow TS 3.7.D.2 and TS 4.7.D.2 for inoperable containment isolation valves is a violation of Technical Specifications, however because the NRC wants to encourage and support licensee initiative for self-identification and correction of problems no notice of violation is issued since (1) the licensee identified the problem, (2) it fits Severity Level IV or V, (3) the violation was reported as an LER, (4) measures were taken to correct the problem and additional measures were taken to prevent recurrence, and (5) it is not a violation that could reasonably be expected to have been prevented by correction of a previous violation. In addition, this event is mitigated by the operability of redundant isolation valves, SV-2978A and C, in the 1/2 inch lines containing the SV-2671A and C valves. The inspector had no further questions at this time.

7. Surveillance Testing

The inspector observed surveillance tests to verify that testing had been properly scheduled, approved by shift supervision, control room operators were knowledgeable regarding testing in progress, approved procedures were being used, redundant systems or components were available for service as required, test instrumentation was calibrated, work was performed by qualified personnel, and test acceptance criteria were met. Parts of the following tests were observed:

-- ST 6.14, River Temperature Monitoring, Revision 9, 1/3/84, performed on November 26, 1985.

-- ST 9.12, Reactor Vessel Temperature, Rev. 7, 8/10/84, performed once per shift while shutdown.

-- ST 9.12C, Reactor Vessel Head Flange Temperature Surveillance, Rev. 0, 9/1/83, performed hourly while the vessel head is tensioned and less than 212 degrees F.

-- ST 9.17, Reactor Coolant Leakage Test, Revision 5, 6/20/85, performed on November 26, 1985.

-- ST 2.5.14, Functional Check of the RPS "A" Card File, Revision 9, 3/12/84, performed on December 3, 1985.

-- ST 2.5.16, Functional Check of the RPS "C" Card File, Revision 10, 6/20/84, performed on December 3, 1985.

-- ST 10.13, CRD Scram Insertion Timing of Selected Control Rods, Revision 3, 10/11/85, performed on CRD's 22-11 and 30-27 on December 31, 1985.

In addition, a review of the following completed surveillance tests was performed:

-- ST 15.80.5B-3, Functional Test of U/3 165' Radwaste Bldg. Smoke Detectors, Rev. 0, 9/22/83, performed on February 7, 1984 and January 19, 1985.

-- ST 15.80.5B-2, Functional Test of U/2 165' Radwaste Bldg. Smoke Detectors, Rev. 0, 9/22/83, performed on February 7, 1984 and January 19, 1985.

-- ST 15.80.5A-2,3, Calibration Test of the 165' Radwaste Bldg. Smoke Detectors, Rev. 0, 9/27/85, performed on July 24, 1985 and September 11, 1984.

-- ST 6.2, PCIS Normally Open Valves, Revision 12, 7/26/85, performed on November 1, 1985.

-- ST 5.3, Inoperable Isolation Valve Position Daily Log, Revision 4, 10/30/84, performed on November 1, 2, 4-7, 1985.

No inadequacies were identified.

8. RHR Pumps

Based on impeller wear ring failures on the Unit 3 RHR pumps (reference NRC Inspection 278/85-41), the licensee inspected the internals of the 2A and 2C RHR pumps during the period December 1-3, 1985. In addition, the 2A RHR was scheduled to be inspected during the December, 1985 outage as a result of flow and pressure abnormalities (reference NRC Inspection 277/85-29, 278/85-33).

The results of the licensee's inspections (memo dated December 6, 1985) of the 2A and 2C RHR pumps were as follows:

-- The 2A RHR pump impeller wear rings were intact, and initially showed no signs of cracking. Subsequent visual inspections revealed surface cracks on the impeller wear rings. The impeller suction vanes were much thicker than the normal feathered vanes on other RHR pumps.

-- The 2C RHR pump impeller showed signs of mechanical wear on the suction vanes and pump internals. No cracked wear rings were identified.

The 2A RHR pump impeller and motor had been replaced in June, 1982, due to motor rubbing and pump seal failure. The 2C RHR pump had the original impeller.

The inspector examined the 2A RHR pump impeller on December 12, 1985. The inspector noted that the impeller wear rings were intact and that the suction vanes were not feathered as were the other RHR impellers. On December 30, 1985, the inspector examined the 2A RHR pump impeller lower wear ring. Several surface cracks about 1/2 inch long were visible to the naked eye.

The licensee repaired both the 2A and 2C RHR pumps with replacement impellers. The 2C RHR pump was tested satisfactorily on December 10, 1985, and the 2A RHR pump on December 13, 1985. The inspector reviewed the results of ST 6.8, RHR "A" Pump Valve, Flow and Unit Cooler Functional, Revision 29, performed on December 20, 1985. ST 6.8, for pumps 2A and 2C, demonstrated that acceptance criteria for flow and pressure were met.

Based on the results of the six RHR pump inspections (4 pumps on Unit 3; 2A and 2C on Unit 2) and based on the 2B and 2D RHR pump performance, the licensee decided not to inspect the 2B and 2D RHR pumps prior to Unit 2 restart. The inspector questioned the licensee's basis for this decision and a NRC/Licensee conference call was held on December 13, 1985 to discuss the basis for restarting Unit 2. The licensee stated that only one RHR pump (3C) experienced a catastrophic inservice failure and the failure occurred after three days of pump run with high bearing temperatures that were not noticed. The six RHR pumps were repaired with either a new or a repaired impeller and tested satisfactorily. The licensee committed to the following for the 2B and 2D RHR pumps:

-- Increase the frequency of ST 6.9, which includes testing and monitoring pump flow, discharge pressure and running current, from monthly, as currently required by the Technical Specifications, to weekly.

-- Conduct 2B and 2D RHR pump internal inspections within 120 days after Unit 2 startup.

-- Monitor bearing temperatures during pump operation.

The inspector reviewed Unit 2 RHR pump test data since 1983. The test data was compiled by the licensee based on surveillance test results. The following parameters were trended in tabular format and graphically:

-- pump differential pressure (PSI)

-- motor amps

-- pump vibration (mils)

-- pump flow (gpm)

The inspector discussed the RHR pump test data with the licensee. The inspector asked if any trend information could be detected. The licensee noted a degraded performance in 2A RHR pump (reference NRC Inspection 277/85-29). In addition, the 2D RHR pump was in the "alert" range for differential pressure for the ASME Section XI ISI criteria since the 1984-1985 refueling. The "alert" range is defined as between 0.90 and 0.93 of the reference value of 250 psi differential pressure (225 to 232.5 psi). The 2D RHR pump met the TS flow requirements of 11,500 gpm. As of May 26, 1985, the licensee doubled the 2D RHR pump test frequency required by ASME Section XI, paragraph IWP-3230.

At 6:45 a.m. on December 21, 1985, the 2D RHR pump experienced several motor overcurrent alarm conditions while in the shutdown cooling mode of operation. The licensed reactor operator stopped the pump and the licensee inspected the pump and motor for damage. The motor inspection identified no damage; however, the pump lower impeller wear ring was broken and off the impeller, and a 6" section was missing. The licensee conducted a search for the missing section and found nothing. The licensee concluded that the missing piece was essentially ground away by impeller rubbing. The licensee repaired the 2D RHR pump with a replacement impeller with new wear rings.

The inspector discussed the overcurrent condition and event with the licensee operators. The operators observed a motor current of 335 amps on control room indications. The normal running current is 240 amps. The inspector reviewed alarm card #203D-3 and verified that the operators took appropriate immediate corrective actions on the alarm condition.

The inspector reviewed the surveillance test data for the 2D RHR pump prior to failure. The test, ST-6.9F, was run on December 19, 1985, and the results were satisfactory. The inspector reviewed operating logs and determined the 2D RHR pump had been run on shutdown cooling after ST 6.9F completion from 11:45 p.m. on December 19, 1985, to 6:45 a.m. on December 21, 1985 when the overcurrent alarms occurred. The run time was 31 hours.

The inspector observed portions of the 2D RHR pump and motor maintenance on December 23, 1985. The maintenance was being performed in accordance M10.1, Residual Heat Removal (RHR) Pump Maintenance, Revision 4. The 2D RHR pump was repaired, tested and declared operable on December 24, 1985. The inspector reviewed the ST-6.9 test results for the 2D RHR pump and all test acceptance criteria were met.

The licensee is currently drafting a formal report addressing the RHR pump failures. The report will include maintenance findings and evaluations, engineering evaluations and historical test results, repair activities and conclusions.

The inspector will continue to follow the RHR pump testing and inspection plans for the 2B RHR pump. The inspector will also review the licensee's formal report on the RHR pumps when it is completed (IFI 277/85-40-04).

9. Radiation Protection

During this report period, the inspector examined work in progress in both units, including the following:

-- Health Physics (HP) controls

-- Badging

-- Protective clothing use

-- Adherence to Radiation Work Permit (RWP) requirements

-- Surveys

-- Handling of potentially contaminated equipment and materials

The inspector observed individuals frisking in accordance with Health Physics procedures. A sampling of high radiation doors was verified to be locked as required. Compliance with RWP requirements was verified during each tour. RWP line entries were reviewed to verify that personnel had provided the required information and people working in RWP areas were observed to be meeting the applicable requirements. No unacceptable conditions were identified.

10. Physical Security

The inspector monitored security activities for compliance with the accepted Security Plan and associated implementing procedures, including: operations of the CAS and SAS, checks of vehicles on-site to verify proper control, observation of protected area access control and badging procedures on each shift, inspection of physical barriers, checks on control of vital area access and escort procedures. No inadequacies were identified.

11. In-Office Review of Public and Special Reports

The inspector reviewed the following:

-- Report of Plant Startup Following Sixth Refueling Outage, dated October 28, 1985

Within the scope of this review, no unacceptable conditions were identified.

12. Mechanical and Hydraulic Snubbers

Based on the high number of functional test failures (47 of 71) of mechanical snubbers on Unit 3, the licensee is currently replacing Unit 2 mechanical snubbers, except for six recently installed snubbers on the recirculation system pumps and on the RBCCW system. The replacement mechanical snubbers are from Limerick and have never been used.

The inspector determined that the licensee has also performed a visual inspection of the snubbers per ST.9.15-2B on December 1-3, 1985, and has made a preliminary assessment that identifies five mechanical and three hydraulic snubbers as inoperable. Final determination of operability status was performed by corporate engineering.

The inspector was concerned that the removed snubbers were not to be tested until a later date and that all snubbers removed should be tested for freedom of motion since they could have caused damage to the supported piping or component if locked. The licensee had a similar concern and was performing tests for freedom of motion through the entire stroke range for all of the removed mechanical snubbers. Additionally, the licensee initiated plans for testing all removed mechanical snubbers. Snubber testing was completed on December 19, 1985. The test results were as follows:

Snubbers		Failure Mechanism(s)		
Size	Number	Acceleration Test	Drag Test	Damaged
PSA-35	1	0	0	0
PSA-10	44	15	0	0
PSA-3	8	0	3	0
PSA-1	1	0	0	1
PSA-1/2	8	0	0	4

The inspector reviewed the vendor test documentation for snubbers transferred from Limerick and for the six recently installed on the recirculation system pumps. No inadequacies were identified.

The inspector reviewed the engineering safety evaluation dated December 20, 1985, performed by the licensee regarding snubber failures as required by TS 4.11.D.6 The evaluation concluded that the inoperability of noted snubbers had no adverse effects on piping systems and components and did not result in an adverse condition. No inadequacies were identified.

13. Unresolved Items

Unresolved items are items about which more information is required to ascertain whether they are acceptable violations or deviations. Unresolved items are discussed in details 4.1.9, 4.2.1 and 4.2.3.5.

14. Inspector Follow Items

Inspector follow items are items for which the current inspection findings are acceptable, but due to on-going licensee work or special inspector interest in an area, are specifically noted for future follow-up. Follow-up is at the discretion of the inspector and regional management. An inspector follow item is discussed in Detail 8.

15. Management Meetings

15.1 Preliminary Inspection Findings

A verbal summary of preliminary findings was provided to the Assistant Station Superintendent at the conclusion of the inspection. During the inspection, licensee management was periodically notified verbally of the preliminary findings by the resident inspectors. No written inspection material was provided to the licensee during the inspection. No proprietary information is included in this report.

15.2 Attendance at Management Meetings Conducted by Region-Based Inspectors

The resident inspectors attended entrance and exit interviews by region-based inspectors as follows:

Date	Subject	Inspection Report No.	Reporting Inspector
October 28 (Ent) November 1 (Exit)	Fire Protection - Alternate Safe Shutdown Modifications	85-39	Pullani

Date	Subject	Inspection Report No.	Reporting Inspector
November 13 (Ent)	Cable Tray Fire	85-41	Krasapoulos
November 25 (Ent) November 27 (Exit)	Security	85-43	Bailey
November 14	Enforcement Conference - Transportation	85-42	Pasciak