U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-387/86-24; 50-388/86-26

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

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: October 15, 1986 - December 1, 1986

Inspectors: L. R. Plisco, Senior Resident Inspector
J. Stair, Resident Inspector
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Approved By: J. T. Wiggins 1/9/87
J. Wiggins, Chief, Reactor Projects Section 1B, DRP — date

Inspection Summary:

Areas Inspected: Routine resident inspection of plant operations, licensee events, Unit 2 First Refueling Outage activities, allegation followup, open item followup, surveillance, and maintenance.

Results: Radioactive waste spill occurred in the Radwaste Building (Detail 3.3); an inadvertent ESF actuation occurred due to technician error (Detail 3.4); airborne contamination occurred in the Radwaste Building due to ventilation system problems (Detail 3.5); a radioactive spill occurred in Unit 2 RHR room due to two mispositioned valves (Detail 3.6); three waterhammer events occurred in the RHR and Feedwater systems (Detail 3.7); discrepancies were identified in the RHRSW system during flow verifications (Detail 5.3); debris was found in the Unit 2 containment instrument gas system (Detail 6.1); primary containment hatches were not installed properly (Detail 6.2); containment radiation monitor pumps were found to leak excessively (Detail 8.0); and, employee concerns related to problems with raising safety concerns to supervisors was reviewed (Detail 9.0).

## DETAILS

### 1.0 Followup on Previous Inspection Items

#### 1.1 (Closed) Violation (387/83-34-01): Drywell Head Seal Valve Not Verified Closed

During a control room review in October 1983, the inspector noted that the Unit 1 drywell head seal test connection valve (1-57-014) had not been verified shut as required by Technical Specification surveillance requirement 4.6.1.1. The Technical Specification required that the valve be checked shut at least once per 31 days in Operating Conditions 1, 2 and 3.

The valve had not been verified shut for several reasons. First, the valve is located in the reactor well and is normally not accessible, since it is covered by shield plugs. Secondly, the valve had been removed from the normal surveillance procedure 50-59-003, because the surveillance requirement was entered into a new procedure 50-59-009. However, the new procedure had not been performed since it was not properly entered into the surveillance tracking system and thus was not scheduled.

LER 83-146 was submitted by the licensee to describe the event and discuss corrective actions. The licensee performed a review of all 31 day operating surveillance procedures to ensure they were properly scheduled, and no further discrepancies were identified.

The inspector reviewed the correct surveillance procedure, monthly Verification of the Reactor Cavity Containment Penetration, and verified that it is properly scheduled in the tracking system.

#### 1.2 (Closed) Inspector Followup Item (388/85-26-01): Replacement of Yarway Valves - Part 21 Report

On September 26, 1985, Yarway Corporation provided a notification of a defect to Region I in accordance with 10 CFR Part 21. The notification stated that a cracked stem assembly was detected in a 3/4 inch Yarway Welbond valve at a non-nuclear facility. Yarway concluded that voids were present in the bar stock used to manufacture the stems. Yarway notified the licensee in subsequent correspondence that 24 valves with potentially defective stems were supplied to the facility. Non-conformance Report (NCR) 85-0462 was issued to document the condition of the valves.

Eleven of the subject valves were found in the warehouse and returned to Yarway for replacement on February 7, 1986. Twelve valves were found installed in the Unit 2 RHR, RHR room cooler, RWCU, and Unit 1 offgas systems. The valve stems were replaced on the above valves under individual work orders during the Unit 2 first refueling outage. One valve could not be located. Plant records were reviewed to verify that the valve had not been issued by the warehouse and had not been installed in the plant. The valve could not be found in the warehouse. The licensee believes that the valve was discarded for an unknown reason during construction. The NCR was closed on October 3, 1986.

The inspector reviewed the completed NCR report, vendor correspondence, and the returned material notice for the spare valve replacement. No unacceptable items were identified.

1.3 (Closed) Violation (387/86-02-01; 388/86-01-01): Configuration Change Made to Seismically Qualified Panels Without an Approved Safety Evaluation

During a tour of the Unit 1 and Unit 2 reactor buildings in January 1986, the inspector noted that the panel doors for the Reactor Coolant Pressure Boundary Leak Detection System (C-227) and the Containment Atmosphere Analyzer (C-226) were removed or hanging open. These panels are seismically qualified, and a violation was issued since a written safety evaluation in accordance with 10 CFR 50.59 was not performed to provide the basis for the changes. Since the panel doors were installed during the seismic qualification testing, the removal of the doors should have been evaluated to determine the impact on the panel qualification.

Engineering Work Request (EWR) MIS 86-0043, which was completed on February 7, 1986, stated that Wyle Labs seismically qualified the panels with a closed door, and that the door was felt to have sufficient weight and stiffness to potentially affect the dynamic characteristics/response of the panel. This EWR stated that the doors should be reinstalled and left in the closed position to ensure the seismic qualification.

An additional EWR concerning the door panels, MIS 86-0203, was completed on April 7, 1986, which performed a safety evaluation of the panel with the doors off and discussed a long term resolution to the panel internal heating problems. The additional review was required because reinstallation of the doors was not possible without causing damage to the containment radiation monitor (CRM) pumps due to heating.

The EWR concluded that complete removal of the doors would not degrade the seismic qualification of the panels. If the doors remained installed, they are required to be kept closed, since evaluation of the potential swinging and impacting could not be accurately accounted for in the calculations. The long term solution to the heating problem is still being evaluated under EWR IREIR 100993. The EWR reiterated that future alterations to Q equipment requires prior approval from NPE.

On April 17, 1986 the I&C supervisor issued a memorandum to the individual station section heads, associating panel door integrity with seismic qualification. The memorandum stated that an evaluation by engineering is necessary prior to seismic panel door removal.

The inspector reviewed the associated EWR's, internal memorandums, and the violation response dated May 5, 1986. No unacceptable items were identified.

1.4 (Closed) Inspector Followup Item (388/86-11-02): RCIC Pump Discharge Valve Failure

On July 2, 1986, the Unit 2 RCIC pump discharge valve (HV-249-F013) was found failed in the closed position, and RCIC was declared inoperable. The valve was repaired, but a Pump and Valve Inservice Test (IST) Program relief request was granted by NRR on July 11, 1986, to allow performance of an alternate leak test to quantify leakage rather than performing an LLRT. Performance of an LLRT would have required a shutdown.

On July 17, the unit was manually scrammed due to increased unidentified reactor coolant system leakage in the drywell. During the forced outage, the LLRT of the RCIC pump discharge valve was performed satisfactorily. The inspector reviewed the results of surveillance procedure SE-259-026, LLRT of RCIC Valves HV-249F013 and 2-49-020 and Feedwater Check Valve HV-241F032A, which was completed on July 21. The measured leakage was added to the existing penetration leakage and was verified to be less that 0.6 La.

2.0 Review of Plant Operations

2.1 Operational Safety Verification

The inspector toured the control room daily to verify proper manning, access control, adherence to approved procedures, and compliance with LCOs. Instrumentation and recorder traces were observed and the status of control room annunciators was reviewed. Nuclear Instrument panels and other reactor protection systems were examined. Effluent

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

The inspector reviewed shift supervisor, plant control operator and nuclear plant operator logs covering the inspection period. Sampling reviews were made of tagging requests, night orders, the bypass log, Significant Operating Occurrence Reports (SOORs), and QA nonconformance reports. The inspector observed several shift turnovers during the period.

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, cable spreading rooms, penetration areas, reactor and turbine buildings, diesel generator building, ESSW pumphouse, the security control center, and the plant perimeter. During these tours, observations were made relative to equipment condition, fire hazards, fire protection, adherence to procedures, radiological controls and conditions, housekeeping, security, tagging of equipment, ongoing maintenance and surveillance and availability of redundant equipment.

On November 20, 1986, the inspector noted a flammable material storage locker on the refueling floor that was not grounded, in conflict with the manufacturer's instructions on the front of the locker. The licensee indicated that manufacturer grounding recommendations vary, but that an ungrounded cabinet was acceptable as long as flammable material is not dispensed from within the cabinet. The inspector contacted an NRC Region I fire protection specialist who agreed with the licensee's position. The licensee stated that flammable liquids are only dispensed in the Unit 1 storeroom. Small containers that could be used to dispense liquids from inside the cabinets are not used onsite. The inspector and the Site Fire Protection Engineer checked flammable storage cabinets in the control structure, both unit reactor buildings, and a turbine building and found no evidence of dispensing containers in the cabinets. All cabinets were properly vented. The inspector had no further questions.

## 3.0 Summary of Operating Events

### 3.1 Unit 1

Unit 1 operated at or near full power for most of the inspection period. Scheduled power reductions were conducted throughout the period for control rod pattern adjustments, surveillance testing, scheduled maintenance, and condenser in-leakage testing.

At 6:30 a.m. on October 22, 1986, approximately 600 gallons of liquid radioactive waste was spilled on the floor of the Radwaste Building. The spill was contained in the Radwaste Building and there was no offsite release or personnel contamination. (See Detail 3.3).

At 11:54 a.m. on November 13, 1986, an unplanned refueling floor ventilation isolation occurred during the performance of a surveillance test when an I&C technician inadvertently placed the wrong radiation monitor trip unit into trip test. The systems were immediately restored. (See Detail 3.4)

At 10:30 a.m. on November 20, 1986, while in the process of cleaning radwaste filters, particulate activity from the filters became airborne and contaminated an area of approximately 10,000 square feet on 3 levels of the Radwaste Building. There was no offsite release. The areas were decontaminated and the licensee is investigating the cause. (See Detail 3.5)

### 3.2 Unit 2

Unit 2 entered Operational Condition 2 at 2:15 a.m. on October 22, 1986, following completion of its first refueling outage, which began on August 9, 1986. Criticality was achieved at 8:45 a.m. on the same day. Two manual 'black and white' scrams were conducted from low power to perform scram time testing on October 23 and 24. Refueling outage activities are discussed in Detail 6.0.

At 4:00 p.m. on October 22, 1986, during testing of the High Pressure Coolant Injection (HPCI) system, contaminated water was spilled into the A RHR pump room because of two mispositioned drain valves in the steam condensing mode piping. (See Detail 3.6)

While performing a reactor startup on October 24, following the first black and white scram, it was determined that the RHR testable check equalizing valve (HV-251-122B) on the B loop was leaking by its seat. During troubleshooting of the valve, a waterhammer occurred in the system, damaging a hanger. Following this event, the second black and white scram was initiated.

Following the second manual scram on October 24, a short maintenance outage was conducted to perform repairs on the B RHR loop testable check valve (2F122B). While proceeding to Operational Condition 4 to perform the repairs, a suction valve to the B reactor feed pump was opened causing a waterhammer since the system was partially drained. The A RFP was forced out of alignment and three hangers and an anchor were damaged. The unit reached Condition 4 at 5:25 a.m. on October 25. Detail 3.7 further discusses the waterhammer events.

The unit was placed in the Operational Condition 2 at 1:15 p.m. on October 27, 1986, following repairs to the damaged snubbers and realignment of the feed pump. Criticality was achieved at 4:00 p.m. the same day. The reactor startup was temporarily delayed due to the discovery of loose nuts on the suppression pool and CRD removal containment hatches. The nuts were properly tightened and LLRTs were performed. (See Detail 6.3). The unit was synchronized to the grid at 1:53 p.m. on October 29, 1986.

On October 30, at approximately 4:00 p.m., Unit 2 was shutdown from 51 percent power due to failure to the 'E' TIP Indexing mechanism. Following repairs, the unit returned to Operational Condition 2 on October 31. The unit was synchornized to the grid at 6:00 p.m. on November 1, 1986.

During the startup, reactor core noise and stability tests were performed to demonstrate stability of the new Exxon 9x9 fuel assemblies. Following completion of the power ascension and post refueling startup testing, the unit reached 100 percent power at 11:00 p.m. on November 6. Single loop operation testing was performed on November 8.

### 3.3 Radioactive Waste Spill in the Radwaste Building

During routine processing of Liquid Radioactive Waste (LRW) at 6:30 a.m. on October 22, the 'B' Waste Mixing Tank not available light, and the Chemical RW Sump Hi-Hi Level alarms were received in the Radwaste Control room. An operator investigating the reason for the alarms discovered water flowing out from under the Decontamination Room door on the 646 foot elevation of the RW Building. All radwaste processing activities were terminated and the Waste Mixing Tank Room was entered where several inches of water were found on the floor.

Further investigation found that the 'B' filter cake discharge valve (HV-06227B) was not fully closed, even though it indicated closed on the LRW filter panel. HV-06227 A&B are 16 inch, 4-way solenoid, air operated knife gate valves at the outlet of the A&B LRW filters in

line to the A&B waste mixing tanks and are used to transfer sludge buildup from the filters to the waste mixing tanks for processing. An operator had previously isolated the valve's air supply and vented the valve operator's accumulator with the valve in the closed position. Although a high level alarm was received on the local panel at elevation 646' for the 'B' waste mixing tank, no reflash of the trouble alarm was received in the RW Control Room.

Inventory of the LRW collection and sample tanks indicated that approximately 8,000 gallons of waste water was transferred through HV-06227B to the 'B' waste mixing tank which overflowed to the catch basin and floor drains. A drain from the catch basin directs waste water to the RW Bldg. Chemical RW Sump, which in turn pumps waste water to the chemical waste tank and also has an overflow to the RW Bldg. LRW sump. The increase in level in the chemical waste tank accounted for 3,500 gallons of the waste, while it's estimated that approximately 3,000 gallons was returned to the LRW collection tanks from the LRW sump. Approximately 1,000 square feet of floor space on the 646 foot elevation was contaminated due to backup of floor drains and overflow of the catch basin and sumps with an estimated 600 gallons present in the Decontamination Room. Maximum radiation levels recorded were 120mR/hr immediately following the spill with average contamination levels of 25K DPM/100 sq.cm. Decontamination activities were promptly initiated and access to the area was restored.

The air supply to HV-06227B was restored and the valve was visually observed to move approximately 1/4 inch in the closed direction. The licensee believes that system pressure on this type of valve may cause it to lift off its seat when air is removed from its operator. Leakage through HV-06227 A&B has been observed by the licensee on previous occasions when the valves have not been mechanically blocked closed. Although it was known by some of the operators that these valves need to be mechanically blocked to prevent leakage, it was not documented or proceduralized. Mechanical blocking is presently only imposed on those valves which are to be placed in a position other than that in which they fail. The operator who removed the air supply from the valve operator assumed by the system drawing that the valve would fail closed on removal of the air supply. P&ID M-162 incorrectly indicates the valve operator as fail closed on loss of air since it shows a spring on the valve operator which does not actually exist. The valve actually fails-as-is on loss of air and fails closed on loss of power with air available. The licensee is currently evaluating the situation to determine if this drawing discrepancy is an isolated case or exists on any other P&IDs and is initiating a program to correct the discrepancies.

A similar problem with the system drawings was identified after an event occurred on December 9, 1983, in which contaminated water spilled out of the Unit 1 precoat supply line through an air operated isolation valve, which had opened due to back pressure on the valve. The licensee had disconnected the air supply from this valve to preclude inadvertent operation since the P&IDs indicated that the valve failed closed on loss of air when in fact the valve failed-as-is on loss of air. The licensee initiated a review of P&IDs at that time which determined that the valves failed closed electrically. Electrical power, however, had been previously removed from the valve solenoids. The licensee modified the P&IDs by replacing the F.C. (fails closed) with a note which states the valves actual failure mechanism, however, valves indicating a spring on the air operator were not altered.

Although appropriate actions have been taken with respect to cleaning up the spills and correcting the P&IDs. These two events indicate a weakness in the control of air operated valves when used for blocking points. In both cases, valves appear to have opened due to system pressure on the disc, allowing contaminated water spills.

The licensee's corrective actions will be reviewed in a subsequent inspection. (387/86-24-01)

3.4 Inadvertent ESF Actuation during Surveillance Testing

At 11:54 a.m. on November 13, an unplanned Zone III ventilation isolation on high radiation occurred during the performance of Surveillance Test Procedure SI-079-225. The 'B' Trains of Standby Gas Treatment System, Control Room Emergency Outside Air Supply System, and Reactor Building Recirculation Fans automatically started as designed. The isolation occurred when an I&C technician inadvertently placed the Refuel Floor Shaft Exhaust Radiation Monitor Trip Unit into trip test when the procedure required the Refuel Floor High Exhaust Monitor to be placed into trip test. The systems were restored to normal and an ENS call was made per 10 CFR 50.72.

The inadvertent actuation was partly attributable to inadequate labeling of the Radiation Monitors. Step 6.2.4 of SI-079-225 refers to monitor D12-K615B when direction is given to place the test switch in the trip test position, but the radiation monitor is not labeled by this number. The label lists the descriptive function only. The monitor which was accidentally placed in trip test is located adjacent to the proper unit and is similarly labeled. The licensee is planning to label all radiation monitor indicators and trip units in accordance with the ongoing plant labeling program,

which includes adding identification numbers. In addition, the cause, evaluation, resolution and action to prevent recurrence was reviewed with all I&C personnel.

3.5 Airborne Contamination in Radwaste Building

At 10:30 a.m. on November 20, while cleaning radwaste filters in the Radwaste Building, particulate activity from the filters became airborne and contaminated an area of approximately 10,000 square feet on 2 levels of the radwaste building. Twenty-eight individuals were in the building at the time of the event, seven of whom had been working on the filters and were dressed in protective clothing and respirators. In addition, 5 other individuals made entries into the building sometime during the period. Nine individuals were identified with contamination on their shoes. Floor contamination levels averaged 2K to 4K DPM/100 sq. cm. The highest contamination detected was 10K DPM/100 sq cm. In addition, a trailer loaded with a Hittman liner in the truck bay was contaminated to levels of 1K to 3K DPM/100 sq. cm. The tractor and area outside of the open door were not contaminated. Work was stopped in the Radwaste Building and decontamination efforts begun immediately. Airborne samples recorded 2.7 MPC in the area where the filters were being cleaned and 0.14 MPC near the truck bay. The licensee gave all 26 individuals not in respirators at the time of the event whole body counts. No internal contamination was identified.

Two contributing factors to the cause of the event are being evaluated. One is that a change in ventilation flow may have occurred when the truck bay door was opened to allow the liner to be brought in, and the second is that a ventilation barrier which was erected in the northeast corner of the radwaste building may have affected the ventilation flow path.

The licensee is restricting evolutions in the radwaste building until an evaluation of the radwaste building ventilation system is completed.

The licensee's corrective actions will be reviewed in a subsequent inspection. (387/86-26-02)

3.6 Contaminated Water Spill (Unit 2)

At 4:00 p.m. on October 22, with Unit 2 starting up at 120 psig and 346°F, HPCI was being aligned to perform the 150 psig flow test as required during the startup sequence from its first refueling outage. Initial alignment requires opening the bypass valve (HV2F100) around the main steam inboard supply valve (HV2F002) to allow warmup and pressure equalization in the HPCI steam supply line. During this evolution, a walkdown of the system was being

performed when an operator observed some steam in the RHR Division I Pump Room. Upon investigation, the operator discovered water spraying down onto the floor from a drain line off of the HPCI steam line. HPCI was immediately isolated, Health Physics notified and two in-series drain valves (2F134A and 2F135A) on the line to the A RHR heat exchanger which had been left open were closed. Approximately 750 gallons of water spilled into the RHR Pump Room. Decontamination efforts proceeded rapidly and no personnel were contaminated.

The licensee determined that the 134A and 135A were left open because they were not listed on either of the divisional check off lists (COLs) but were on a common COL due to their location in the common steam supply header. Although the common COL had been performed on September 27, it is believed that the two drain valves had been left open following work which had been performed on two pressure control valves in the steam supply line. Thus, when the lineups for the individual divisions were performed, the 134A and 135A valve positions were not verified.

To prevent a recurrence of this event, the licensee will now required that, in addition to the individual division COLs, common COLs always be performed whenever work involves an individual division.

3.7 Waterhammers in Unit 2 RHR and Feedwater Systems

At 10:00 a.m. on October 24, while in reactor startup following Unit 2's first refueling outage a waterhammer occurred in the 'B' loop of the RHR System. While performing general operating procedure GO-200-002, Plant Startup and Heatup, Attachment G (RHR and CS Testable Check Valves Closed Verification), it was discovered that either the HV-249-F050B (RHR Loop B Testable Check Valve) or the HV-249-F122B (Testable Check Equalizer Valve) was leaking by its seat. This determination was made by observing that the 'B' Loop RHR pressure increased from the keepfill pressure of 150 psig to the reactor system pressure of 300 psig when the RHR injection outboard isolation valve (HV-249-F015B) was opened.

In an attempt to get the valve to seat, a decision was made to increase the differential pressure across the check valve by removing and isolating the keepfill system, decreasing the pressure on the RHR 'B' Loop to approximately 30 psig and opening 2F015B. It was at this time a water hammer occurred and system pressure increased to approximately 170 psig.

A plant operator was directed to walkdown the system and the 2F105B valve was closed. Plant Engineering was contacted to perform a walkdown of the affected piping. During the walkdown pipe hanger GBB-215-H15 was observed to be pulled from the wall. Repairs were initiated immediately to the RHR Hanger. Also, the licensee repaired HV-249-F122B to correct the seat leakage problem.

The licensee believes that hot water in the pipe may have flashed to steam when the pressure was reduced, and then the pipe voided as the steam condensed. When the injection valve was then opened, the water hammer resulted. The licensee's Nuclear Safety Assessment Group is performing a detailed review of this event to establish its root causes. Nondestructive examinations were made of the effects on RHR piping welds and pipe supports, with no other damage identified.

The inspector noted that, although GO-200-002, Attachment G does not provide specific direction for the method employed in attempting to seat F050B, Administrative Procedure AD-QA-300, Conduct of Operations, does allow flexibility to the operators to perform simple, routine tasks without the use of procedures. The licensee is reviewing the need for a test procedure to cover this activity.

On October 24, a manual scram was initiated to perform CRD scram time testing. To aid in cooldown to Condition 4, and in accordance with OP-245-001 (Reactor Feed Pump and Reactor Feed Pump Lube Oil System), the licensee decided to admit steam to the 'B' Reactor Feed Pump (RFP) turbine. Due to an interlock which prevents opening the steam admission valves to the RFP turbine without having the RFP suction valve open, it was necessary to first open the 'B' RFP suction valve. In accordance with OP-245-001, the 'B' RFP suction bypass valve was opened prior to opening the suction valve to allow pressure equalization. As soon as the operator saw pressure begin to increase he opened the 'B' RFP suction valve and a waterhammer occurred which damaged 3 hangers and an anchor. Technical staff and Plant Engineering were notified and repairs initiated immediately. Insulation was removed from piping around the feedwater pump and welds examined for damage.

The licensee has noted on previous startups that the RFPs do not remain pressurized when the bypass valve is opened due to valve leakage and this was currently being investigated by the technical staff. It is possible that the 10" minimum flow valve to the hotwell was leaking and the 2" bypass valve could not overcome the pressure loss. A work authorization is open for work on the 10" minimum flow valve during an upcoming outage. The 'B' RFP was subsequently started two times during the startup, but the problem did not reappear. In order to prevent a recurrence, a procedure change approval form (PCAF) to OP-245-001 has been initiated to ensure that the system is filled, vented and pressurized by both local and remote indication prior to opening the suction valve.

The licensee is incorporating these waterhammer events into the operator training program in order to increase operator awareness of the potential for waterhammers and to decrease the likelihood of a recurrence.

## 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

*86-032, Entry into LCO 3.0.3 to Perform 4KV ESS Bus Degraded Voltage Relay Surveillance.

86-033, Entry Into LCO 3.0.3 to Repair Control Structure Door.

**86-034, Hydrogen/Oxygen Analyzer Inoperable Due to Faulty Amplifier Board Replacement.

**86-035, Technical Specification Action Statement Not Met Following Diesel Generator Failure.

*86-036, Entry into LCO 3.0.3 to Perform 4Kv ESS Bus Degraded Voltage Relay Surveillances.

Unit 2

86-013, Intermediate Range Monitor Spikes During Refueling Cause Scram

86-014, Sampling of RHRSW Effluent Not Performed Due to Communication Deficiencies

*86-015, Containment Isolation Valve Closes Twice Due to Spurious High Flow Signal

86-016, Valve Mispositioning Due to Defective Procedure

86-017, Reactor Water Cleanup System Isolation on High System Flow

*Previously discussed in Inspection Report 50-387/86-18; 50-388/86-19
**Further discussed in Detail 4.2.

## 4.2 Onsite Followup of Licensee Event Reports

For those LERs selected for onsite followup (denoted by asterisks in Detail 4.1), the inspector verified that the reporting requirements of 10 CFR 50.73 had been met, that appropriate corrective action had been taken, that the event was adequately reviewed by the licensee, and that continued operation of the facility was conducted in accordance with Technical Specification limits. The following findings relate to the LERs reviewed on site:

### 4.2.1 LER 86-034: 'A' Drywell Hydrogen Analyzer Channel Inoperable Due To Amplifier Board Replacement Having Soldered Wire Connector Instead of Resistor (Unit 1)

On September 25, 1986 with Unit 1 operating at 80% power, the licensee observed during maintenance of the 'A' Drywell Oxygen/Hydrogen Analyzer that the high range mode of the hydrogen channel was continuously operating although the low range mode was selected. For the Somsip hydrogen monitor system, a common detector is used to drive both the low range (0-10%) and high range (0-30%) indications. The indications are displayed on a common dual scale indicator in the control room.

The event occurred when an amplifier board was replaced in the analyzer on June 26, 1986. A vendor installed wire connector on the amplifier board caused the amplifier to continuously operate in the hydrogen high range regardless of the selector switch position. The wire connector was a temporary installation in place of a resistor. The resistor to be installed is plant specific, depending upon the length of field run cable required for powering the analyzer. These analyzers are Comsip Inc.-Delphi Systems Division K-IV containment hydrogen monitors. The information contained in Comsip's Instruction, Operation and Maintenance Manual (IOM) did not state that the wire connector was installed on all replacement amplifier boards and needed to be replaced with the properly valued resistor. Therefore, when the original amplifier board was replaced in June, the wire connector was not removed and replaced with an appropriate resistor. Consequently, the low hydrogen range on the 'A' Drywell Oxygen/Hydrogen Analyzer was inoperable for 92 days until September 25, 1986, when corrective action was taken restoring it to operable status. During this period, the operators would have likely misread the control room indicator and, in the event of an accident, would have underestimated drywell hydrogen concentration.

Technical Specification 3.3.7.5 requires two operable hydrogen monitoring channels. The licensee performed a review of LCO and operator logs for the period from June 26 through September 25 and found that Unit 1 was in Condition 1 or 2 for 84 days and

that the 'B' Hydrogen Analyzer was operable during the entire time except for a 28 hour period on August 12 and 13 when repairs were made due to low cell flow. Therefore, the licensee considered that Unit 1 operated in a condition prohibited by the plant's Technical Specifications as a result of not discovering and repairing of the 'A' Drywell Hydrogen Analyzer.

Licensee corrective action included removing the wire connector from the amplifier board, installing the proper resistor in its place and observing satisfactory operation during a functional test of the range selection using span gas for a known hydrogen concentration. Action to prevent recurrence included tagging the hydrogen amplifier boards in stock to assure that the proper resistor will be installed on the amplifier boards in place of the wire connector prior to use. In addition, the vendor IOM will be revised to reflect that replacement amplifier boards have a soldered wire connector installed which must be removed and replaced with the proper resistor prior to installation in the plant.

The inspector reviewed all completed SO-100-002 (monthly Accident Monitoring Instrumentation Channel Checks) and S1-173-306 (Quarterly Channel Calibration of Hydrogen and Oxygen Analyzer AIT-15745 A&B and AIT-1574G A&B) surveillances performed during the period from June 1986 through September 1986 in an effort to determine if any of these should have alerted the licensee to the fact that the hydrogen analyzer was not operable. The monthly surveillance is a visual comparison of readings between the two analyzers and with hydrogen concentration reading on the average between .1 and .2 percent, not enough difference existed on the two scales (10% and 30%) to alert the operator of a problem. The quarterly surveillance uses a span gas concentration of 30% to calibrate the hydrogen concentration which requires placing the hydrogen monitor on the 0 to 30% scale. This test also would not alert the operator. Thus, neither surveillance procedure would have readily identified a problem with the hydrogen analyzer.

The inspector concluded that this matter constituted a licensee identified violation which meets the criteria of 10 CFR 2 Appendix C.

4.2.2 <u>LER 86-035: Technical Specification Action Statement Not Met Following Diesel Generator Failure (Unit 1)</u>

On October 3, 1986 the A and C diesel generators (D/G) were automatically started during performance of surveillance procedure SE-224-107, Division I D/G Auto Initiation Upon Loss of Offsite Power with a LOCA. The last portion of the test

involved transferring the emergency loads to offsite power and returning the D/G's to a standby status. At approximately 5:50 a.m., it was discovered that the A D/G frequency could not be varied to match offsite power preventing the transfer of emergency loads to offsite power.

Investigation revealed the problem to be a stripped lug in the speed control circuit. The stripped lug interrupted control power to the D/G manual speed control circuitry. During troubleshooting, temporary jumper was installed to restore manual speed control and the loads were successfully transferred at 7:44 a.m. The D/G was shutdown five minutes later, and the test was completed.

The temporary jumper was later removed by Maintenance technicians without Operations awareness. Operations later became aware of the jumper removal based on a discussion between the shift operators and Maintenance at 1:34 p.m. and immediately declared the D/G inoperable and entered the appropriate LCO. Operations had initially incorrectly assumed that the A D/G was operable since it had operated per design. However, the ability to synchronize and transfer emergency loads to offsite power is a Technical Specification requirement and an LCO should have been entered at 5:50 a.m.

Throughout the event, the A D/G was capable of automatically starting and energizing its emergency buses. The D/G frequency would have been maintained within limits automatically.

The stripped terminal log was repaired and the D/G was tested and declared operable at 2:00 a.m. on October 4, 1986. To prevent recurrence, the licensee will review the event with licensed Operations personnel.

4.2.3 <u>LER 86-015: Containment Isolation Valve Closes Twice Due To a Spurious High Flow Signal</u>

On October 12, 1986, while Unit 2 was shutdown in Condition 4, control room operators attempted to swap the 'D' and the 'B' Residual Heat Removal (RHR) pumps for shutdown cooling. With the 'D' pump running, the 'B' pump was started at 11:35 a.m. Following the start of the 'B' pump the running 'D' pump was shutdown. At approximately the same time, the outboard isolation valve (F008) on the suction side of the RHR pumps closed, causing the 'B' RHR pump to trip. Operations personnel reset the logic and then reopened the F008 valve. The opening of the F008 valve produced a waterhammer and caused the F008 to re-isolate. Following a walkdown of the piping (no obvious damage was noted) the RHR loop was filled and vented at 1:00 p.m. At 1:26 p.m. the 'B' RHR pump was successfully placed in service.

The cause of the automatic isolation could not be determined. Of the five signals which automatically cause an isolation, four are annunciated in the control room, and no alarms were received. The remaining isolation is RHR shutdown cooling high flow. The licensee determined that the probable cause was a pressure perturbation in the system during the pump swap which caused a spurious high flow signal.

The waterhammer, which followed the opening of the F008 valve, was due to the partial draindown of the system. The draindown resulted through a pathway to the condenser. This pathway was present to control reactor water level while the RHR system was in service. Following the 'B' RHR pump trip the control room operators failed to isolate the letdown path to the condenser and to fill and vent the system piping prior to reopening the F008.

The closure of the F008 valve resulted in the loss of shutdown cooling via the RHR system. As a result, Limiting Condition for Operation (LCO) 3.4.9.2 was entered. An alternate method for decay heat removal was maintained using the Control Rod Drive Cooling and Reactor Water Cleanup systems. Reactor coolant temperature rose from approximately 110 degrees F to 141 degrees F. Approximately thirty minutes after the 'B' RHR pump was placed back into service, reactor coolant temperature was restored to 110 degrees F. The licensee exited LCO 3.4.9.2 at 11:30 p.m.

To prevent recurrence, Operations personnel will review this event and the proper steps to place an RHR pump back into service following a pump trip. In addition, two subsequent waterhammer events are to be covered during the review (See Detail 3.7)

The licensee plans to submit an update to this LER by January 1, 1987 to include the possible effects, if any, if this event occurred during the emergency initiation of LPCI.

4.3 Review of Periodic and Special Reports

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

The following periodic and special reports were reviewed:

-- Monthly Operating Report - October 1986, dated November 14, 1986.

-- Special Report - 'C' Diesel Generator Non-Valid Failure, dated October 28, 1986.

-- Special Report - 'C' Diesel Generator Non-Valid Failure, dated October 30, 1986.

-- Special Report - 'B' Diesel Generator Non-Valid Failure, dated October 27, 1986.

-- Special Report - 'A' Diesel Generator Non-Valid Failure, dated November 26, 1986.

The above reports were found acceptable.

## 5.0 Monthly Surveillance and Maintenance Observations

### 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 tagouts 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:

-- TP-252-012, HPCI Pump Performance Verification, performed on November 7, 1986.

-- SO-231-001, Rod Worth Minimizer Operability Demonstration, performed on October 22, 1986.

-- SR-200-003, Shutdown Margin Demonstration, performed on October 22, 1986.

-- SO-256-005, Rod Sequence Control System Self-Test, performed on October 22, 1986.

-- SI-072-201, Monthly Functional Test of Offgas Hydrogen Analyzers, performed on November 14, 1986.

-- IC-70-001, Calibration of Fire Detection Panels, performed on November 24, 1986.

-- TP-250-006, RCIC Pump Performance Verification, performed on November 20, 1986

No unacceptable conditions were identified.

5.2 Maintenance Activities

The inspector observed portions of selected maintenance activities to determine that the work was conducted in accordance with approved procedures, regulatory guides, Technical Specifications, and industry codes or standards. The following items were considered during this review: Limiting Conditions for Operation were met while components or systems were removed from service; required administrative approvals were obtained prior to initiating the work; activities were accomplished using approved procedures and QC hold points were established where required; functional testing was performed prior to declaring the particular component operable; activities were accomplished by qualified personnel; radiological controls were implemented; fire protection controls were implemented; and the equipment was verified to be properly returned to service.

These observations included:

-- Quarterly inspection of Standby Gas Treatment System fan bearings, oil change, lubrication of damper bushings, and alignment and tensioning of fan belts, performed on November 24, 1986.

-- Modifications to Standby Gas Treatment System Temperature Instrumentation performed on November 24, 1986.

-- Residual Heat Removal System 52 A valve repairs (WA-V64912) performed on November 14, 1986.

No unacceptable conditions were identified.

5.3 Residual Heat Removal Service Water (RHRSW) Pumps

As a result of the failure of the similarly designed Emergency Service Water (ESW) Pumps in May, Unit 1 RHRSW Pumps 1A and 1B were inspected and overhauled in June 1986 (See Inspection Report 50-387/86-11; 50-388/86-11). During the Quarterly RHRSW System Flow Verification Surveillance Test on Unit 1 (50-116-003) following pump

overhaul, a decrease in both pumps discharge and differential pressures (dp) were observed. The licensee determined that the drop in pressure was caused by replacement of the pump impeller lines for the first stage which resulted in increased second stage clearances. This allowed leakage back through the second state resulting in reduced discharge pressure at the same pump capacity. In an attempt to obtain adequate pump pressures, 50-116-003 was re-performed on June 13, with flow throttled to the minimum acceptable of 8500 gpm resulting in dps of 79 and 75 psid for pumps 1A and 1B, respectively. Based on this data, an engineering evaluation confirmed operability, satisfactory flow, and dp for service and conformance with safety and FSAR considerations.

During the performance of 50-216-003 (Unit 2) on September 25, 26 and 27, RHRSW Pump 2B recorded dps of 60, 61, and 63 psid respectively at 9000 gpms; these data fell below the allowable minimum of 70 psid.

The data was obtained during a post-maintenance test, following partial overhaul of Unit 2 Pump 2B, similar to that performed on both Unit 1 pumps. A technical evaluation performed on this pump reached the same conclusion as for the Unit 1 pumps.

FSAR Section 9.2 states that the RHRSW pumps are rated at 9000 gpm each for a total of 18,000 gpm per loop, since Unit 1 and Unit 2 use a common header for each loop. Assuming a single failure takes out one loop of ESW and RHRSW, one loop remains intact which provides the required 9000 gpm for the LOCA unit, leaving 9000 gpm available for the safe shutdown unit.

Due to RHRSW pump degradation, 9000 gpm is not available for the safe shutdown unit. Therefore, another test was performed to analyze the effects of reduced loop flow based on that flow which was obtainable. This test ran the RHRSW system in several configurations: no throttling at the RHR Heat Exchangers throttling on Unit 1 to attain 9000 gpm on Unit 2 and throttling on Unit 2 to attain 9000 gpm on Unit 1. Since it is assumed that the 9000 gpm flow is provided to the unit with the LOCA, all design parameters are being met in that unit and no re-analysis is required for the LOCA. The licensee's analysis shows that the safe shutdown unit receiving only 7200 gpm affects spray pond performance, suppression pool temperature control and the rate at which the reactor can be brought to cold shutdown. The pond model has been run with the reduced RHRSW flow and its effects, i.e. decreased thermal efficiency, lower total flow, and lower RHR Heat Exchanger effectiveness. The result is that the peak pond temperature does not exceed 95°F which is the acceptance criterion for the minimum heat transfer case. Water loss is reduced since there is lower RHRSW flow. Thus spray pond performance was found acceptable. The suppression pool temperature was found not to exceed design requirements and the reactor could be brought to cold shutdown within the time requirements specified in the Technical Specifications.

Since the above analysis assumes no further degradation in pump performance, the surveillance frequency on Pump 2P506B has been increased to monthly.

Additionally, the licensee is evaluating the purchase of a new complete bowl assembly, which includes both the 1st and 2nd stage impellers and housing to replace the 2P506B assembly. Plus, additional parts are being ordered to overhaul the old bowl assembly.

This item will remain unresolved pending further review of the licensee's test and analysis results. (387/86-24-03; 388/86-26-01).

## 6.0 Unit 2 Refueling Outage Activities

### 6.1 Containment Instrument Gas Header Debris

During the Unit 2 first refueling outage, testing was performed on the Containment Instrument Gas System (CIG) but difficulties were encountered due to malfunctioning pressure control valve PCV-22643 and relief valve PSV-22643. The inspection of the CIG 'A' header was performed and it was discovered that it contained dirt and debris. The malfunctioning valves were also found with excessive debris in their internals. The licensee performed an air purge of the 'A' CIG 150/2000 psig header per test procedure TP-225-012 in order to remove the debris and reviewed the possibility that the same problem may exist in the 'B' CIG header. A pressure drop test performed on the 'B' header demonstrated that the nitrogen bottles can maintain 150 psig on the CIG accumulator for the ADS main relief valves. This test assures the PCV and PSV on the 'B' header are operating properly. In addition, inspection of the 'B' header noted that some debris exited, but lesser quantity was found compared to the 'A' header. No similar problems with the PSV and PCV malfunctioning have been experienced.

The majority of debris in both headers was found in the 2000 psig header section of piping. An analysis was performed by Chemistry to determine its composition in an attempt to determine the source of the debris. Although the source could not be positively determined it is probable that it did not come from the nitrogen bottles since the debris would have been expected to contain larger size particles. The solenoid isolation valves for the nitrogen bottles and the GIC swap on containment isolation, loss of power, or low pressure signals, isolating the CIG compressors and using the nitrogen bottles as the supply to the ADS valves. Since the headers are normally stagnant with minimal air movement, it is not expected that the debris could have distributed to locations where it could cause a malfunction of the ADS valves. The pressure change during transfer to the nitrogen bottles is minimal and air flow during operation of the ADS valves is only 7SCFH.

Nuclear Plant Engineering is currently evaluating the system design in both units for potential improvements as a result of the identified debris along with recurring leakage problems associated with this system. The inspector had no further questions.

## 6.2 Primary Containment Integrity

### 6.2.1 Drywell Equipment Hatches

On October 1, 1986, during the course of installing the Unit 2 drywell equipment access hatch (X-1), a Maintenance engineer discovered that the Unit 1 drywell equipment access hatch fastening bolts had not been preloaded to the values specified by the manufacturer. During the re-installation of the Unit 2 door at the end of the first refueling outage on October 1, the foreman in charge of the job noted that the work plan did not give specific instructions for tightening the thirty-two swing-bolts on the door. The work plan (WA V63189) stated to reinstall the hatch using vendor Instruction and Operational Manual (IOM) 174 as a guide. The IOM specified a bolt preload of 81.7 kips. The foreman contacted a Maintenance engineer to determine the proper torque to be applied, since he was not familiar with the necessary conversion. The engineer reviewed the previous work history to determine the proper torque and discovered that the two previous work orders used to reinstall the Unit 1 hatch did not specify the torque to be applied. Recognizing that if the equipment door bolts had not been properly torqued, the integrity of the primary containment was in doubt, the engineer prepared NCR 86-0722 to investigate this problem.

Work authorization S65509 was written to check the 'breakaway torque' of one of Unit 1 equipment door bolts. It was found to take between 100 and 200 foot-pounds of torque to move the nut in the tightened direction. The required torque was determined to be 1900-2000 foot-pounds. Based on this information, LCO 3.6.1.1 was entered at 12:15 a.m. on October 2. The one hour allowed to restore containment integrity expired at 1:15 a.m. and in accordance with Technical Specifications a controlled shutdown was commenced. The necessary ENS notification was made at 2:15 a.m.

The event was caused by errors made in the work planning process during previous installations of the door. The Unit 1 equipment access hatch was inadvertently left under-torqued after completion of the Unit 1 first refueling outage in May 1985, and was reinstalled incorrectly again after the second refueling outage in April 1986. Therefore, Unit 1 operated for the entire second fuel cycle of approximately ten operating months and for the first four months of the third operating cycle with the

equipment access hatch bolts under-torqued. In all cases reviewed, the LLRTs performed after door installation were successful. In addition, the ILRTs were also within acceptance criteria.

Inspector review of the previous work history documentation verified that the equipment access doors were properly torqued for both units prior to initial startup. During the subsequent outages, the work plans did not specify a torque value. The licensee determined that following the first refueling outage, the work planner for the task did not understand the significance of the preload requirement, and that it was assumed that successful completion of the LLRT was adequate to verify containment integrity. The inadequacy in the work plan was also not detected during the work package review process. Following the second refueling outage, the work plan was prepared by the same individual. During the review process, Quality Control questioned the absence of torqueing requirements, but a maintenance engineer re-stated that there were no torqueing requirements. During performance of the task, the maintenance technicians requested further guidance on torqueing, and the plan was revised to show a tightening sequence, but no torque values were specified.

In summary, the work plans used on the previous door installations were not adequate for this task. The work plans were not thoroughly researched in spite of the fact that sufficient information was available in the IOM and associated drawings to adequately install the hatches. There were no specific maintenance procedures in place for this evolution.

As part of its corrective action, the licensee plans to develop a detailed procedure covering containment penetration installations prior to the next scheduled outage.

The licensee also reviewed the controls of the other containment hatches to determine their status. The drywell head has a specific maintenance procedure, MT-062-002, which clearly specifies the bolt tensioning requirements. The personnel access doors were found not to have been disturbed since construction completion. The CRD removal and suppression pool hatches are designed differently from the equipment and personnel access doors, and thus have different requirements. IOM 174 specifies that the bolts be hand tightened until a clearance of 1/16 inch exists between the faces or until a leakage test can be passed. No bolt tension is specified. Problems were later identified with the CRD and suppression pool hatches (See Detail 6.2.2).

As part of the investigation, calculations were performed by Nuclear Plant Engineering (NPE)-Civil which showed that, with the bolts torqued to their as-found condition, sufficient strength existed at all times to resist the maximum design accident loads and that the gaskets would have maintained the necessary seal against accident pressures. In addition, calculation EQ-C-TAG-050 showed that the shear stresses placed on the gasket under worst possible combinations of loads were less than the tearing strength of the gasket. NPE also showed that the door could not have moved under normal operating loads including the safe shutdown earthquake. These calculations were forwarded to a specialist inspector in NRC Region I for further review.

6.2.2 Suppression Pool and CRD Removal Hatches

On October 24, 1986, at approximately 9:00 p.m. an engineer was inspecting RHR piping in the Unit 2 reactor building following a waterhammer event (See Detail 3.7), when he noticed that only 5 of the 36 nuts on the Unit 2 'A' suppression pool hatch (X-200A) were properly hand tightened. The hatch had been previously installed on October 4 and a local leak rate test had been successfully performed.

Upon discovery, the maintenance department was informed of the problem, but the hatch was thought to be satisfactory, since the IOM only specified hand tightening. On October 25, a maintenance foreman personally hand-tightened all of the loose bolts, without a WA, and did not inform Operations. He did not consider the impact on the current LLRT. The problem was identified during a Unit 2 startup with the Unit at 1 percent power and 215 ° F. An LCO was entered due to the indeterminate status of the primary containment, and an ENS notification was made at 5:20 p.m. on October 27.

After further review of the event by management, the startup was halted and the licensee decided to inspect the suppression pool and CRD hatches on both units. The Unit 2 CRD removal hatch was found with 18 of 32 nuts loose (less than 1/6 of a turn) and two loose nuts were found on the Unit 1 CRD removal hatch. LCO's were entered for these hatches and the appropriate ENS notifications were made. Local leak rate tests were conducted in the 'as found' condition on all of the hatches with satisfactory results.

NPE calculations were performed to show that the five bolts on the Unit 2 suppression pool hatch had sufficient strength to hold the hatch in place under design accident conditions. Calculations were also performed for all of the remaining hatches which provided reasonable confidence that the gasket would have maintained the necessary seal. All of the 'as found' and post-tightening LLRT's were satisfactory.

The cause of the loose nuts appears to be the result of the method used in securing the hatches and the type of seal employed. The cover plate and the flange face do not make metal-to-metal contact, but retain an approximately one-sixteenth inch gap to prevent damage to the elastomer gaskets. The nuts were hand tightened in a sequence which allowed the nuts initially tightened to become loose as the remaining nuts were tightened, drawing the cover to within 1/16 inch of the flange. The initially tightened nuts were then not verified to be hand tight as long as the LLRT passed. The IOM states that the bolts are to be hand tightened, sequentially and uniformly 'until the gap between the cover and the opening flange is approximately 1/16 inch or as required to obtain a leak tight closure.' In addition, there is a caution against excessive tightening which may damage the gaskets.

A work plan to properly tighten the hatches was developed and approved by PORC. The procedure requires verifying a torque of 10 foot-pounds on each nut. The Unit 2 hatches were tightened and retested by an LLRT prior to resuming the plant startup. The Unit 1 hatches were also satisfactorily retested.

6.2.3 Summary

Although it appears that primary containment integrity was not violated during these two events, it appears that problems existed in the controls of these evolutions.

The adequacy of controls on containment penetrations remains unresolved pending NRC review of the licensee's corrective actions. (388/86-26-02).

## 7.0 IE Bulletin and Information Notice Followup

### 7.1 IE Compliance Bulletin No. 86-03: Potential Failure of Multiple ECCS Pumps Due to Single Failure of Air-Operated Valve in Minimum Flow Recirculation Line

IE Compliance Bulletin No. 86-03, "Potential Failure of Multiple ECCS Pumps Due to Single Failure of Air-Operated Valve in Minimum Flow Recirculation Line", was issued on October 8, 1986 to inform licensees of single failures of minimum flow recirculation lines containing air-operated isolation valves which could result in a common-cause failure of all emergency core cooling system pumps in a system, and to request certain actions by licensees following review of their system configuration. The Bulletin also stated that actions required of BWR plants in response to IE Compliance Bulletin No. 86-01 need not be repeated in responding to the Bulletin.

The licensee responded to the Bulletin on October 31, 1986 (PLA-2745) and stated that it had verified that the condition did not exist at Susquehanna, since totally independent and redundant minimum flow recirculation lines are utilized for each train in all of the two train ECCS systems.

Inspector review of the licensee's system configuration was previously performed during followup to IE Bulletin 86-01 and is documented in Inspection Report 50-387/86-11; 50-388/86-11.

No unacceptable conditions were identified.

8.0 Containment Radiation Monitor Pump Leakage

On October 3, 1986 the licensee reported that an unmeasurable leakage rate (greater than 100 liters/minute) was identified from a test boundary which included the Unit 2 containment air monitoring, post-accident sampling and Hydrogen/Oxygen analyzer systems, when pressurized with air to a post-accident pressure of 35 psig. The leakage was identified during the performance of Unit 2 surveillance test SE-273-400, PASS/CAM System Leakage Quantification Test, which is required by Technical Specification 6.8.4. Further licensee investigation determined the leakage source to be vent holes located on each containment radiation monitor (CRM) sample pump. The remainder of the system boundary, with the pumps isolated, was found to have a leakage rate of less than 15 liters/minute (14,690 sccm), which when added to the current LLRT total leakage, was less than 0.6La. Similar condition were found on Unit 1 on October 10, 1986.

Technical Specification 6.8.4, for both units, states that a program is to be established, implemented, and maintained to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems to be monitored in the program include post-accident sampling and containment air monitoring. The program is required to include preventive maintenance, periodic visual inspections, and integrated leak tests for each system at refueling cycle intervals.

Administrative Procedure AD-QA-481, System Leakage Quantification Program, describes the administrative controls necessary for implementation of the leakage quantification program as required by Technical Specification 6.8.4 and as discussed in FSAR Section 18.1.69. The procedure specifies the surveillance procedures to be performed, on a refueling cycle frequency, to determine the system leak rates. The acceptance criteria for the total leakage from the fluid systems is 5 GPM, since FSAR Section 15.6.5 states that it was assumed in the accident analysis that 5 GPM of liquid leakage would contribute to the radioactive release to the reactor building. The FSAR and the associated TMI Action Plan Item, III.D.1.1.1, do not specify a numerical acceptance criterion for the gaseous systems. FSAR Section 18.1.69 states that the acceptance criteria is 'zero leakage' as determined by a liquid soap test of the mechanical joints under normal operating conditions.

Unit 2 surveillance test SE-273-400 performs the leakage quantification of the gaseous portion of the PASS and containment air monitors outside containment. In previous versions of the test, the system was operated under normal conditions and each mechanical joint was checked for visible leakage with liquid soap. Technical Staff engineers, in the process of rewriting the test procedure, questioned the adequacy of this method since the suction portion of the system normally operates under a vacuum and a soap test would be inaappropriate. In addition, much of the piping is heat traced and insulated, making it difficult to inspect the system. Although the CRMs are not required to operate post-accident, they share a common containment penetration with the Hydrogen/Oxygen analyzers and PASS. This penetration is reopened by the control room operators 10 minutes after a LOCA. Once the isolation valves are reopened, the entire system, including the CRMs, essentially becomes an extension of primary containment. The licensee decided to perform an LLRT-type test at post-accident pressures to determine the actual leakage rate from the system. The licensee also elected to add additional conservatism by adding the PASS/CAM pneumatic test results to the combined LLRT results to ensure total containment leakage is less than 0.6La (190,745 sccm). The licensee is currently developing a specific acceptance criterion for this testing.

The licensee determined that the positive-displacement Roots-Dresser sampling pumps, as originally supplied by Nuclear Measurements Corporation (NMC), had been sealed to achieve adequate leak tightness for this specific application. However, the vendor manual did not adequately describe the pump seals. The licensee purchased replacement pumps directly from Roots-Dresser. These pumps which were not sealed. This was not identified as a deficiency since the vendor manual did not describe the seals. If the replacement pumps had been ordered from NMS using the NMC part number, a sealed pump would have been supplied.

A review of the maintenance history of the blowers performed by Maintenance Engineering revealed an initial history of poor pump performance and extremely short pump life. Maintenance, in an attempt to extend the life of the blowers, performed significant investigation and rework activities, which included removing blower casing vent plugs to allow for proper ventilation in accordance with pump vendor instructions and existing NMS documentation. The rework resulted in longer life and significantly reduced maintenance.

Licensee review of vendor information determined that the vendor had delivered a panel which had passed a pressure/leak test at accident pressures. NMC purchased the pumps from Roots-Dresser and reworked the seals and vents to ensure a leak-tight configuration. The vendor informed the licensee that this information had been available, but had not been provided. Discussion of the sealing requirements was not provided in any design document or instruction manual received by the licensee. NMC has now provided the licensee with the necessary sealing details. With this new information, non-conformance reports were generated on the existing pumps since the seals are not installed.

The licensee's immediate corrective action on October 7 consisted of changes to the system operating procedures and off-normal procedures to require manual isolation of the CRMs prior to reopening the sampling line isolation valves following an accident. A safety evaluation was prepared and approved by PORC which justified continued operation of both units under this condition. Additional interim corrective action on October 7 consisted of additional procedure changes which manually isolated the lower drywell supply line and both wetwell supply and return line globe valves and provided remote manual operator action after an accident to select the wetwell sample lines via the solenoid selection valves. Since the wetwell globe valves were manually isolated previously, all five sample valves on the CRM will be isolated, either by a globe valve or a solenoid valve. This eliminated the need for an operator to enter the reactor building. The licensee's action also included periodic leak testing of the solenoid valves. The initial valve leak checks were performed on October 17, 1986.

An additional concern identified was that the blowers could be pulling air from secondary containment through the open vent holes, and introducing it to the primary containment. The units have had problems with air leakage into the containment, requiring frequent nitrogen makeup to maintain the containments inerted. It now appears that the CRMs could be significant contributors to this problem.

The licensee is evaluating several alternatives for long term corrective action, which include installation of additional containment isolation valves, repiping the system to new penetrations, procuring and installing new leak tight blowers, or installing a completely new system. The old sample pump design is no longer being manufactured, and only the spares onsite are available. A suitable replacement is currently not commercially available.

The licensee performed a reportability evaluation to determine if the containment air sample pump leakage was reportable under 10 CFR Part 21. A previous review had found the deficiency not reportable under 10 CFR 50.72 and 10 CFR 50.73. The licensee concluded that a substantial safety hazard did not exist and was therefore not reportable. The conclusion was based on the assumption that increased leakage through the pump would not significantly increase the offsite dose. To verify this assumption an Engineering Work Request was issued, which has not yet been completed.

The inspector reviewed the operating and off-normal procedure changes implemented as part of the corrective action. Operating procedure OP-173(273)-002 was revised to perform a manual valve lineup of the CRM sample points to minimize system leakage following a LOCA. Currently, only one radiation monitor is in service sampling the drywell. The standby unit may be placed in operation for short periods of time under administrative controls. Off-Normal procedure ON-159-002, Containment Isolation, was also revised to direct the operators to isolate the CRM system prior to reopening the sample line penetrations to the PASS and Oxygen/Hydrogen monitors following an isolation.

The inspector reviewed the previous testing program and the results of completed tests to determine if there were prior indications of the leakage problem. Prior to May 1986, the gaseous systems were only tested by soap tests of the mechanical joints. In May 1986, during the process of changing the program responsibility from Operations to the Technical Staff, a special test procedure TP-176-003, was performed on the Unit 1 PASS system to assess a pressurization type test. The leakage rate of 3053 sccm was measured at 44 psig. The total system leakage test which identified the problem on Unit 2 is currently being written for Unit 1 and will be performed during the next refueling outage. A modified test was performed on Unit 1 following identification of the pump problem to verify the system integrity and adequacy of solenoid valve isolation.

During review of completed surveillance SO-200-018G, performed on the Unit 2 CRM in April 1984, a remark was included on the surveillance cover sheet by the test performer, that the suction piping was walked down for visible and audible leaks, but snoop was not utilized per the cognizant plant staff engineer due to the negative pressure of the system. Further review by the inspector could not determine what, if any, corrective action resulted from these comments, but it does indicate that the adequacy of the testing method had been previously questioned.

In summary, the licensee initially received leak-tight blowers in the CRM panels. However, the actual blower design/configuration with respect to sealing was not adequately defined by the vendor. The sealing methods employed by the vendor resulted in premature failure of the blowers. Maintenance reworked the blowers in accordance with existing controlled documentation. The rework yielded improved blower life and reduced maintenance, however, the leak-tight nature of the blower was degraded. The lack of clear documentation from NMC was also partially responsible for the problem. In addition, the previous system leakage tests performed in accordance with Technical Specifications were not sufficient to identify the problem.

Once the problem was identified and clearly defined, the licensee took prompt corrective action to place the CRMs in a configuration considered prudent for post-accident concerns. An action plan was implemented and long term solutions are being pursued, including a contingency for spare pump availability. The licensee will also have to revise the FSAR to accurately reflect the testing method to be utilized for the gaseous systems, since it currently specifies a soap test.

This item is unresolved pending completion of the licensee's corrective actions (388/86-26-03).

## 9.0 Employee Safety Concerns

On November 14, 1986, several employee concerns were received by NRC Region I concerning the licensee's Environmental Qualification program, and concerning problems with taking safety concerns to supervisors.

The concerns addressed several specific areas in the Environmental Qualification program and were reviewed by NRC during a scheduled Environmental Qualification Audit performed on November 17-21, 1986. The results of the audit are documented in Inspection Report 50-387/86-25; 50-388/86-28. In summary, the NRC team found no problems related to these concerns.

The remaining concerns were related to the ability of licensee employees to take safety concerns to their supervisors. Included in the information provided by the employee, was a questionnaire related to this topic, which was distributed to NPE personnel.

On October 2, 1986, NRC Region I issued a letter to the licensee discussing recent allegations which appeared to indicate an employee reluctance to take safety concerns to licensee supervisors. The licensee responded to the letter on November 11, 1986 (PLA-2751). The licensee stated that the Nuclear Department policy is one of openness about employee problems and concerns. There are a large number of mechanisms available to employees and contractors to make their concerns known, which are repeatedly emphasized through general employee training, bulletin board postings, reminders in staff meetings, and weekly site newsletters. The licensee plans to review this issue again, due to the recent employee concerns, and to reemphasize this responsibility with the supervisors. In addition, a direct communication to all department personnel is planned to reiterate the licensee policy toward employee concerns. A videotaped message from senior nuclear department management is also being developed for general employee training.

The inspector discussed the results of the questionnaire with the Manager of NPE and was provided with the results of the questionnaire. Although the questionnaire was not officially generated within the licensee's organization, the results were evaluated by licensee management to determine if corrective action may be required.

Of the questionnaires distributed, 42 were returned. Some of the questionnaires contained responses which could be viewed as negative, however none of the responses implied that valid safety concerns were not being adequately addressed. The majority of the negative comments concerned the increased work load incurred when safety-concerns were raised, and, the fact that the engineers were not encouraged to 'find' safety-concerns, but only to resolve already identified issues.

In response to several other initiatives, and the results of this questionnaire, the licensee is developing several correction action measures which include organizational and scheduling process changes. In addition, the employee concerns were recently discussed in a SRC meeting. Although not yet implemented, the proposed actions should improve the employee's ability to raise and resolve safety issues, although the current programs do appear adequate.

Based on inspector discussions with licensee employees and on review of the completed questionnaires, there does not appear to be a serious problem with the availability and use of the channels to pursue safety-concerns. Rather the principle concerns were with time availabile to resolve an identified issue. For example, for an individual who has his time fully budgeted weeks in advance, if he identifies a safety concern and is asked to resolve it, he still must meet his previous task assignments in addition to the new issue. This concern is being addressed by the licensee's corrective action program.

Review of the licensee's improved programs to resolve the employee's concerns will be performed in routine inspection activities.

## 10.0 Exit Meeting

On December 15, 1986, the inspector discussed the findings of this inspection with station management. Based on NRC Region I review of this report and discussions held with licensee representatives, it was determined that this report does not contain information subject to 10 CFR 2.790 restrictions.