U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-387/83-03
50-388/83-01

Docket No. 50-387 (CAT B) 50-388 (CAT A)

License No. NPF-14
CPPR-102 Priority -- Category --

Licensee: Pennsylvania Power & Light Company
2 North Ninth Street
Allentown, Pennsylvania 18101

Facility Name: Susquehanna Steam Electric Station

Inspection At: Salem Township, Pennsylvania

Inspection Conducted: January 12 - March 8, 1983

Inspectors: G. Rhoads 3/9/83 date

J. McCann 3/9/83 date

date

Approved by: Ralph R. Architzel for Ebe C. McCabe, Chief, Reactor Projects Section 2B, DPRP 3/14/83 date

Inspection Summary: January 12 - March 8, 1983 (Combined Reports 50-387/83-03, 50-388/83-01).

Routine resident inspection (159 hours Unit 1, 79 hours Unit 2) of: Preoperational test review; Startup test witnessing; Licensee event followup; Technical Specification Compliance; Open items and Plant status. Violations concerning the inoperability of the Standby Gas Treatment System are discussed in paragraph 9.

DETAILS

1. Persons Contacted

Pennsylvania Power and Light Company

R. Beckley, Resident NQA Engineer
S. Denson, Project Construction Manager
A. Dominiguez, Sr. Project Engineer
F. Eisenhuth, Sr. Compliance Engineer
R. Featenby, Assistant Project Director
J. Green, Supervisor, Operations Quality Assurance
H. Keiser, Superintendent of Plant
R. Matthews, Sr. Analyst - NQA
R. Sheranko, Startup & Test Field Engineer
D. Thompson, Assistant Superintendent of Plant

Bechtel Corporation

G. Bell, Project QA Engineer
E. Figard, ISG Supervisor
G. Gelinas, Project Field QC Engineer
A. Konjura, Lead Quality Assurance Engineer
T. Minor, Project Field Engineer
W. Mourer, Field Construction Manager

2. Licensee Action on NRC Findings

a. (Closed) Inspector Followup Item (388/82-14-01) Battery Test Load Bank Calibration.

The inspector reviewed Test Change Notice No. 025 to Preoperational Test P202.1B, Revision 1, which provides reference to Work Authorizations WA-U-23689 and U-23709 under which the load bank calibrations were performed. This provides a traceable calibration record.

b. (Closed) Bulletin 82-04 (387/82-BU-04; 388/82-BU-04) Deficiencies in Primary Containment Electrical Penetration Assemblies.

On January 3, 1983, the licensee reported that Bunker Ramo electrical penetrations have not been and are not planned to be used in safety-related systems. No further action is required by the bulletin.

c. (Closed) Construction Deficiency (388/81-00-15) Improper Orientation of Isolation Dampers in HVAC System.

The inspector reviewed P&ID No. 2176 to verify that steam flow direction information was provided. Two dampers were chosen to verify that they were installed in accordance with the P&ID and vendors orientation instructions; BDID 27675B and BDID 27652B. These dampers were observed to have the words "Steam-Flow" stenciled below the red arrow, and to be properly installed.

A Special Surveillance SSI-82-28 was also reviewed, and documents that the licensee's Construction Surveillance Group reviewed the marking and orientation of all Unit 2 isolation dampers.

3. Plant Tours

The inspector conducted periodic tours of accessible areas in the plant during normal and back-shift hours, including daily visits to the Unit 1 Control Room. During the control room visits the inspector verified operator awareness and response to unusual plant conditions and alarms, reviewed operating logs and data since the previous visit, and performed sampling checks for proper safety system alignment. During the plant tours the inspector observed housekeeping and cleanliness control, construction work in progress, testing, maintenance, in-plant storage and protection of equipment, security measures, and proper equipment line-up.

a. The Unit 2 suppression pool was inspected on February 9, to verify that conditions were acceptable for flooding. Specific areas verified included:

   -- Cleanliness and cleanliness controls.

   -- Access control.

   -- Completeness of the inorganic zinc liner coating.

   -- Leak-chase plugs installed.

   -- Temporary fittings and protective covers removed.

   -- Scaffolding, ladders, platforms removed to maximum extent possible.

   -- Strainers, fittings installed or identified on start-up work list.

   -- Work remaining to be done above the water line can be accomplished without adverse impact on pool cleanliness.

   -- General material condition.

   Findings:

   The floodable volume was clean and controls to maintain cleanliness were acceptable. No deficiencies were observed in the liner coating or leak-chase integrity. One temperature detector pipe was noted to be taped over the end. The tape was immediately removed by the startup engineer who accompanied the inspectors.

   Several "detail-600" type hangers which are installed on the containment instrument gas piping (JCD-215) were noted to have the same problems as those found in Unit 1 during NRC inspection 387/82-31. Several hangers had no gap between the ears or the nut in contact with the shoulder of the bolt connecting the ears. These problems were previously determined to invalidate the axial restraint feature of the clamps since sufficient friction between the pipe and clamp could not be proven.

The inspector discussed this apparent problem with the Bechtel Small Pipe Lead Design Engineer, who stated that the hangers had been evaluated and it was determined to use them "as-is". Justification for this decision was to neglect the friction effect of the clamp on the pipe and consider the pipe to be restrained in only two planes, but to consider the full friction effect to occur when analyzing the attachment of the hanger to the structure. Although this piping is not safety related, it has safety impact since its collapse could adversely impact safety systems. Components of this type are required to be analytically checked to confirm their integrity against collapse from the Safe Shutdown Earthquake. The inspector requested the stress analysis for this piping in order to verify that it takes no credit for axial restraint from the hangers and is still adequate. This item remains unresolved pending review of the stress analysis. (388/83-01-01)

The inspector also noted several minor material discrepancies such as small items on the cat-walk which were not removed during clean-up, a loose grounding wire guide on the Hydrogen Recombiner, and nuts and bolts left in the holes of hanger attachments which are not going to be used. The startup engineer who accompanied the inspector noted these items for correction.

The major work remaining in the wetwell is the installation of the down-comer vacuum breakers. This work can be accomplished without significant impact on the pool water quality.

b. On February 8 the inspector reviewed Operating Surveillance Procedure SO-00-006, Revision 3 to ascertain whether technical specification channel checks were being properly performed. Section 6.0 of the procedure defines what a channel check should be. The definition parallels their technical specification definition. The logs for the actual channel checks lists each instrument requiring a channel check and where it is located. The operator is required to state on the log whether the channel check was performed satisfactorily. Part of the channel check requirement is to include, where possible, comparison of the channel indication and/or status with other indications derived from independent instrument channels measuring the same parameter.

The inspector noted that some channel checks were performed in the control room while others were performed outside the control room. The inspector asked operators who performed the surveillance outside the control room and found that usually control room operators did the surveillances inside the control room, and Nuclear Plant Operators performed the checks outside the control room. The inspector asked how the comparison between instruments outside the control room and inside the control was being performed, since no parameters were being written down in the log, and different individuals were taking the reading. On February 17 this item was discussed with the Supervisor of Operations. This item is unresolved pending resolution of how comparison is being followed. (387/83-03-01)

4. Preoperational Test Procedure Review (Unit II)

The inspector reviewed Preoperational Tests P217.1A, "Instrument AC", and P257.1A, "Uninterruptable AC", to ensure that the test procedures were technically adequate, and that they were consistent with the Final Safety Analysis Report test committments, the Safety Evaluation Report, and the Unit 1 technical specifications. The inspector noted the test description for the Instrument AC switchboard differed from the FSAR in that a load test would not be performed. The inspector also reviewed the FSAR change request which was written to describe the planned test procedure. The licensee justifies deletion of the requirement to test the distribution panels under full load by noting that such testing is not consistent with other distribution panel tests, and that since the panel is identical to the one tested under full load during the Unit 1 program, qualification of the panel design has already been demonstrated. The inspector stated that the proposed FSAR change did not need to be reviewed by the NRC office of Nuclear Reactor Regulation (NRR) prior to running the test, but that if the NRR reviewer disagrees with the proposed change, a load test would have to be done. The inspector will verify that this FSAR change is approved prior to fuel load. (388/83-01-02)

The inspector had no comments on test P257.1A.

5. Plant Maintenance/Preventive Maintenance During Preoperational Testing

A review of the Startup Administrative Manual and the Administrative Procedures Manual was performed to verify that administrative controls have been established which include the following:

- Criteria for determining when maintenance procedures will be provided.
- Method for preparing maintenance procedures.
- Requirements for reviewing and approving maintenance procedures.
- Methods of determining when training of personnel in the use of maintenance procedures is required.
- A formal method to assure that appropriate approvals will be obtained prior to performing any maintenance activity.
- Inspection of maintenance work including final inspection of a completed task.
- Testing of structures, systems or components following maintenance to reestablish the validity of preoperational tests.
- Control of test and measurement equipment utilized in maintenance activities.

The procedures reviewed include the following:

Administrative Procedure Number	Title
AD-QA-500	Conduct of Maintenance
AD-QA-502	Work Authorization System
AD-00-504	Preventive Maintenance Program Prior to Fuel Load
AD-00-540	Preventive Maintenance System

Startup Administrative Procedure Number	Title
6.9	Test Equipment Control
6.10	Equipment Maintenance and Operations Control
6.13A	Control of Electrical Components Testing During Test Phase
6.13B	Control of Mechanical Component Testing During Test Phase

The inspector also reviewed computer records of maintenance performed and scheduled, and interviewed members of the new Unit 2 maintenance staff.

Findings:

A new, separate, Unit 2 maintenance organization has been established, but the responsibilities and function of this organization has not been incorporated into the Startup Administrative Manual. The licensee's representative stated that the procedures are being revised to reflect the current organization and would be issued by April 1, 1983. The inspector will review these procedures during a future inspection. (388/83-01-03)

The inspector noted that preventive maintenance requirements for turned over equipment had, for the most part, not been initiated. The large majority of equipment turnover occurred after September, 1982, and approximately 45% of the systems are turned over. The inspector discussed this issue with the Maintenance Supervisor, who stated that implementation of the routine storage-type preventive maintenance for Unit 2 equipment was intentionally delayed until completion of functional testing, and that because of the expected rapid transition to preoperational testing and startup, some systems would immediately enter the operations preventive maintenance program. The Maintenance Supervisor also stated that the functional tests which are performed when equipment is turned over far exceed the routine preventive maintenance, and therefore the delay in implementation is justified. The inspector reviewed the Work Authorization History computer printout for a random selection of plant systems which included Reactor Building Cooling Water, Primary Containment Instrument Gas, Residual Heat Removal, Core Spray, and Emergency Service Water Systems to verify that maintenance performed under the functional test requirements would satisfy the intent of preventive maintenance requirements. The work performed on components in these systems was generally in excess of routine preventive maintenance requirements. As an example, Work Authorization U-30029 documents the initial inspection of Residual Heat Removal Pump motor which involved inspection of upper and lower bearings, meggering of windings, checking clearances, inspection of the termination box, and an oil change. Additionally, the Work Authorizations establish cleaning and housekeeping requirements for restoration of the components. The inspector stated that although the program which is actually being followed to ensure that turned-over equipment is properly maintained appears to be adequate, it does not agree with the procedures, and that the procedures should be revised to formalize the current program. The Maintenance Supervisor stated that this would be done by April 1, 1983. These procedure changes will be reviewed in a subsequent inspection. (388/83-01-04)

6. Startup Testing

Generator Load Reject Test (ST27.2)

a. On February 12 and 13 the inspector witnessed the High Power Generator Load Reject Test. This test was initiated from test condition six (approximately 97% thermal power). The inspector noted the following during the test:

1. The auxiliary bus did not fast transfer to the startup bus upon initiation of the load reject. This caused the condensate pumps, circulation water pumps, and service water pumps to trip. The trip of the condensate pumps caused the reactor feedwater pumps to trip on low suction pressure. The loss of the reactor feedwater pumps caused vessel level to decrease until a level two signal initiated Reactor Core Isolation Cooling (RCIC), High Pressure Coolant Injection (HPCI) and shut the Main Steam Isolation Valves (MSIV's) which restored water level.

2. In total five actuations of steam relief valves occurred. At the initiation of the load reject three relief valves lifted and then shut. After approximately 21 seconds one relief lifted with indicated reactor pressure at approximately 1050 psig. Later in the recovery the operators manually opened one relief to reduce plant pressure.

3. Reactor building chill water to drywell ventilation cooling was interrupted during the test due to the loss of service water to the chill water system. The plant operators had difficulty restarting the chill water system even after restoring the service water system. Before cooling to the drywell could be restored the drywell average temperature reached 140°F, which was above the technical specification 3.6.1.7 limit of 135°F. The operators restored cooling to the drywell and temperatures were restored to normal. The drywell temperatures exceeded the technical specification limit for about 30 minutes.

b. On February 14 to 16 the General Electric Transient Analysis Recording System Charts were reviewed. The following additional items were identified:

1. Steam dome pressure went to approximately 880 psig before the main steam bypass valves shut (around 40 seconds into transient The Electric Hydraulic Control System steam setpoint was set at 920 psig which should have caused the bypass valves to shut at this pressure. On February 15 the licensee verified the setpoint of 920 psig was accurate.

2. The Reactor Core Isolation Coolant System initiated 40 seconds from start of transient with reactor water level as indicator on wide range level instrument of -28 inches. This is more conservative than technical specification of -38 inches.

3. The Main Steam Isolation Valves went shut 42 seconds into the transient.

On February 16 the licensee determined that due to the slow transfer of the auxiliary bus, and the subsequent MSIV isolation that the test should be rerun.

On March 4 the licensee reran the load reject test from approximately 98% thermal power. This test is described in NRC inspection report 387/82-05. No unacceptable conditions were noted.

7. In Office Review of Licensee Event Reports (LERs)

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

-- LER 82-073/03L-0, "B" Control Structure Chlorine Detector Was Inoperable

-- LER 82-074/03L-0, Sodium Pentaborate Concentration In The Standby Liquid Control Tank Was Not Within Allowable Specifications

-- LER 82-075/03L-0, Diesel Generator Experienced An Erroneous Trip Caused By a Jacket Water Cooler High Temperature Switch

*-- LER 82-076/03L-0, Reactor Recirculation Pump Motor Generator Set Tripped Which Shut Down Its Associated Recirculation Loop

-- LER 82-077/03L-0, One High Pressure Coolant Injection Steam Line Sensor Which Detects Line Breaks Was Found Above the Allowable Value

-- LER 82-078/03L-0, Jet Pumps 14 and 16 Were Not Indicating During Performance of Surveillance Testing

-- LER 82-079/03L-0, Reactor Coolant System Temperature Exceeded the 100°F/hr heatup rate limit

-- LER 82-080/03L-0, The Surveillance Required Per Technical Specification 4.2.2.a Was Not Performed Within The Allowable Time

-- LER 82-081/03L-0, Reactor Manual Control System Failed (Panel Indication). The RMCS Could Not Be Reset, Therefore, Control Rod Position Could Not Be Determined And They Were Declared Inoperable

-- LER 83-001/01T-0, Grab Samples Required To Comply With An Action Statement Were Not Taken In The Required Time Period

-- LER 83-002/01P-0, Failure To Perform The Monthly Channel Functional Test Of The Main Steam Line Isolation Valve Closure Position Switches

-- LER 83-003/03L-0, Reactor Building Heating Ventilation And Air Conditioning Zone III Instrumentation Indicated The Required Vacuum Was Not Maintained.

-- 83-004/03L-0, "C" Diesel Generator Experienced a Non-Valid Failure To Start During Performance of a Surveillance Test.

-- 83-005/03L-0, Unidentified Reactor Coolant System Leakage Exceeded 5 gpm.

-- 83-006/03L-0, Reactor Coolant Conductivity Exceeded 2 Micro Mhos/Cm While in Operational Condition 2.

-- 83-007/03L-0, Average Power Range Monitor Scram and Rod Block Setpoints Were Not Within Tolerances.

-- 83-008/03L-0, Both Control Structure Chlorine Detectors Were Inoperable.

-- 83-009/03L-0, Average Power Range Monitor Channel "D" Failed The Weekly Functional Check.

-- 83-011/03L-0, "C" Diesel Generator Was Declared Inoperable After Determination Was Made That The Air Start Receiver Pressure Was Below Technical Specification Limits.

*-- 83-012/03L-0, Reactor Recirculation Pump "A" Was Declared Inoperable After Tripping Off Line.

-- 83-013/03L-0, "As-Found" Data For The Reactor Vessel Water Level "A" Channel Was Lost Due to Incorrect Test Equipment Usage.

*-- 83-014/03L-0, Reactor Recirculation Pump "A" Motor-Generator Set Tripped With The Unit in Power Operation.

-- 83-015/03L-0, Control Rod Was Declared Inoperable After Failing To Move On A Withdrawal Signal During a Normal Startup.

-- 83-016/03L-0, Reactor Coolant System Conductivity Exceeded the Technical Specification 3.4.4.1.a Limit of 10 Micromho/Cm at 25^{o}C. The Limit Was Exceeded For Less Than 1 Hour.

-- 83-017/03L-0, Rod Worth Minimizer Was Bypassed With Power Less Than, Or Equal to 20%. This Is A Limiting Condition Of Operation Per Technical Specification Section 3.1.4.1.

-- 83-018/03L-0, APRM Channel "B" Flow Biased Rod Block and Scram Setpoints Were Less Conservative Than The Value Required For 100% Power.

-- 83-020/03L-0, Control Structure Chlorine Detector "A" Was Inoperable.

**-- 83-026/01T-0, Inoperability of Both Trains of The Standby Gas Treatment System.

* Denotes those reports selected for onsite followup. (See Paragraph 8).

** Followup of this report is discussed in Paragraph 9.

8. Licensee Events

a. RHR Room Spill

On January 7 a spill of approximately 5000 gallons of reactor coolant occurred in the Residual Heat Removal Room "A" (RHR). The spill occurred with the plant in operational condition 4 with the "A" loop of RHR in the shutdown cooling mode with RHR pump "C" running.

At approximately 4:00 a.m. a Nuclear Plant Operator discovered water on the floor of the RHR room, and determined that the suction relief valve (PSV 1F030A) was lifting, putting water onto the floor of the RHR room. Since the floor drains are kept closed for protection against ECCS room common mode flooding the water did not drain, but stayed in the RHR room until discovered by the operator.

The licensee determined the relief valve had operated to relieve pressure buildup in the suction line of the idle RHR "A" pump. The pressure buildup was caused by not opening the suction valve (1F006) to the idle pump and by a leaking minimum flow discharge check valve (1F046A) which allowed the idle RHR suction line to pressurize.

The licensee disassembled the minimum flow discharge check valve between January 17 and 19 and found that the valve was properly seated, but showed signs on the disc that the disc had been seating off-center, and that there was some wear on the disc pin allowing movement of the disc. The licensee replaced the pin and installed new bonnet gaskets. The work is documented in Work Authorization S33048.

A water sample taken of the water on the floor of the RHR room at 4:04 a.m. indicated a total activity of 1.86×10^{-2} micro curies per milliliter. The room was drained to the reactor building sump and processed via the liquid radwaste system.

The licensee has commenced decontamination of the room as documented in Radiation Work Permits (RSP) 83-19 and 83-67. Maximum radiation exposure any individual received during this decontamination effort was 15 millirem as documented in RWP 83-67. A standing RWP (S83-24) is still in effect for entering the room since surveys of the floor still indicate contamination with levels from 1000 to 42,000 disintegrations per minute (dpm) per foot squared, with some localized spots indicating readings as high as 42 millirem per hour contact readings. The licensee plans further decontamination of the room.

On February 14 and March 7 the inspectors reviewed the Work Authorizations, Radiation Work Permits and action taken by the operators, and found no unacceptable conditions. The plant management reviewed the event with plant operating personnel and stressed the importance of opening the suction on idle RHR pumps while in shutdown cooling to prevent overpressurization of the suction piping.

No unacceptable conditions were noted.

b. Reactor Water Cleanup Phase Separator Room Spill

On January 21 the licensee reported that the "A" Reactor Water Cleanup (RWCU) Phase Separator had overflowed and spilled radioactive liquid and resin onto the floor. The room is in the Radwaste Building and is normally an isolated room. At the time of the spill the phase separator pump was operating in the recirculation mode with the phase separator tank full. Sealing water for the pump is discharged into the phase separator tank. This seal water caused the tank to overflow into the room spilling approximately 450 gallons of water and resin onto the floor. An operator discovered the spill on the floor during his rounds.

The licensee subsequently determined on January 27, 1983 that the high level alarm setpoint for tank level had drifted such that the alarm would not be received even with the tank full.

The water in the room was removed via the room drain, which drains to the Liquid Radwaste System. The resin was removed on January 28 as documented on Radiation Work Permit (RWP) 83-58. The highest individual dose received by any worker during this work was 30 millirem as documented in the RWP.

As of March 7 the licensee has not attempted to decontaminate the room due to high radiation background reading in the room caused by the resin in the separator tanks. The inspectors confirmed that the room is completely isolated with a standing RWP (S83-25A) issued to control entry into the room.

c. Recirculation Motor-Generator Trips (LER 82-76, 83-12, 83-14)

On February 4, 1983 at approximately 3:10 p.m. the "A" recirculation motor pump tripped while the reactor was operating at 100% of thermal rated power. The pump trip caused reactor power to decrease to 65% power. The trip was caused by a blown fuse in the exciter control circuitry. This trip seemed to parallel other trips of the "A" recirculation motor generator which had occurred on January 13 and 19. After the trip on January 19 additional recorders were installed to monitor the motor generator exciter circuitry. The licensee reviewed this data after the trip on February 4, and determined that prior to the fuse blowing the exciter output current increased from a normal of 3.2 amps to 17.5 amps and that generator output voltage increased by 15%. This condition lasted for approximately 15 seconds at which time the fuse to the exciter power supply blew, followed by the generator field breaker tripping, shutting down the recirculation pump. The licensee replaced the exciter regulator with one from a Unit 2 motor generator set, after testing could not determine which components were malfunctioning. The licensee tested the new regulator, and restarted the "A" recirculation pump in accordance with procedures at 1:00 a.m. on February 5. On February 7, the inspector reviewed the data taken, and licensee actions with members of the Electrical Maintenance Department. The replaced regulator was bench tested under 100% load to see if a breakdown of components would occur.

On February 15 the licensee reported two Silicon Controlled Rectifiers (SCR) in the replaced regulator unit had malfunctioned under the test load condition, and would have resulted in the type of trips the unit had experienced while installed in the motor-generator control circuitry.

No unacceptable conditions were noted.

d. Reactor Trip During Stop Valve Testing

On January 25, the Unit 1 reactor tripped from about 70% power while the No. 3 turbine stop valve was being operated for a surveillance test. While the No. 3 stop valve was still opening a No. 4 stop valve "not full open" signal was received. This resulted in a half-scram condition and a recirculation pump trip. The recirculation pump trip resulted in an APRM flow biased flux trip in the other reactor protection channel and a reactor trip. The inspector discussed this event with the operator, shift supervisor, and Instrumentation and Controls Supervisor, and reviewed the control room chart recorders and computer sequence-of-events log to independently verify the licensee's conclusions. During this review the inspector noted two problems. First the 'A' recirculation pump drive flow recorder was still indicating a steady flow rate after the pump had tripped. The incorrect indication was due to a stuck pen. Work Authorization S36311 was initiated on January 25 to correct this problem. On subsequent control room visits the pen was noted to be operating properly.

The second problem was with Figure 7.2-1, sheet 4 of the FSAR, which describes the recirculation pump trip logic. The FSAR drawing indicates that a recirculation pump trip will occur if turbine stop valve No.'s 1 and 3, or 2 and 4 close. However, the recirculation pump trip occurs when stop valve No.'s 1 and 2, or 3 and 4 are closed. This is in agreement with the approved design drawings. An FSAR change request was submitted on January 27 to revise the incorrect drawing. The inspector will verify implementation of the change during a future inspection. (387/83-03-04)

The licensee was unable to pin-point the cause of the No. 4 stop valve "not full open" signal. One possible cause would be the spurious actuation of both No. 4 stop valve limit switches. Another possibility would be the premature testing of valve No. 4 before valve No. 3 had fully opened.

An inspection of the limit switches was made, and no problems were found. To ensure that one stop valve is fully open before the next valve testing begins, a new step was added to the procedure which requires the operator to verify the valve "open" via computer points NPZ01, 02, 03, and 04, and to stroke the valves in the sequence 1-4-2-3, thus receiving only a half-scram if two valves in the sequence both indicate "not full open", instead of a recirculation pump trip.

No unacceptable conditions were identified.

9. Standby Gas Treatment System (SGTS) Inoperability

On March 2 at about 12:30 p.m. the licensee reported to the NRC Resident Inspector that both trains of the Standby Gas Treatment System were inoperable for a period of about 24 hours on February 28 and March 1. The inoperability reportedly resulted from an improper equipment tag-out.

The SGTS is designed to accomplish the following safety related objectives:

a. Exhaust sufficient filtered air from the reactor building to maintain a negative pressure of about 0.25" water in the affected volumes following secondary containment isolation for the following design basis events:

    (1) Loss of Coolant Accident

    (2) Spent fuel handling accident in the refueling floor area

b. Filter the exhausted air to remove radioactive particulates and both radioactive and nonradioactive forms of iodine to limit the offsite dose to the guidelines of 10 CFR 100 and,

c. Filter and exhaust discharge from the main steam isolation valve leak control system.

A simplified version of the SGTS is appended to this report as Attachment 1.

Inspector review of this event, including discussions with operators, technicians, licensee management and review of available documentation and records determined the following:

a. On February 28 at 11:20 a.m. the licensee removed SGTS subsystem A from service to remove test cannisters from the charcoal filter beds. To provide personnel protection the licensee determined that cross-tie dampers (between the A and B subsystems) TD 07560A and TD 07560B were required to be blocked shut. The operator accomplished this by opening circuit breaker 11 on panel 1Y236 and breaker 11 on panel 1Y246. By opening these breakers the licensee not only disabled the power supply to the cross-tie dampers, but also disabled both trains of the Standby Gas Treatment System. The breakers supply control power to the SGTS fans A and B discharge vanes (FD-07551A and B). With the breakers open the discharge vanes will not open on the initiation of the SGTS, thus rendering both trains inoperable. By 11:15 a.m. on March 1 the test cannisters had been removed from the filter bed and all permit tags were removed. The breakers on panels 1Y236 and 1Y246 were not shut since the operators intended to subsequently install a permit on train "B" of the SGTS to remove test cannisters.

At approximately 11:30 a.m. the licensee attempted to start the "A" train of the SGTS. The "A" fan started, then tripped after 15 seconds on low flow. The #11 breakers on panels 1Y236 and 1Y246 were then shut, and the system was retested. The first retest was unsuccessful due to an unrelated SGTS heater problem, but a subsequent retest demonstrated proper system operation for the "A" subsystem, which was declared operable at 12:10 p.m. on March 1, 1983.

At this time operators began questioning the operability of both trains with the circuit breakers open. By 3 p.m. the licensee had determined that both trains were inoperable from February 28, 11:28 a.m. until March 1, 12:10 p.m., and determined that this was a 24 hour reportable event.

Technical Specification 3.6.5.3 requires two independent Standby Gas Treatment Subsystems to be operable in Operating Conditions 1,2,and 3. The associated TS Action Statement 3.6.5.3.a allows continued operation for 7 days with one subsystem inoperable. TS 3.0.3 states that when a Limiting Condition for Operation is not met, except as provided in the associated action requirements, within one hour action shall be initiated to place the unit in an Operational Condition in which the specification does not apply.

Contrary to the above, from February 28, 1983 at 11:25 a.m., until March 1, 1983 at 12:10 p.m., with the unit in Operational Condition 1 (Power Operation), both subsystems of the SGTS were inoperable such that the Limiting Condition of Operation 3.6.5.3 and associated Action Statement were not met and no action was taken to place the unit in Operational Condition 4 (Cold Shutdown) as required.

10 CFR 50.72, Notification of Significant Events, requires that the licensee notify the NRC Operations Center as soon as possible, and in all cases within one hour, of the occurrence of any significant events including;

(1) Personnel error or procedural inadequacy which, during normal operations, occurrences, or accident conditions, prevents or could prevent, by itself, the fulfillment of the safety function of those systems important to safety that are needed to limit the release of radioactive material to acceptable levels; and

(2) Any event requiring initiation of shutdown of the plant in accordance with Technical Specification Limiting Conditions for Operations.

Contrary to the above, the required report was not made within one hour of licensee determination (about 3 p.m. on March 1, 1983) of the inoperability of the Standby Gas Treatment System. Additionally, the Technical Specification Limiting Condition for Operation required initiation of a shutdown because of the Standby Gas Treatment System inoperability.

b. Numerous indications in the control room and several alarms were received which should have indicated to the operators that the breakers opened on 1Y236 and 1Y246 supplied more than just the crosstie dampers. The following damper indications were lost on Control Room Panel OC 681:

-- FD-07551A2 and B2 - SGTS A and B train outside air makeup dampers.

-- HD-07555A and B - SGTS A and B outside cooling air dampers.

-- HD-07552A and B - SGTS A and B filter exhaust dampers.

-- HD-07553A and B - SGTS A and B filter inlet dampers.

-- PD-07554A and B - Reactor Building Recirculation Dampers to SGTS.

The following instrument indications were lost on Control Room Panel OC 681:

-- PDI-07554A1 and B1 - Reactor Building (Zone 1)-to-outside differential pressure indication.

-- PDI-07554A2 and B2 - Reactor Building (Zone 2)-to-outside differential pressure indication.

-- PDI-07554A3 and B3 - Reactor Building (Zone 3)-to-outside differential pressure indication.

-- PDIC-07554A and B - Reactor Building-to-outside differential pressure indication and control indication.

-- FI-07557 - Recirculation to SGTS flow indication.

-- FIC-07551A and B - SGTS air flow indications.

-- FR-07553A and B - SGTS air flow recorders.

The following alarms were received in the control room:

-- SGTS instrument power failure alarm, train A and B.

-- SGTS "A" out of service alarm.

The Control Room Operator's (CRO) log, the Shift Supervisor's log, and the Control Room Operator's turnover check-off list were reviewed for February 28 and March 1. There were no entries made indicating alarms existed in the control room panels for the SGTS, that damper indication was lost, and that any action was taken to discover why alarm/indications were abnormal.

The license's review of the event indicated that even though their actions were not recorded in the operator's logs the operators had responded to the SGTS instrument failure alarms by following alarm response procedure AR-29-001, Revision 0, and had determined that opening the #11 breakers on 1Y236 and 1Y246 would give the instrument failure alarms. However, the alarm procedure was inadequate in that it did not indicate that the alarm was also indicative of an inoperable SGTS subsystem, and the required operator action did not lead the operator to check operability of the SGTS. The A subsystem alarms were expected due to the equipment tagouts. The operators did not adequately investigate the B subsystem alarm and indications.

Administrative Procedure AD-QA-303, Revision 0, "Shift Routine" states in Section 6.1.6 that oncoming personnel shall complete and sign the appropriate section indicating the Control Room Panels and alarms have been reviewed and in Section 6.2.5 that log entries should include occurrences of significant annunciator alarms and actions taken in response to the alarm.

Technical Specification 6.8.1.a requires approved procedures as specified by Regulatory Guide 1.33, Revision 2. Regulatory Guide 1.33, Revision 2, Appendix A, Paragraph 5, states that abnormal, off-normal, or alarm condition procedures should contain the immediate automatic action, the immediate operator action, and the long range action.

Contrary to the above, Alarm Response Procedure AR-29-001, Revision 0, did not indicate that a SGTS Instrument Failure Alarm could indicate a loss of the SGTS train and that the operators should investigate the SGTS subsystem operability.

Administrative Procedure AD-QA-306, Revision 2, "System/Equipment Release" states in Section 6.4 and Attachment B that Shift Supervision should review the Equipment Release Form (ERF) for completeness regarding the equipment and blocking requested, and ensure adequate levels of system availability will exist after removal of the equipment/system to maintain safe operation.

Administrative Procedure AD-QA-103, Revision 2, "Protective Permit and Tag System" states in Section 6.4.1.c that upon receipt of the ERF containing the blocking request, shift supervision will evaluate the request in accordance with AD-QA-306 Section 6.4, taking into consideration such factors as Technical Specifications and adequacy of blocking. Section 6.4.2.a states that after Shift Supervision concurs with the blocking request, the Systems Operating Representative shall be directed to complete the permit. Section 6.4.2.c states that the Shift Supervision will initial the permit when the system or equipment is released by Shift Supervision's signature on the ERF.

In dispositioning ERF number A0113 (prior to removal from service of the "A" SGTS), the Unit Supervisor (Shift Supervision) determined that the blocking requested on the ERF form could not be accomplished since some of the dampers requested to be shut would fail open on loss of electrical power to the dampers. He decided that opening breaker for fan OV109A, breaker #11 on Panel 1Y236, and breaker #11 on Panel 1Y246 would provide sufficient protection. Permit 1-83-281 was written by the Systems Operating Representative (the Plant Control Operator) and approved by the Unit Supervisor documenting the decision on the blocking. The Unit Supervisor also approved ERF-A.0013.

Contrary to Administrative Procedure AD-QA-306, Section 6.4 and Attachment B, the review performed by the Unit Supervisor was inadequate since it did not prevent the removal of both subsystems of the SGTS.

Two factors contributed to the operator's inadequate review of the blocking. First, the design drawings were not intended to facilitate blocking reviews by an operator, and the review process was very complex (generation of a controlled set of electrical load lists is in process but not completed); second, the series of drawings needed for an adequate review were not all available in the Control Room. The inspectors needed the following drawings to determine what loads would be lost when the breakers were opened:

-- PP&L Drawing E-25, Sheet 1, Revision 2

-- PP&L Drawing E-201, Sheet 6, Revision 6

-- PP&L Drawing E-362, Sheet 5, Revision 5

-- Vendor Print (V/P) 8856-M334-27

-- PP&L Equipment Index Sort 32

The vendor and the E-362 drawings were not in the Control Room, and although an equipment index was available, sort 32, which is the one required to identify panel loads, was not.

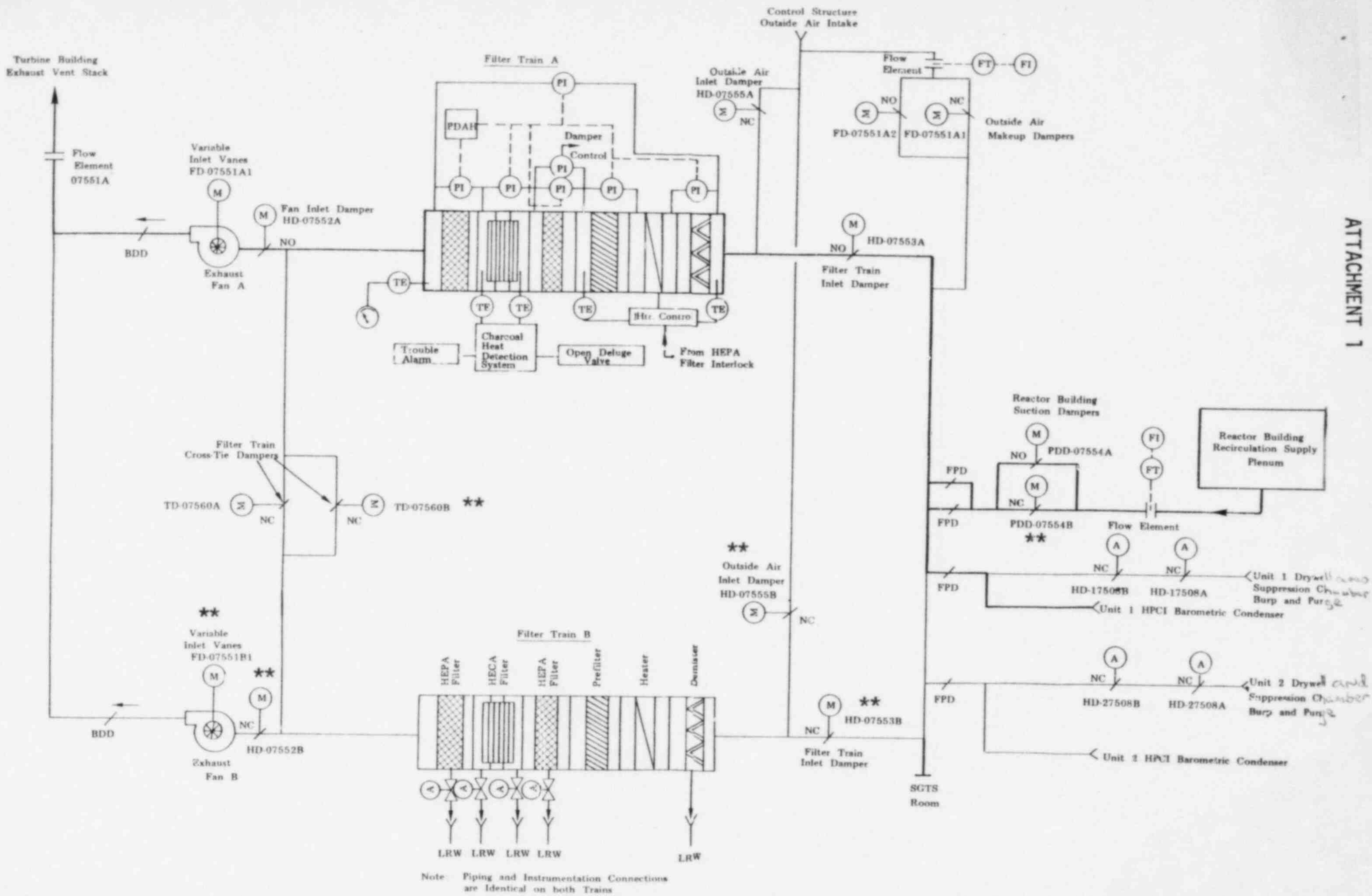
The inoperability of both Standby Gas Treatment Subsystems and the breakdown in administrative and procedural controls which contributed to this inoperability is an apparent violation (387/83-03-02). Failure to make a report within the required time period is also an apparent violation (387/83-03-03).

10. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations, or deviations. Unresolved items are discussed in Sections 3.a and 3.b.

11. Exit Interviews

During the course of this inspection, meetings were held with H. Keiser or D. Thompson to discuss the inspection and findings identified, in Unit 1, and with R. Beckley to discuss the inspection and findings identified in Unit 2.



STANDBY GAS TREATMENT SYSTEM SIMPLIFIED SCHEMATIC

** These "B" train dampers and components receive power through circuit breaker No. 11 on panel 1Y246. "A" train disabled for maintenance.

ATTACHMENT 1