U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-387/82-32
50-388/82-05

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

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

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

Facility Name: Susquehanna Steam Electric Station

Inspection At: Salem Township, Pennsylvania

Inspection Conducted: September 8 - October 19, 1982

Inspectors: Gary G. Rhoads — 10/19/82 date
Gary G. Rhoads

John F. McCann — 10/19/82 date
John F. McCann

J. W. Chung — 11/3/82 date
J. W. Chung

Approved by: Ebe McCabe — 11/3/82 date
Ebe C. McCabe, Chief, Reactor Projects Section 2B, DPRP

Inspection Summary: September 8 - October 19, 1982 (Combined Reports 50-387/82-32, 50-388/82-05).

Routine resident (171 hours Unit 1, 41 hours Unit 2) and regional inspection (68 hours Unit 1) of: Preoperational test results review; Startup Test results review; Startup test witnessing; Licensee event followup; Welding activities; Technical Specification Compliance, Open items and Plant status. Two violations were identified pertaining to Unit 1; security violation pertaining to vehicles in protected area, and licensee not meeting requirements for operable fire protection equipment. One violation was identified pertaining to Unit 2; Improper storage of safety-grade pipe.

Region I Form 12
(Rev. February 1982)

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DETAILS

1. Persons Contacted

Pennsylvania Power and Light Company

R. Beckley, Resident NQA Engineer
S. Denson, Project Construction Manager
M. Detamore, Plant Engineering Supervisor
A. Dominguez, Sr. Project Engineer
F. Eisenhuth, Sr. Compliance Engineer
R. Featenby, Assistant Project Director
E. Figard, ISG Supervisor
J. Green, Supervisor, Operations Quality Assurance
M. Johnson, Record Control Group Supervisor
H. Keiser, Superintendent of Plant
G. Kuczynski, Electrical Maintenance Supervisor
B. Lloyd, Mechanical Maintenance Supervisor
R. Matthews, Sr. Analyst - NQA
R. Sheranko, Startup & Test Field Engineer
J. Zentz, Test Coordinator

Bechtel Corporation

G. Bell, Project QA Engineer
N. Covington, Assistant ISG Supervisor
H. Foster, San Francisco Home Office - QC
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 Previous Inspection Findings

a. (Closed) Inspector Followup Item (387/82-16-01) Correct LLRT Results for 45 PSIG.

The correction factor was small, and only a small number of LLRT's were conducted below 45 psig, and the uncorrected value of total LLRT leakage results were well below the acceptance criterion of 0.6 La. The inspector determined that the final corrected results met the acceptance criterion. This item is considered closed.

b. (Open) Unresolved Item (387/82-16-02) Correct ILRT Results for CRD Headers Not Vented and Safety Analysis of CRD Line Breaks.

During the ILRT, only one of the four non-seismic headers of CRD piping system, namely CRD charging header, was vented which resulted in liquid leakage of approximately 2.5 gpm. The other three non-seismic headers (cooling water, drive water, and exhaust) were not vented during the test due to an oversight. The licensee had agreed to correct the ILRT results for CRD headers not vented and evaluate the matter for potential safety significance. See Inspection Report 387/82-16, Paragraph 4.5 for details.

After the ILRT, with containment at pressure, the remaining headers were vented and the liquid leakage increased by approximately 0.5 gpm (equivalent to 0.006 wt. %/day). Licensee concluded that the venting of these remaining headers did not cause gross leakage and did not significantly affect ILRT results. See Reactor Containment Building ILRT Unit 1 Final Report, May 1982, Section 3.5.4, for details.

However, the above report did not contain an evaluation of CRD line breaks for potential safety significance. Pending this evaluation, this item is considered unresolved and remains open.

c. (Closed) Construction Deficiency (388/81-00-35) Oversize Hole in Power Head of Cooper Energy D/G.

This problem was reviewed during NRC inspection 387/82-03; 388/82-02 and closed for Unit 1. The diesels are a common system and therefore this problem is also closed for Unit 2.

d. (Closed) Construction Deficiency (388/82-00-03) Inconsistencies in Vertical Dynamic Model for Reactor/Control Building.

This issue was closed during inspection 387/82-19 for Unit 1 only, but should have been closed for both Units.

e. (Closed) Part 21 Report (388/82-88-01) Goldfish in Spray Pond May Plug Heat Exchangers.

This item was closed for Unit 1 only during inspection 387/82-19. The spray pond is a common system, therefore this item is closed for Unit 2.

f. (Closed) IE Circular 78-17 (388/78-CI-17) Inadequate Guard Training/Qualification and Falsified Training Records.

This item was closed for Unit 1 in NRC inspection 387/82-05. Since the same licensee security force will be used for Unit 2, this item is also closed for Unit 2.

g. (Closed) Unresolved Item (388/79-13-04) Procedures for Solid Waste Disposal.

This item is common to Unit 1 and 2, and should have been closed for both units during inspection 388/80-18.

3. Plant Tours

The inspector conducted periodic tours of accessible areas in the plant during normal and back-shift hours. During these tours the inspector observed housekeeping and cleanliness controls, construction work in progress, testing, maintenance, in-plant storage and protection of equipment, security measures, and proper equipment line-up.

On October 7, 1982 the inspector found inadequately protected piping material stored outside the back of the piping combination shop. Bechtel Field Procedure FP-G-11, Revision 23, "Procedure for Storage, Protection, Maintenance and Lay-Up", paragraph 2.3, requires that specified caps, plugs or closures be kept in place on all piping and pipe fittings, and that stainless steel piping stored outside be covered with approved tarps with adequate air circulation. The inspector found internally rusted carbon steel piping without protective caps or closures, and stainless piping which was uncapped and not covered with a tarp. Some of this piping was color-coded for safety related use.

This problem was immediately brought to the attention of the licensee for prompt correction.

On October 15, 1982, the inspector noted that the piping behind the piping combination shop was properly protected from the weather. Failure to properly protect stored piping materials is a violation of the licensee's PSAR Appendix D pertaining to Unit 2. (388/82-05-01)

4. Initial Start-Up

Activities associated with initial startup were reviewed to ensure that Technical Specifications and other license conditions were met, that administrative requirements and procedures were adequate and in use, and that test results were properly documented and evaluated.

Rod withdrawal began at about 9:06 P.M. on September 10, 1982 and criticality was achieved at 11:17 P.M. on September 10. Conditions during the startup were as expected. At about 11:58 P.M. a reactor scram occurred when the operator inadvertently switched to a lower range of the Intermediate Range Monitoring System (IRM) while still above the upscale trip set-point for that range. The cause of the error was an incorrect indication on the video display of IRM level. The incorrect indication was later found to be a computer software problem. Conditions during the shutdown were as expected. The startup activities were also reviewed by a region-based inspection team are reported in NRC Inspection Report No. 387/82-37.

5. Commissioner Visit

Commissioner Victor Gilinsky visited the site on September 13, 1982 to review plant readiness for operation. The trip included a plant tour and discussions with the resident inspector and senior licensee management. Principle areas of interest were TMI action plan items, operator training and experience, senior licensee management experience, current enforcement activities, control room characteristics, the Mark II Containment program, and emergency procedures and facilities.

6. Preoperational and Startup Test Exceptions

The inspector met with the Integrated Startup Group (ISG) Supervisor and his staff to discuss preoperational and acceptance test exceptions still outstanding. With the exception of P100.1, Cold Functional Testing and A85.2, Freeze Protection, all other test exceptions were transferred to Plant Staff to be resolved. The remaining exceptions of P100.1 are in the process of being resolved by the modification and changes being made to the Emergency Service Water System, to eliminate the water hammer problem encountered during operation and testing. A85.2 testing is now in progress for freeze protection requirements.

The inspector discussed the exceptions to the following tests, with cognizant members of plant staff:

P34.1 RBHV	A32.5 SCCHV
P45.1 FW	A39.1 CD
P55.1 CRDH	A41.1 CT
P56.1A RMCS	A65.2 RWBFW
P79.2 STBVS	A67.1 VLPM
P79.2D OGT	A69.2 LRWO
P81.1 FHSE	A76.2 PS
P83.1A ADS/SR	A85.1 CP
	A98.1 MGE
	A99.1 P
	A99.4 RMD

Findings

Disposition and resolution of exceptions to the list of completed tests is in progress and will be followed up by the inspector for final resolution and completion as part of the routine inspection program.

7. Quality Assurance Audit of Test Program

At the request of PP&L, Gilbert Associates Inc. performed a quality assurance review to determine that test commitments established in the FSAR were adequately incorporated in the acceptance criteria for the preoperational testing of Unit 1 systems and components. The inspector reviewed the Gilbert report and licensee response and noted the following:

a. The reviewers encountered discrepancies between FSAR testing commitments and the specific preoperational test acceptance criteria. Although the PP&L response verified that the testing was performed in either a component test or in the body of the preoperational test it was recommended that for Unit 2 the preoperational test acceptance criteria be expanded to better equate with FSAR commitments.

b. In several cases Design Change Packages had been performed on systems without making an appropriate change to the FSAR to reflect the Design Change Package. This made FSAR testing requirements oudated. It was recommended that an administrative system be implemented to ensure that before a Design Change Package is closed out, any required FSAR changes are submitted.

c. Two specific instances of differences between FSAR test commitments and preoperational test acceptance criteria required resolution. In one instance testing was performed to acceptance criteria different from the FSAR. In the second instance preoperational test acceptance criteria addressing an implied FSAR test commitment were not included. These differences were resolved and the required testing was completed.

d. Gilbert Associates determined that with the exception of the two instances noted above, and within the constraints of the scope of the Gilbert Associates review, the preoperational test acceptance criteria for SSES Unit 1 systems and components, and the explanations provided by PP&L, adequately addressed the implicit and explicit test commitments contained in the FSAR through Revision 29.

The inspector concluded that the Quality Assurance Review conducted by Gilbert Associates was adequate and had no further questions on their findings.

8. Safety Related Pipe Welding

The inspector observed the preparation and welding of two safety related pipe joints to determine if the following conditions were met:

-- The work was conducted in accordance with a weld data sheet, form WR-6, and the appropriate QC sign-offs were completed.

-- The welding procedure specification assignment is in accordance with applicable ASME code requirements.

-- The base metals, welding filler materials and gases were of the specified type and were traceable to test reports or certifications.

-- The welders were currently qualified for the process and were identified on the weld data sheets.

-- Welding equipment including power cables and gas lines were in serviceable condition.

-- Weld joint geometry was as specified and the surfaces to be welded have been prepared, cleaned and inspected.

-- Tack welds were made by qualified welders and were ground out as required.

-- Pre-Heat and interpass temperatures were controlled as required.

-- Interpass cleaning and grinding were properly performed.

The welds observed were Field Weld No. 14 on SP HCB209, a butt weld in a wetwell atmosphere sampling line, and Field Weld No. 35 on SP HCB205-1, a butt weld to the suction valve of the 'B' standby liquid control pump.

The inspector also examined welding material control at the disbursal points on the 719' elevation of the Unit 2 reactor building and in the piping combination shop to verify that:

-- Welding material was properly heated and that the ovens were properly calibrated.

-- Welding material was properly segregated.

-- Welding material is only issued to properly qualified welders for the weld process.

No unacceptable conditions were identified.

As a result of previous NRC inspector concerns about the experience of two Bechtel radiograph reviewers, PP&L Construction Quality Assurance re-examined 67 weld radiography packages (29 Unit 1, 38 Unit 2). Three Unit 2 welds were determined to need further evaluation and are documented on Bechtel Non-Conformance Report (NCR) 9692. As a result of these PP&L findings, Bechtel Management Corrective Action Request (MCAR) No.1-83 was issued to examine 10% of the weld radiography packages reviewed by the individuals who's experience was questioned by the NRC inspector, and 20 weld packages from each of the other reviewers. This sample consisted of 673 welds (267 Unit 1 and 406 Unit 2).

Seven welds were determined to need further evaluation. Three of these were for Unit 2 and are documented on Bechtel NCR No.'s 9776 and 9822. The status of four Unit 1 welds identified as needing further evaluation is described below:

Weld	Location	Discussion
DLA-101-1; FW5	Feedwater System	This radiography package was missing; the weld was re-radiographed and found acceptable. (PP&L NCR No. 188)
DLA 101-1; FW7	Feedwater System	Linear indications were seen in a 1979 radiograph near the edges of the film. The weld was re-radiographed with the suspected area in the center of the film and no indications were seen. They were apparently slight surface defects which were removed when preparing the weld for Ultasonic testing. (PP&L NCR No. 212)
DBB 102-1; FW10	Main Steam (Outside Isolation Valves)	The reviewer felt the weld may be less than minimum required wall thickness. This was documented on PP&L NCR No. 207. It was found that the weld thickness was less than 87% of the manufacturers minimum wall thickness, but well in excess of the design minimum wall thickness. Acceptability of the weld for use as-is will be determined by the licensee after review of radiographs scheduled for October 21, 1982.
DBD 105-1; FW4	Startup flow control piping in Main Feed (Not ASME Code Weld)	A surface gouge was found and ground out. This is documented in PP&L NCR No. 189.

The inspector will continue to follow the resolution of Unit 2 weld questions identified in Bechtel NCR Nos. 9692, 9776, and 9822. (388/82-05-02)

9. Fire Protection

On October 12, 1982 the inspector noted an entry in the control room Limiting Conditions for Operations Log (LCO Log) dated October 10, 1982 which stated that certain fire detectors in Fire Zone 1-7A required by Technical Specification were not in the Fire Zone. The inspector then questioned the Plant Fire Protection Engineer who stated that although the Technical Specifications required nine ionization detectors, and two photo-electric detectors in Zone 1-7A, it had been found during surveillance testing that there were actually thirteen ionization detectors and no photo-electric detectors.

The inspector then asked why this discrepancy had not been found during initial surveillance testing. The Fire Protection Engineer stated that pre-operational testing had been used as the basis for determining initial operability of the ionization and photo-electric detectors in lieu of the actual surveillance test. Apparently the discrepancy had been missed when reviewing the preoperational test for surveillance confirmation.

The inspector next reviewed surveillance data sheets for functional testing of the fire protection instrumentation. The following problems were identified:

a. Surveillance data sheets for functional testing of fire protection heat detectors (SI-13-201) completed on July 24 and July 30 did not include testing of the heat detectors in Fire Zone 0-27E.

   The inspector then reviewed Work Authorization (WA) S28045 completed on July 30, 1982 which documented maintenance on the heat detector circuitry. Although the WA recommended functional testing of the heat detectors circuitry as part of the WA closeout, the licensee could not verify that the testing had been completed. On October 15, the licensee delcared the heat detectors in Zone 0-27E inoperable, and performed appropriate surveillances.

b. On October 14, 1982 the licensee determined that Fire Zone 1-7B did not have any ionization detectors even though two were required by Technical Specifications. The licensee commenced a fire watch of this area of the Reactor Building. The licensee had previously declared this zone operable by testing two ionization detectors which were actually located in Fire Zone 1-7A, not 1-7B. On October 18, 1982 the inspector informed the Superintendent of Plant that not having operable ionization detectors in Fire Zone 1-7B and not having documentation to show the heat detectors in Fire Zone 0-27E were operable was a violation of Technical Specification 3.3.7.9. (387/82-32-04)

On October 15, 1982 the licensee initiated a system walkdown to locate all fire protection detectors in the plant. The following additional discrepancies were noted:

a. Fire Zone 1-4B (TIP Room) has only one ionization detector, and three photo-electric detectors. Technical Specification table 3.3.7.9-1 states that there are two ionization detectors and no photo-electric detectors in this zone. The Technical Specification states that a minimum of one ionization detector in this area is required to be operable. The inspector verified that surveillance had been completed on the one ionization detector and that it was operable.

b. The review determined that the Technical Specification table 3.3.7.9-1 entries for Fire Zones 0-25A and 0-25E were reversed for heat detectors. The table stated 26 heat detectors existed in Zone 0-25A and 20 in Zone 0-25E. Actually 26 detectors exist in 0-25E and 20 in 0-25A. The inspector confirmed that the minimum required heat detectors were operable in both zones.

c. Many areas of the plant were determined to have more detectors than stated in Technical Specifications.

The inspector discussed these discrepancies with the Assistant Superintendent of Plant on October 18, 1982. The inspector stated that the discrepancies with the Technical Specifications should be reconciled. The licensee's actions will be reviewed during a subsequent NRC inspection. (387/82-32-05)

10. RPS Cable

On October 6, 1982 the Assistant Superintendent of Plant informed the Resident Inspectors that the licensee had discovered Reactor Protection System (RPS) cabling which was not properly grounded in the upper and lower relay rooms. He stated that the licensee intended to ground the cables during the present outage. This item had been previously considered closed by the licensee as documented in NRC Inspection Report 387/82-19, based on documentation of properly grounded cabling in Quality Control Inspection Reports (QCIR) NSSS-25676 and NSSS-25675. During subsequent licensee inspections of the RPS panels it was noted that although ground wires were connected to the flexible conduit of certain RPS cables, they were not connected to a grounding bus bar. On October 13 1982 the Resident Inspector discussed the QCIR with the responsible Bechtel Quality Control (QC) Inspector, who could offer no explanation for the discrepancy. The inspector then discussed this issue with the licensee's Nuclear Quality Assurance Manager, and Resident Quality Assurance Engineer stating that this discrepancy in conjunction with other recent Quality Control inadequacies in the small and large pipe hanger program indicated a need for increased licensee attention in this area. Licensee actions will be reviewed during a subsequent NRC inspection. (387/82-32-06)

Additionally the licensee determined that a revision to the General Electric Field Deviation Disposition Report (FDDR)-607 (Revision 4), which was issued to the licensee in August, 1982, indicating additional RPS cables to be grounded had not been completed, but was also scheduled for this outage.

On August 13, the licensee directed the Nuclear Safety Assessment Group (NSAG) to investigate the sequence of events on the modification to ground the RPS cable and to determine why the modification had not been properly completed even though it was a license condition to do so. The licensee also performed a 100% re-inspection of RPS cabling to assure that all RPS cables were properly grounded on October 16 and 17, and identified four additional cables which were not grounded. The NSAG report and licensee corrective actions will be reviewed by the NRC during a subsequent inspection. (387/82-32-07)

11. Fire in ESW Pumphouse

On September 22 at 9:35 a.m. the licensee declared an Alert Condition in accordance with their Emergency Plan when an electrical fire broke out in electrical panel OB-517 in the Emergency Service Water System (ESW) Pumphouse. The Resident Inspector observed licensee actions in the Control Room and the Technical Support Center from the time the licensee made the Emergency Notification System (ENS) call to the NRC until the Alert was downgraded. The event was terminated at 10:35 a.m. The fire rendered inoperable the RHR servicewater bypass valve for the A loop which also made automatic initiation of the ESW system inoperable. The event was started when a Bechtel electrician dropped a ground cable across one phase of the incoming power to panel OB-517, and resulted in the melting of bus bars in the panel. The fire was put out by opening the supply breaker to the panel and spraying the panel with dry chemical fire extinguisher. The licensee has determined that the electrical distribution system worked as designed and is investigating to determine if the fire protection system was adequate. The licensee completed restoring the electrical panel on September 23, 1982. Two Region I inspectors investigated the event on September 23 and 24. No unacceptable conditions were noted. A review of the licensee's investigation of fire protection adequacy will be reviewed during a subsequent NRC inspection. (387/82-32-08)

On September 27, 1982 the inspector discussed the event with the on-duty Luzerne County Civil Defense Supervisor. The Supervisor stated that communications of the incident with the licensee were proper and adequate and that no serious communications problem occurred with local community communications. No unacceptable conditions were noted.

12. Heatup Phase Low Power Tests

The inspector reviewed test results and licensee evaluation of tests to verify that:

- -- Tests were conducted in accordance with Administrative Control Procedures;
- -- Test changes were identified and implemented without changing the basic objectives of the test in accordance with station procedures and Technical Specifications (TS);
- -- Test deficiencies and exceptions were identified, documented and reviewed;
- -- Deficiencies and exceptions were resolved, and retest requirements had been completed;
- -- Verification steps and data sheets of "As-Run" test procedures were properly initialed and dated;
- -- "As-Run" data were recorded, where required, within acceptance tolerances, and met acceptance criteria;
- -- Cognizant engineer evaluated test results and;
- -- Review of tests results were properly documented.

a. Low Power Average Range Monitor (APRM) Calibration

Low power APRM calibration was performed on September 18, 1982, using procedure ST12.1, Revision 0, March 29, 1982.

APRM adjustment factors were calibrated against Core Thermal Power (CTP), which was calculated from the core enthalpy balances.

The inspector verified that the adjusted final APRM readings were above zero and less than 0.5% power for all six channels, within tolerance for the heat balance of CTP of 0.573% (18.88 MWT).

No unacceptable conditions were identified.

b. Selected Control Rod Drive (CRD) Scram Time Test

The inspector reviewed scram time test data and selected recorder traces performed September 8, 1982. The test was conducted using procedure ST5.5 for selected B-2 sequence rods at 1.0% rated power, and the reactor pressure and core flow were 920 psig and 33.28 $x10^6$ lbm/hr. respectively.

The inspector verified that the test results were all within acceptance criteria, and no unacceptable conditions were identified.

c. Main Steam Isolation Valve (MSIV)

Procedure ST25.1, Revision 1, was used to perform MSIV closure time tests on September 21 - 23, 1982. The procedure requires that the time delay between the closure initiation signal and the extrapolated initial valve movement from 100% open position is equal to or less than 0.5 seconds. However, Appendix 25.1-A data sheet indicated that the delay time of MSIV 1F028B was 0.522 seconds, exceeding the acceptance criterion. Yet, "As-Run" procedural step 25.1.4.6 was signed off, indicating that all delay time measurements were within the acceptance criteria. No test exception report (TER) was issued.

The inspector expressed concern regarding this irregularity in data review. During subsequent discussion, the licensee acknowledged the concern, and TER No. 086 was issued on October 6, 1982 to repeat the delay time test. No unacceptable conditions were identified.

d. Plateau 2 Review

The inspector attended a portion of integrated technical review meeting for plateau 2, held on October 7, 1982. The following Startup Test Change Notices (STCN) and TER's were reviewed:

-- TCN Nos. 83, 84, and 118.

-- TER Nos. 30, 37, 43, 49, 56, 57, 71, 75-80, 86, and 119.

No unacceptable conditions were identified.

13. Licensee Events

a. Manual Scram on Loss of Control Rod Drive Pumps

At about 9:05 a.m. on September 16, 1982, the operators manually scrammed the Unit 1 reactor from less than 1% power during startup testing because both control rod drive (CRD) hydraulic supply pumps had tripped on low suction pressure. Conditions on the scram were normal. The cause of the low suction pressure trip of the CRD pumps was later determined to be cycling of a flow control valve in the condensate return line because of the relatively low condensate return flow. The CRD hydraulic pumps take a suction from this line. The problem was corrected by closing the valve at very low power operation.

b. Inadequate Pipe Support in Residual Heat Removal System

On October 6 the licensee reported a potentially defective pipe support in the RHR system. Because of concerns generated during the independent design review requested by NRR, the licensee re-examined 20 additional pipe supports and found 19 satisfactory. The other, an anchor for a 6 inch Residual Heat Removal System line, was found to have an inadequate weld (about one-third the specified length). The licensee initially concluded that this support would be overstressed by a factor of 4 under design conditions, that failure of the support would overstress a containment penetration, and that further pipe support adequacy assessment is needed before power operation above 5 percent is undertaken. The operating license limit is 5 percent until the NRC Commissioners approve higher power operation. At the licensee's request, further NRC Commissioner consideration of that authorization has been postponed.

The licensee will review an additional 3C0 as-built hanger design reconciliations to determine if inadequate engineering judgement was applied by Bechtel in accepting as-built conditions.

Further detailed analysis by Bechtel of the particular RHR anchor involved indicates that the as-built condition may have been acceptable, however such a determination would require more documentation than was originally provided. The licensee increased the length of the weld to ensure that the support would not be overstressed.

c. Low Water Level Scram

On September 20, 1982 the reactor tripped from four percent power on low reactor water level. The cause of the low level was due to the one operating feed pump ("C") tripping on low suction pressure. The low feed water suction pressure was caused by the on-service condensate demineralizer being isolated. A plant operator had just previously taken a demineralizer out-of-service, and put a new demineralizer on-service when the event occurred. Before the operators could get a reactor feed pump back on line the water level reached the scram set point (level 3). No ECCS systems were challenged. On October 4, the inspector reviewed circuitry drawings with the Plant Engineer responsible for determining why the demineralizer isolation valves had closed. The licensee had not concluded whether a logic problem existed in the condensate demineralizer isolation valves circuitry. The licensee's followup action to this trip will be reviewed during a subsequent inspection. (387/82-32-09)

14. HPCI Lube Oil Modification

The inspector reviewed the modification package for HPCI turbine lube oil piping changes completed on August 17, 1982.

The HPCI auxiliary oil pump (AOP) suction line was originally installed with 1½" pipe, which did not meet the design limit of the AOP suction vacuum. This was identified in Field Deviation Disposition Request (FDDR) KR1-213-0, July 10, 1980, and a subsequent FDDR Work Authorization was issued on August 11, 1982.

However, a non-Q listed 2" pipe was temporarily installed to replace the 1½" piping, as documented on Nonconformance Report 82-820.

A Work Authorization WA #5-25161 was issued on July 16, 1982, one day before the issuance of the Operating License (OL), to replace the non-Q listed piping with Q-listed, schedule #80, 2" pipe. The inspector further noted that the change package was neither reviewed by the Plant Operations Review Committee (PORC), immediately following plant turnover, nor subjected to the 10CFR50.59 review procedure. The work was completed on August 17, 1982.

The inspector determined that the engineering decision for the disposition of the NCR was performed prior to issuance of the Operating License and was therefore not subject to 10CFR50.59 requirements for the NCR. The inspector had a generic concern on PORC review of dispositions of NCR's which result in modifications to the plant. Nuclear Department Instruction (NDI)-QA-8.1.4 Revision 0, titled "Non-Conformance Control and Processing" discusses disposition requirements of NCR items, but does not require the disposition to be reviewed by PORC. The Operations Quality Assurance Supervisor stated that NCR's would be carefully screened to assure that the Technical Specification requirements were being met, and that any necessary changes to NDI-QA-8.1.4 would be completed by March 1, 1983. This item will be reviewed during a subsequent NRC inspection. (387/82-32-03)

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16. Exit Interviews

During the course of this inspection, meetings were held with facility management to discuss the inspection and findings identified. Those personnel attending these meetings are indicated in Section 1 of this report.