U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No. 50-334/86-20

Docket No. 50-334

Licensee: Duquesne Light Company
One Oxford Center
301 Grant Street
Pittsburgh, PA 15279

Facility Name: Beaver Valley Power Station, Unit 1

Location: Shippingport, Pennsylvania

Dates: August 28 - September 30, 1986

Inspectors: W. M. Troskoski, Senior Resident Inspector
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Approved by: J. E. Tripp 10/9/86
E. E. Tripp, Chief, Reactor Projects Section 3A Date

Inspection Summary: Inspection No. 50-334/86-20 on August 28 - September 30,1986

Areas Inspected: Routine inspections by the resident inspectors (131 hours) of licensee actions on previous inspection findings, plant operations, housekeeping, fire protection, radiological controls, physical security, surveillance testing, RCS flow setpoints, overpressure protection system, plant management changes and LER reviews.

Results: No violations were identified. Significant items reviewed included: a full power trip due to personnel error while testing the Solid State Protection System (Detail 4.b.1), equipment failure concerning the No. 3 inverter (Detail 4.b.2); concerns related to RCS flow measurement (Detail 6); and PORV stroke times inconsistent with those assumed in the safety analysis for a low temperature, overpressure type accident (Detail 7).

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DETAILS

1. Persons Contacted

During the report period, interviews and discussions were conducted with members of licensee management and staff as necessary to support inspection activities.

2. Plant Status

The plant completed its ascension to 100% power on September 3, 1986, and operated at full power throughout the inspection period with the exception of one trip (discussed in detail 4.b) on September 3, 1986. There was a planned shutdown period from September 12 - 14, 1986, to accomplish repairs in the main feedwater system (see detail 4.b), and a planned power reduction to 95% on October 1, 1986, to perform maintenance on a cooling tower pump.

On August 19, 1986, a reorganization of the DLC Nuclear Group was announced. Mr. J. J. Carey was elected to the position of Senior Vice President - Nuclear Group, with QA, Nuclear Operations and the BV-2 project groups reporting directly to him. Mr. J. D. Sieber was elected Vice-President of Nuclear Operations, with primary responsibility for Unit 1.

3. Followup on Outstanding Items

The NRC Outstanding Items (OI) List was reviewed with cognizant licensee personnel. Items selected by the inspector were subsequently reviewed through discussions with licensee personnel, documentation reviews and field inspection to determine whether licensee actions specified in the OIs had been satisfactorily completed. The overall status of previously identified inspection findings were reviewed, and planned and completed licensee actions were discussed for those items reported below:

(Open) Violation (86-11-02): Inadequate post-modification testing of Backup Indicating Panel (BIP) to assure it would perform its intended design functions. Specifically, a complete functional test was not performed on the RCS cold leg temperature indicators and therefore, did not identify that the instruments were wired incorrectly, and no test was conducted to ensure that the keys provided for the BIP locking transfer switches would work. Immediate corrective action consisted of making the necessary wiring changes on the temperature indicators and permanently attaching the correct keys for the BIP transfer switches to the Appendix R key rings. After these actions were complete, OST 1.45.9, BIP Instrumentation and Source Range Indication Test, was performed successfully. By letter dated August 8, 1986, the licensee stated that Nuclear Engineering and Construction Unit Management Procedure 2.7, Engineering Specifications, would be revised to clearly establish a minimum requirement for design change test specifications. This item remains open pending inspector review of Procedure 2.7.

(Open) Unresolved Item (85-11-01): Successful completion of OST 1.33.10, CO-2 Fire Protection System Test and licensee evaluation of current fire damper maintenance to determine need for a preventive maintenance program. The inspector reviewed the completed OST 1.33.10, which was performed on August 19, 1986. Partial performance of the OST was to verify damper actuation in the cable mezzanine and both EDG rooms. The test was satisfactory in that all dampers actuated as designated. However, this item will remain open pending licensee evaluation of the need for a fire damper preventive maintenance program. Further description of recent problems with fire damper operability is contained in NRC Inspection Report 334/86-15, detail 4.e.2.

(Closed) Inspector Follow Item (86-01-02): Revision of incorrect river water levels in TAB 23 of EPP Implementing Procedures. Earlier, the inspector had identified a discrepancy between the EPP/IP matrix and the corresponding TAB for classification of the emergency condition in the event of the Ohio River flooding. Revision 7 to the EPP/IPs has been issued and the inspector verified that the correct river water levels are contained in TAB 23.

(Closed) Violation (85-02-01): Completion of OST 1.11.16, Leakage Testing of RCS Pressure Isolation Valves, and licensee evaluation of questionable data gathered by OST 1.11.4, Accumulator Check Valve Testing. This item was last updated in NRC Inspection Report 334/86-07. OST 1.11.4 was previously performed on May 17, 1986, with questionable results. The licensee reperformed it on August 14, 1986. During this run of the test, the check valves on all three accumulators were found to have no leakage.

(Closed) IFI (86-04-04): Follow inspection and repair of steam generator safety valves that are showing signs of steam leakage. During the 5R outage, the licensee conducted mechanical maintenance on TV-MS-105A and B. After startup, the inspector observed the safety valve tail pipes and noted that the corrective maintenance efforts were effective in eliminating the leakage. This item is closed.

(Closed) IFI (86-04-03): Review balance of plant QC Program regarding prevention of foreign material addition at critical secondary system locations. The inspector was informed by the licensee that for critical secondary valves opened during the 5R outage, inspections were conducted both upstream and downstream to identify any potential loose parts. On all major valves in the Turbine Plant that were opened, a maintenance foreman performed loose parts searches before valve reassembly. The inspector determined that this practice should reduce the possibility of foreign material introduction. This item is closed.

(Closed) Violation (86-08-01): Failure to adhere to electrical separation criteria. A June 6, 1986, inspection found redundant chassis circuit cables located in the reactor trip breaker control wiring cubicles that were not separated by a fire retardant barrier or a maintained air space of 6". In the DLC August 27, 1986, response, the licensee committed to a 1" minimum separation that would be reflected in a future update to the BV-1 FSAR, Section 8.5.1. The basis for the 1" free air space was provided in "Test Report

on Electrical Separation Verification Testing for Duquesne Light Companies BVPS No. 2" which was reviewed and accepted by NRR Technical Reviewers (see NUREG-1057, SER for BV-2). The inspector had no further technical concern and this item is closed.

(Closed) Unresolved Item (85-06-05): Review licensee action to reduce backlog of mechanical MWRs. At Beaver Valley, MWRs are not used just to track deficiencies but also for accounting, budgetary and work control practices. The number of outstanding MWRs does not provide a true performance indicator as there is no segregation between nice-to-do items and station operability and priority items. Discussions with the Maintenance Supervisor indicated that most of the outstanding MWRs are not related to plant performance issues. Additionally, the station is currently moving to revamp the system to conform with INPO recommendations for tracking performance indicators. Since the licensee is in the process of revamping their system to provide more meaningful information, this open item serves no purpose and is therefore closed.

4. Plant Operations

a. General

Inspection tours of the plant areas listed below were conducted during both day and night shifts with respect to Technical Specification (TS) compliance, housekeeping and cleanliness, fire protection, radiation control, physical security and plant protection, operational and maintenance administrative controls.

-- Control Room
-- Primary Auxiliary Building
-- Turbine Building
-- Service Building
-- Main Intake Structure
-- Main Steam Valve Room
-- Purge Duct Room
-- East/West Cable Vaults
-- Emergency Diesel Generator Rooms
-- Containment Building
-- Penetration Areas
-- Safeguards Areas
-- Various Switchgear Rooms/Cable Spreading Room
-- Protected Areas

Acceptance criteria for the above areas included the following:

-- BVPS FSAR
-- Technical Specifications (TS)
-- BVPS Operating Manual (OM), Chapter 48, Conduct of Operations
-- OM 1.48.5, Section D, Jumpers and Lifted Leads
-- OM 1.48.6, Clearance Procedures
-- OM 1.48.8, Records

-- OM 1.48.9, Rules of Practice
-- OM Chapter 55A, Periodic Checks, Operating Surveillance Tests
-- BVPS Maintenance Manual (MM), Chapter 1, Conduct of Maintenance
-- BVPS Radcon Manual (RCM)
-- 10 CFR 50.54(k), Control Room Manning Requirements
-- BVPS Site/Station Administrative Procedures (SAP)
-- BVPS Physical Security Plan (PSP)
-- Inspector Judgement

b. Operations

Inspection tours of all accessible plant areas were conducted. During the course of the inspection, discussions were conducted with operators concerning knowledge of recent changes to procedures, facility configuration and plant conditions. The inspector verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. Except where noted below, the inspector comments or questions resulting from these daily reviews were acceptably resolved by licensee personnel.

(1) A reactor trip occurred from full power at 6:30 a.m. on September 3, 1986, due to personnel error during testing of the Train B solid state protection system in accordance with MSP 1.05. This MSP had been revised to include additional steps as a result of the shunt trip panel equipment installed per Design Change Package No. 622 "Automatic Actuation of the Reactor Trip Breaker Shunt Trip Coil." During one of these new procedure steps, the I&C technician incorrectly tripped the Train A reactor trip breaker by operating the shunt trip panel push button. A reactor trip occurred. It appears that the revised procedure was not clear to the I&C technician as a result of the added steps to accommodate the shunt trip panel equipment. The licensee plans to again revise MSP 1.05 to remove these added steps and to test the automatic feature of the shunt trip coil by a separate procedure. Review of licensee action to modify and clarify procedures to preclude recurrence is Unresolved Item (86-20-01). The reactor was restarted at about 7:00 p.m. on September 3, 1986, and taken to full power. The inspector observed the reactor and plant startup and no adverse conditions were noted.

(2) On September 5, 1986, at approximately 11:50 a.m., the inspector was in the control room and observed the actions of the operators in response to a loss of power to the No. 3 vital bus. Numerous annunciator alarms and indications occurred. The shift supervisor and the control room operators recognized almost immediately that the cause of the problem was the loss of the No. 3 vital bus inverter. It was confirmed later that the No. 3 inverter main power fuse had blown. The plant operator immediately switched the SG feedwater regulating valves from automatic to manual since the SG water level control signals are fed from No. 3 vital bus. A startup operator was directed to restore power to the No. 3 vital bus from

the auxiliary power source by placing the power transfer switch at the No. 3 vital bus distribution panel into the Auxiliary position. Power was restored in approximately one minute, and the SG feedwater regulating valves were returned to automatic. Other affected controls and alarms were reset and returned to normal. By 11:55 a.m., the plant was stable. A Unit Off Normal Report was issued to alert other operating personnel about the matter.

For the balance of the inspection period, the licensee powered the No. 3 vital bus from its auxiliary source. The licensee's efforts in determining the root cause of the problem with the No. 3 inverter were inconclusive. After replacing the blown power fuse for the inverter, a dummy electrical load was connected to it to check performance. No similar blown fuses occurred.

Problems with the blown power fuse for the No. 3 inverter have been reported in previous inspections (see detail 4.b(2) of Inspection Report 50-334/86-04). It was thought that the root cause of the inverter problem was a loose connection between the ground strap and the ground bus bar which was causing arcing. These loose connections had been tightened. However, now it appears that the root cause of the blown fuse problem with the No. 3 inverter is still unknown. Determination of the cause of this condition and licensee action to prevent recurrence is Unresolved Item (86-20-02).

At the end of the inspection period (September 30, 1986), the operation of the No. 4 inverter became suspect when it was reported that the "Phase Locked" indicating light on the front of the inverter panel intermittently flashed off and on. The licensee switched the No. 4 vital bus to its auxiliary power source and it remained in this condition until the end of the inspection period when it was returned to normal. Determination of the cause of the problem for the No. 4 inverter and the licensee's corrective action will be reviewed in a subsequent inspection.

The inspector was advised by the licensee that arrangements had been made with an equipment specialist to assist in solving the inverter problems. He was expected to be on site the week of October 6, 1986.

(3) A scheduled shutdown took place at 8:00 p.m., on September 12, 1986, to accomplish repairs in the feedwater system. The inspector observed the plant shutdown which occurred without incident. The major repair items were a leaking body-to-bonnet seal ring on the "A" feedwater isolation valve and a spring on the "B" feedwater regulating valve. These repairs were made as planned and the plant was brought back to power on September 14, 1986.

(4) While in the control room on September 25, 1986, the inspector observed the response of the operators to an anomaly in the Reactor Plant Component Cooling Water System (CCR System). At 8:26 a.m., the reactor operator acknowledged a CCR Pump discharge pressure low alarm. Simultaneously, it was noted that the CCR surge tank level rapidly decreased from 46" to 34". Operators immediately began to isolate CCR flow to all non-essential loads. CCR pressure and surge tank level stabilized. The operators then selectively unisolated individual loads to pinpoint the problem area. It was determined that the problem was due to a large flow of relatively cold coolant to the Boron Recovery System Evaporator Bottoms Cooler (1BR-E-3) which is a heat exchanger served by the CCR System. This large flow of relatively cold coolant occurred when 1BR-E-3 was started up after having been isolated, thereby quenching 1BR-E-3 and causing the transient in the CCR System (reduced pressure and surge tank level). The inspector observed the actions of the operators as they attempted to determine the cause of the anomaly. The operators used AOP-20 "Loss of CCR" and annunciator response for guidance during the transient. During this abnormal situation, operators were dispatched to the Auxiliary Building to check for leaks and to makeup the surge tank. Approximately 210 gallons were added to the surge tank. Normal conditions were established and the CCR System was considered stable at about 9:30 a.m. A Unit Off Normal Report was issued to alert other operating personnel.

c. Plant Security/Physical Protection

Implementation of the Physical Security Plan was observed in various plant areas with regard to the following:

-- Protected area barriers were not degraded;

-- Isolation zones were clear;

-- Persons and packages were checked prior to allowing entry into the Protected Area;

-- Vehicles were properly searched and vehicle access to the Protected Area was in accordance with approved procedures;

-- Security access controls to Vital Areas were being maintained and that persons in Vital Areas were properly authorized;

-- Security posts were adequately staffed and equipped, security personnel were alert and knowledgeable regarding position requirements, and that written procedures were available; and

-- Adequate lighting was maintained.

A bomb threat was received on September 5, 1986, at approximately 12:00 noon that affected Units 1 and 2. The Unit 2 switchboard operator received a telephone call stating that a bomb was planted in the fuel building. The caller did not indicate a specific time for detonation or which fuel building was involved. Unit 1 and 2 response team personnel immediately evacuated both fuel buildings and conducted searches. No bomb was found.

At about 8:20 a.m. on September 30, 1986, a security supervisor discovered a breach in the protected area fence where construction personnel were working in a pipe trench. The breach was large enough for an individual to crawl under the fence. The detection devices were inoperable at the time due to the work in the locality. The only compensatory measure available was a watchman stationed on the Unit 2 Control Room less than 100 yards away from the trench. The watchman had a clear view of the area and the trench was within his assigned section. According to the licensee, no one entered or egressed through the trench.

Construction personnel from Unit 2 had been working off and on in this trench for the past several days. When the work reached the protected area fence, a temporary metal plate (about 1,000 pounds which had to be installed and removed daily by use of a crane) was used. The construction forces were instructed to notify Security daily prior to start of work so that a permanent guard could be stationed in the area. This had been done for several days but it was neglected on September 30, 1986. The amount of time that the opening was unattended by Security personnel was estimated to be less than 25 minutes, since a Security Supervisor had inspected the site at 7:55 a.m. that morning.

The inspector discussed corrective actions with DLC Unit 2 personnel, S&W Project Management, and the Site Construction Manager. The inspector was informed that Site Directives would be issued to clearly require the presence of Unit 1 Security prior to the start of any work that could impact the integrity of the plant boundary. No such work would be allowed until a guard was posted. These actions appear acceptable, and the inspector had no further concerns.

d. Radiation Controls

Radiation controls, including posting of radiation areas, the conditions of step-off pads, disposal of protective clothing, completion of Radiation Work Permits, compliance with the conditions of the Radiation Work Permits, personnel monitoring devices being worn, cleanliness of work areas, radiation control job coverage, area monitor operability (portable and permanent), area monitor calibration and personnel frisking procedures were observed on a sampling basis.

No discrepancies were identified.

e. Plant Housekeeping and Fire Protection

Plant housekeeping conditions including general cleanliness conditions and control of material to prevent fire hazards were observed in various areas during plant tours. Maintenance of fire barriers, fire barrier penetrations, and verification of posted fire watches in these areas were also observed.

No discrepancies were identified.

5. Surveillance Testing

a. To ascertain that surveillance of safety-related systems or components is being conducted in accordance with license requirements, the inspector observed portions of selected tests to verify that:

(1) The surveillance test procedure conforms to technical specification requirements.

(2) Required administrative approvals and tagouts are obtained before initiating the test.

(3) Testing is being accomplished by qualified personnel in accordance with an approved test procedure.

(4) Required test instrumentation is calibrated.

(5) LCOs are met.

(6) The test data are accurate and complete. Selected test result data was independently reviewed to verify accuracy.

(7) The test provides for independent verification of system restoration.

(8) Test results meet technical specification requirements and test discrepancies are rectified.

(9) The surveillance test was completed at the required frequency.

The inspector observed portions of the following tests:

-- MSP 1.05 - Solid State Protection System, Train B, Functional Test.

-- OST 1.11.1 - Safety Injection Pump Test.

Comments pertinent to MSP 1.05 are included in detail 4.b.(1) of this report. The inspector identified no other concerns.

b. Review of Surveillance Testing for Rod Control and Rod Position Indication Systems.

The inspector conducted a review of the various operational surveillance tests (OSTs) conducted pertinent to the Rod Control and Rod Position Indication Systems. This review consisted of the inspector observing operator action in performing the OST in some cases and in reviewing the test results for all the listed OSTs. The inspector noted if the OST results met technical specification requirements. The following OSTs were included in this review and were performed satisfactorily:

-- OST 1.1.1 - Control Rod Assembly Partial Movement Test - This test was conducted satisfactorily on 4/21/86.

-- OST 1.1.13 - Channel Check of Group Demand Counters Within a Bank and Overlap Verification - This test was conducted satisfactorily on 5/17/86 and 8/26/86. It is required to be performed during startup and shutdown. The inspector observed the reactor operators performing this channel check during the reactor startup on 8/26/86.

-- OST 1.1.14 - Inter-Comparison Between Control Bank Benchboard Indicators and Logic Cabinet Indicator - This test was conducted satisfactorily on 8/24/86 in conjunction with Test Procedure BVT 1.6-2.2.1 "Initial Approach to Criticality after Refueling". The inspector observed the performance of this test by test personnel and operators as data was recorded from the group demand counters in the Control Room and from the indicators in the Rod Control System logic cabinet.

-- OST 1.1.15 - Operability Check of Group Demand Counters - This test was conducted satisfactorily on 8/14/86.

In addition to the above review of OSTs, the inspector discussed the results of the rod drop tests with licensee personnel. These tests were performed in accordance with BVT 1.1 - 1.1.1 in Mode 3 at normal operating temperature, pressure and flow prior to the initial reactor startup after refueling. The inspector observed the visicorder trace of one rod which was used to determine rod drop times. The drop out signal for the visicorder trace is taken from the stationary gripper coil voltage and the bottoming signal is taken as the point of dashpot entry. All drop out times were acceptable and were less than 2.0 seconds (Technical Specification value less than or equal to 2.2 seconds).

c. On September 25, 1986, at approximately 6:30 a.m., while in Mode 1, the licensee was conducting the scheduled monthly operational surveillance test (OST 1.13.1) on the 1A Quench Spray Pump (QS-P-1A). This test requires that the pump be run for at least 30 minutes. After approximately 7 minutes of operation, the pump automatically tripped due to an electrical overload condition. The licensee declared QS-P-1A inoperable which invokes the action statement of TS 3.6.2.1. This requires that

the pump be restored to operable status in 72 hours or to shutdown the reactor. The licensee suspected that the problem was a defective breaker. A Maintenance Work Request was written to replace the defective breaker with a spare breaker. This work was completed and OST 1.13.1 was then performed satisfactorily at approximately 12:40 p.m. on September 25, 1986. While performing OST 1.13.1, electricians monitored the running current at the breaker and the current values were considered normal. Vibration data recorded locally at the pump was also normal. Other data (e.g., pressure, flow) and information were reviewed and considered satisfactory and QS-P-1A was restored to an operable status at approximately 2:00 p.m. on September 25, 1986.

The inspector determined from the Director of Maintenance that bench testing of the defective breaker by maintenance personnel has produced similar unsatisfactory performance - i.e., the breaker initially closes but trips after about five minutes. The licensee has not yet isolated the defective part in the breaker, a GE Model AK-3A-25 600 V frame. Determination of the cause of this breaker problem will be reviewed in a subsequent inspection.

6. Reactor Coolant System Flow

The inspector reviewed Unit Off Normal Report 86-152 which was issued on September 17, 1986, to document an out-of-spec condition for the reactor trip setpoint of RCS flow transmitter FT-RC 414. This is one of three flow transmitters for the A Loop which are used for the two out of three logic to develop a reactor trip signal if RCS flow decreases below 90%. Technical Specification Table 2.2-1, Reactor Trip System Instrumentation Trip Setpoints, requires that loss of flow protection be provided by requiring this trip when flow decreases to 89% of the design flow per loop. A footnote defines the design flow as 88,500 gpm per loop (for a total flow of 265,500 gpm).

I&C became aware of the out-of-spec condition at 4:00 p.m. on September 17, 1986, after review of BVT 1.3 - 1.6.1, RCS Flow Measurement Test, performed on September 11, 1986. This BVT accumulated flow data for I&C even though it was unrelated to the test. This data (in the form of voltage readings) indicated that FT-RC 414 had a higher than previous 100% loop flow indication which when coupled with the existing trip setting produced an as-found reactor trip setpoint value of 87.5% flow. This is below the 89% allowable value limit specified in Table 2.2-1. The other two channels in the A Loop and all other channels for the B and C Loops were within specification. Upon identification of the problem, I&C notified the Shift Supervisor and placed the applicable channel in its tripped condition within one hour per TS 3.3.1.1.

MSP 6.03, F-414 Reactor Coolant Flow Loop 1 Protection Channel 1 Test, was modified to adjust the reactor trip setpoint based on the new value for 100% loop flow. The new setpoint was 3.377 plus or minus 0.020 vdc compared to the old setpoint which was 3.250 plus or minus 0.020 vdc. The channel was returned to service by 7:00 p.m. on September 17, 1986.

During review of BVT 1.3 - 1.6.1, the inspector identified several apparent anomalies. This procedure is run once per 18 months in accordance with TS 4.2.5.2, to verify that various DNB parameters are within the design envelope. Specifically, the reactor coolant system total flow rate for three-loop operation is required to be greater than or equal to 265,500 gpm with RCS T-average less than or equal to 581 F and pressurizer pressure at greater than or equal to 2,220 psia. The results of the test identified a total flow rate of 277,871 gpm. Though this was greater than the TS acceptance criteria, the inspector noted that both Loop A and Loop C had approximately 87,000 gpm each while Loop B had 103,000 gpm. The inspector questioned the magnitude of this discrepancy.

The loop flow rates were obtained by performing a primary plant calometric while at steady state full power conditions. The inspector noted that from the calometric data, Loop B T-Hot indicated about 604 to 605 F while the A Loop indicated about 613 F and the C Loop indicated 611 F. This test procedure did not specify acceptable ranges for the various parameters measured nor did it appear to account for instrument inaccuracies. Since both the core design document and Table 2.2-1 specify an RCS total flow rate of greater than or equal to 265,500 gpm, the inspector questioned whether or not the measurement uncertainty was built into this number or whether it was assumed that the various test procedures would account for them. Discussions with the Plant Manager and Plant Performance and Testing Engineers indicated that the licensee would: (1) determine whether or not an acceptance range should be specified for each RCS Loop when performing BVT 1.3-1.6.1, (2) determine whether the instrument inaccuracies were built into the design acceptance criteria or whether the procedure would have to be revised to include instrument uncertainties, (3) determine why the B Loop T-Hot value differed significantly from the other two loops. Licensee action in this regard will be followed as Unresolved Item (86-20-03).

7. Overpressure Protection System

Technical Specification 3.4.9.3 requires that overpressure protection be provided by two power operated relief valves (PORVs) with a nominal trip setpoint of less than or equal to 350 psig whenever the temperature of a non-isolated RCS cold leg is less than or equal to 275 F. The TS surveillance requirement only addresses stroking the operable PORV each time the plant enters Mode 5 (Cold Shutdown) unless tested within the preceding three months. OST 1.6.8, Placing Overpressure Protection Systems in Service, conducts that surveillance requirement verbatim.

The inspector reviewed NRR Safety Evaluation Report dated April 4, 1983. This SER analyzed two cases for this particular type of accident: (1) a mass input case and (2) a heat input case. The most restrictive PORV opening time was identified as the mass input accident which would require valve opening within 2.5 seconds. A review of MSP 6.68, Reactor Overpressure Protection PORV Setpoint Functional Tests, indicated that the nominal trip setpoint of less than or equal to 350 psig was addressed but the stroke time value was not. The inspector reviewed the Station's ASME Valve Stroke Log for PCV-RC-455C and

D (the two PORVs used to provide protection against exceeding the 10 CFR 50, Appendix G limit during periods of RCS water solid operation). The maximum stroke time specified per the ASME Code for 455 C was 3.8 seconds. During the last two years, the stroke time ranged from 2.0 to 2.8 seconds, just exceeding the SER assumptions. Valve 455 D had a maximum stroke time specified as 2.7 seconds by the ASME Code, though actual testing ranged from 1.8 to 2.5 seconds.

The inspector questioned why this assumption had not been included in either the TS or the Operating Surveillance Test. Discussions with licensee personnel indicated that appropriate revisions would be made prior to cooling down to 275 F. The licensee is currently evaluating this concern to determine whether the plant operated in an unanalyzed condition and potential reportability. Verification that the PORV stroke times are under 2.5 seconds during the next appropriate outage, will be followed as Unresolved Item (86-20-04). The inspector brought this TS deficiency to the attention of the Lead NRR Technical Reviewer as the Beaver Valley Technical Specifications were being used as the model for other plants.

8. Inoffice 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 action. 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 86-09, Failure to Perform Surveillance Test Within the Required Frequency.

LER 86-10, ESF Actuation

LER 86-11, Manual Reactor Trip When Four Control Rods Dropped.

LER 86-09 reported a missed ASME surveillance for the 1A fuel pool cooling pump, a non-technical specification system. Though it was performed within seven days of the plants return to normal operation (ASME XI - 1974 edition, Section IWP-3460(a)), it was outside the 1.25 limit of TS 4.0.5. The pump was operating throughout this time period and passed its subsequent surveillance test. The inspector determined that reporting this item was conservative. The Operations Supervisor indicated that the station still intends to keep all ASME components on a routine surveillance frequency throughout an outage when possible, and have all testing reinitiated prior to startup. The inspector had no further concerns.

LER 86-10 was discussed in detail 4.a.3 of Inspection Report 334/86-18. No further concerns were identified.

LER 86-11 was discussed in detail 4.a.5 of Inspection Report 334/86-18. No further concerns were identified.

9. Exit Interview

Meetings were held with senior facility management periodically during the course of this inspection to discuss the inspection scope and findings. A summary of inspection findings was further discussed with the licensee at the conclusion of the report period.