U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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Licensee:	Duquesne Light Company One Oxford Center 301 Grant Street Pittsburgh, PA 15279
Facility:	Beaver Valley Power Station, Units 1 and 2
Location:	Shippingport, Pennsylvania
Inspection Period:	July 18 - August 28, 1995
Inspectors:	Lawrence W. Rossbach, Senior Resident Inspector Peter P. Sena, Resident Inspector Scot A. Greenlee, Resident Inspector Lonny L. Eckert, Radiation Specialist

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for Reactor Projects Section 3B

Inspection Summary

This inspection report documents the safety inspections performed by resident inspectors in the areas of: plant operations; maintenance and surveillance; engineering; plant support; and safety assessment/quality verification. Additionally, an inspection conducted by a Region-based inspector is documented in the area of radiological controls. The results of these inspections are summarized in the executive summary.

EXECUTIVE SUMMARY

Beaver Valley Power Station
Report Nos. 50-334/95-13 & 50-412/95-13

Plant Operations

The licensee's aggressive pursuit of increased containment sump pump-out rate resulted in the identification of pressure boundary leakage at Unit 1. The plant shutdown was well controlled by the operating crews. Operator response to a Unit 2 trip was proper and no complications were noted. Good plant control and communications were demonstrated by crews from both units during the respective plant start-ups.

The licensee identified that reactor coolant pump seal injection flow exceeded technical specification limits after operators changed charging pump lineups at Unit 2. Operators had failed to perform a surveillance test to measure seal injection flow as specified by operating procedures. Following questioning by the inspectors, 16 additional instances were identified in which operators failed to perform the surveillance test after swapping charging pumps (since January 1995). Due to the multiple examples of failing to follow procedures and the initial limited scope of the licensee's review, this was cited as a violation.

Maintenance

Maintenance planning deficiencies were noted with the turbine driven auxiliary feedwater pump and emergency diesel generator governor. Specifically, the out-of-service time for the pump was not minimized, replacement parts were not adequately evaluated, and the work instructions for the diesel demonstrated a lack of technical understanding of governor electrical performance. Improvements were noted in reducing the out-of-service time during routine preventive maintenance activities for technical specification equipment; although additional improvements can still be obtained.

Excellent control of freeze seal activities was demonstrated during the repair of the Unit 1 pressure boundary leakage. Extensive troubleshooting activities were also noted in attempting to identify the cause of the loss of main generator field which resulted in the Unit 2 trip. An inspector follow-up item was opened involving the lack of documented technical justification for rescheduling of reactor coolant pump seal inspections.

Engineering

Overall, plant support by engineering personnel was good. Strong system engineer support of plant maintenance was noted during Unit 1 auxiliary feedwater and emergency diesel generator (EDG) maintenance activities. Some weaknesses were noted, however, in system engineer knowledge of EDG governor operation and testing. High quality engineering evaluations by the Nuclear Engineering Department (NED) included: (1) a basis for continued operation with seismic support deficiencies in the gaseous waste system; (2) review of a 10 CFR Part 21 Report from ABB concerning Type 51 and 87t relays; and (3)

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follow-up on the 21A recirculation spray pump performance problems. An inadequate NED technical evaluation report for piping improvements in the Unit 1 steam driven auxiliary feedwater pump oil system was noted.

A Nuclear Safety Department Technical Specification interpretation on required surveillance testing with an inoperable emergency diesel generator was found to be inadequate. The technical basis for the interpretation was satisfactory, but use of the interpretation would have violated Technical Specifications. The interpretation was subsequently voided.

Plant Support

Those portions of the licensee audits and appraisal, internal exposure control, contamination control, and the ALARA program reviewed by the inspector were determined to be were very good. The external exposure control program was assessed as good. The licensee self-identified that a two person work party entered an area posted as a high radiation area without the proper radiation monitoring device. This is being treated as a **non-cited violation** consistent with Section VII.B.1. of the Enforcement Policy.

The licensee's annual emergency preparedness exercise was conducted, with limited offsite participation, on July 26, 1995. Overall, exercise performance was good and demonstrated that the licensee was able to implement the Emergency Plan to protect the health and safety of the public. No exercise strengths were identified. Technical Support Center involvement in evaluating conditions that place the plant outside of the emergency operating procedures was identified as an area for improvement. Two exercise weaknesses were identified: (1) Due to misinterpretation of an emergency action level criterion, a Site Area Emergency (SAE) was declared prior to meeting all the criteria for the declaration. (2) The Pennsylvania Emergency Management Agency was not informed of the SAE until 1 hour and 20 minutes after the declaration. The licensee's self-evaluation following the exercise was very good.

Safety Assessment and Quality Verification

Overall, the licensee's corrective actions for several plant issues (primarily reportable events) were found adequate, but several weaknesses were noted in the licensee's corrective actions system (Problem Report System). Noted deficiencies included: (1) a root cause analysis that identified a procedural violation as an isolated occurrence, vice a frequent problem that occurred 17 times in the last 7 months; (2) weak, incomplete or overdue documentation in the problem report files; and (3) one instance where the licensee was slow to evaluate the existence of similar problems elsewhere in the plant. The licensee is evaluating improvements to the Problem Report System.

The Operations Department demonstrated a very good safety perspective by aggressive pursuit of the increase in the Unit 1 containment pump-out rate. Additionally, the Operations Department completed a very high quality self-assessment involving the return of technical specification equipment to

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service following routine preventive/elective maintenance. The conclusions of the assessment were the same as those reached by the NRC during a similar evaluation.

The quarterly Offsite Review Committee (ORC) meeting and two ORC subcommittee meetings were effective in the evaluation and review of plant activities. All three meetings were chaired by a consultant - a recent improvement. Of particular note were the contributions and insights gained from the consultants.

Quality assurance (QA) personnel were more actively involved in assessing plant startup activities than in the past. Review of operating logs by the QA staff showed that plant operators missed a surveillance requirement to manually calculate a quadrant power tilt ratio. This finding was indicative of a thorough review.

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DETAILS

1.0 MAJOR FACILITY ACTIVITIES

With the exception of two minor power reductions (no more than 2%), Unit 1 operated at 100% power from July 17 to August 17. One of the power reductions was initiated when condenser vacuum started dropping following failure of the auxiliary steam pressure controller on August 17. The other power reduction was to maintain satisfactory main condenser hotwell conditions during a period of high ambient temperature and humidity. On August 18, the licensee identified a reactor coolant system pressure boundary leak at Unit 1 and commenced a plant shutdown. Unit 1 entered Mode 5 (cold shutdown) on August 20 and remained in Mode 5 until August 25 when plant heatup began. Unit 1 was synchronized to the grid on August 27 and returned to 100% power on August 28.

With the exception of minor power reductions needed to maintain main condenser hotwell conditions, Unit 2 operated at 100% power from July 17 to August 13. On August 13, a reactor trip occurred from 100% power. Plant restart was commenced on August 14, and the unit was synchronized to the grid on August 15. The unit remained at 100% power for the remainder of the inspection period.

2.0 PLANT OPERATIONS (71707)

2.1 Operational Safety Verification

Using applicable drawings and check-off lists, the inspectors independently verified safety system operability by performing control panel and field walkdowns of the following systems: Unit 1 emergency diesel generator air and Unit 2 emergency diesel generator; quench spray; safety injection; and auxiliary feedwater. These systems were properly aligned. The inspectors observed plant operation and verified that the plant was operated safely and in accordance with licensee procedures and regulatory requirements. Regular tours were conducted of the following plant areas:

- Control Room
- Auxiliary Buildings
- Switchgear Areas
- Access Control Points
- Protected Areas
- Spent Fuel Buildings
- Diesel Generator Buildings
- Safeguards Areas
- Service Buildings
- Turbine Buildings
- Intake Structure
- Yard Areas
- Containment Penetration Areas
- Unit 1 Containment

During the course of the inspection, discussions were conducted with operators concerning knowledge of recent changes to procedures, facility configuration, and plant conditions. The inspectors verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. The inspectors found that control room access was properly controlled and a professional atmosphere was maintained. Inspectors' comments or questions resulting from these reviews were resolved by licensee personnel.

Control room instruments and plant computer indications were observed for correlation between channels and for conformance with technical specification (TS) requirements. Operability of engineered safety features, other safety related systems, and onsite and offsite power sources were verified. Due to the hot summer weather, the inspectors frequently monitored the ultimate heat sink (river water) temperature and verified that operation remained within the design basis. The inspectors observed various alarm conditions and confirmed that operator response was in accordance with plant operating procedures. Compliance with TSs and implementation of appropriate action statements for equipment out of service were inspected. Logs and records were reviewed to determine if entries were accurate and identified equipment status or deficiencies. These records included operating logs, turnover sheets, system safety tags, and the jumper and lifted lead book. The inspectors also examined the condition of various fire protection, meteorological, and seismic monitoring systems.

2.2 Unit 1 Shutdown Due to Reactor Coolant System Pressure Boundary Leakage

On August 18, 1995, a containment entry was made to identify the source of increased containment sump pump-out rate (about 8 gph). Chemistry results identified that the sump water contained 300 ppm boron and isotopes of xenon and iodine. A reactor coolant system water inventory balance (OST 1.6.2) calculated an unidentified leakage rate of 0.12 gpm. At 8:35 p.m., a reactor coolant system leak was identified at a socket weld of 1CHS-340. This valve is the first high point vent from the 'A' reactor coolant pump number one seal bypass line. The seal bypass line is normally not in service but does tap off the high pressure side of the number one seal, and is thus subject to full reactor coolant system pressure. Thus this leak was considered pressure boundary leakage. Per technical specification 3.4.6.2, the plant must be in hot standby within the next 6 hours if any pressure boundary leakage exists. In accordance with the licensee's emergency action levels, an Unusual Event was appropriately not declared since the pressure boundary leakage did not exceed 10 gpm. The inspectors observed the plant and reactor shutdown and noted very good communications and teamwork among the operating crew. The entire evolution was completed in a controlled and deliberate manner with very good involvement and oversight by the shift supervisors. The inspectors concluded that the licensee demonstrated a very good safety perspective by aggressively pursuing the increase in containment pump-out rate.

2.3 Unit 1 Plant Heatup and Startup

Unit 1 was in Mode 5 (cold shutdown) from August 20-25, 1995, following a plant shutdown to repair a defective reactor coolant pressure boundary weld. Additional significant maintenance items completed in Mode 5 included permanent repair of two leaking secondary side steam generator manways, permanent repair of an ASME Code Class 2 main steam drain line (the temporary repair was discussed in Section 3.1.4 of NRC Inspection Report 50-334/95-09) and replacement of the governor on the No. 1 emergency diesel generator. Unit 1 plant heatup following the mini-outage began on August 25. The unit was ultimately taken critical and synchronized to the grid on August 27. The Unit returned to 100% power on August 28.

The inspectors independently reviewed the technical specification prerequisites for the mode changes from cold shutdown conditions to power operations. All mode change requirements were satisfied. The inspectors also observed plant heatup, synchronization to the grid and power escalation. Overall, the licensee demonstrated good plant control and communications. Of particular note was the excellent coordination between the reactor operator, the plant operator and the steam generator level control operator during low power changes in steam demand.

The inspectors also observed that quality assurance (QA) personnel were in the control room observing plant startup activities. The QA observers were not restricted to the back of the control room (as noted during a previous Unit 2 startup), and appeared to be more actively involved in assessing plant activities than in the past.

2.4 Unit 2 Seal Injection Flow

On July 25, 1995, the shift supervisor identified that the total seal injection flow to the reactor coolant pumps had exceeded the technical specification maximum. Actual seal injection flow was 29.3 gpm while technical specification 3.5.4 establishes a limit of 28 gpm. The basis for this limit is that seal injection flow is considered a net loss from the safety injection flow to the reactor coolant system.

The inspectors performed an independent review of this event, in parallel with that performed by the operations experience group, in order to determine the root cause. On July 23, operators had started charging pump 2CHS-P21A and secured charging pump 2CHS-P21C per operating procedure 2OM 7.4.A, "Placing a Charging Pump in Standby or Inservice." At the same time, calibration procedure 2LCP-6-T408A-I was in progress, which required manual pressurizer level control. After swapping the pump alignment, the operator adjusted the charging pump return flow control valve 2CHS-FCV-122 and was satisfied with seal injection flow rates. However, the operator did not complete operational surveillance test 2OST-6.4, "Measurement of Seal Injection Flow," as specified by Step 16 of 2OM 7.4.A. This OST obtains the total seal injection flow at normal operating pressure when the seal injection flow control valve is fully open. It is necessary to perform this OST after swapping charging pumps because each charging pump has a different discharge head. The inspectors agreed with the results of the licensee's TapRooT investigation which concluded: (1) procedure 2OM 7.4.A was followed incorrectly; (2) a complex system existed (operators were monitoring greater than three items at once) and; (3) enforcement of the performance of 2OST-6.4 was inadequate as shift supervision failed to ensure its completion.

The inspectors, however, also identified that the failure to perform 2OST-6.4 after swapping charging pumps was not isolated to this single occurrence. The inspectors reviewed the operating logs and completed surveillance tests for the months of June and July. Two additional occurrences (June 9 and July 15) were identified in which charging pumps were swapped, but the seal injection OST was not completed. This indicated to the inspectors that the failure to properly follow procedures was more widespread than the single incident of July 25. The inspectors raised these occurrences to the attention of

Operations management to ensure the licensee's corrective actions considered the broader scope of the problem. Subsequent additional investigation by the licensee revealed a total of 17 occasions since January 1995 in which the seal injection flow OST was not performed following charging pump swaps. Only one additional occasion resulted in exceeding 28 gpm seal injection flow for 19 hours on March 22. The inspectors also reviewed Unit 1 logs and noted that this same problem has not occurred. The Unit 1 procedure for swapping charging pumps has a procedural signoff that requires shift supervision to verify completion of the seal injection flow OST.

There was minimal safety significance in exceeding the technical specification seal injection limit, as the licensee's engineering department verified that design basis requirements for total safety injection flow would have been satisfied. However, the identification by the inspectors of additional incidents in which the OST was not completed, highlights the need for thorough root cause analyses so that proper corrective actions can be taken to address the root cause. Due to the multiple examples of this failure to follow procedures and the initial limited scope of the licensee's review, the failure to satisfy technical specifications will be cited as a **violation (50-412/95-13-01)**.

2.5 Unit 2 Reactor Trip and Plant Recovery

On August 13, 1995, Unit 2 experienced a reactor trip from 100% power. A review of the sequence of events recorder indicated that a loss of main generator field occurred which resulted in a main generator/turbine trip, followed by a reactor trip. The inspectors interviewed the operators who responded to the transient and determined that all appropriate actions were taken per the emergency operating procedures. A review of the sequence of events recorder and post-trip plant parameters indicated that plant response was normal, and no significant complications resulted. The inspectors did note that the post-trip review, per Nuclear Power Administrative Procedure 5.2, specifies only a minimal number of post trip plant parameters to review (such as reactor trip breaker timing, reactor coolant temperature, pressurizer level and pressure and steam generator level). The "historical data storage and retrieval" printout contains other information which is also valuable to examine. For example, the inspectors reviewed code safety tailpipe temperature and pressurizer relief tank temperature and level since minor leak-by of the 'B' pressurizer code safety existed prior to the trip. The inspectors questioned the shift technical advisors and noted that additional parameters were also being reviewed depending on the knowledge level of the reviewer.

The licensee was able to confirm, via three independent relay protection schemes, that an actual loss of field did occur. Investigation on the cause of the undervoltage condition, with assistance from Westinghouse, consisted of preventive maintenance checks of the voltage regulator, exciter field circuit breaker, and meggering of the exciter field and permanent magnet generator (PMG). No conclusive deficiency was identified. Electricians did, however, identify a potential ground point on the AC output of the voltage regulator in that a bracket on the current limiting resistor was loose and in contact with the base plate. A second ground point was not found. But if a second intermittent point did exist, this would have resulted in a loss of field.

On August 14, a reactor startup was conducted. The inspectors observed the approach to criticality and turbine startup and noted that all activities were conducted in a safe and deliberate manner. The voltage regulator, PMG output, field voltage and current, and protection relays were instrumented for enhanced monitoring during turbine roll and unit synchronization. No abnormalities were identified by the licensee or Westinghouse. As a prudent measure, the licensee also completed the preventive maintenance inspection of the Unit 1 voltage regulator and removed the same brackets. Overall, the startup activities by operators ensured a proper level of safety was maintained and troubleshooting by maintenance and engineering personnel was thorough in attempting to identify the root cause of the trip.

3.0 MAINTENANCE (62703, 61726, 71707)

3.1 Maintenance Observations

The inspectors reviewed selected maintenance activities to assure that: the activity did not violate Technical Specification Limiting Conditions for Operation and that redundant components were operable; required approvals and releases had been obtained prior to commencing work; procedures used for the task were adequate and work was within the skills of the trade; activities were accomplished by qualified personnel; radiological and fire prevention controls were adequate and implemented; QC hold points were established where required and observed; and equipment was properly tested and returned to service.

The maintenance work requests (MWRs), preventive maintenance procedures (PMPs), and corrective maintenance procedures (CMPs) listed below were observed and reviewed. Unless otherwise indicated, the activities observed and reviewed were properly conducted.

MWRs:

042185	Terry Turbine Governor Valve Linkage Evaluation (see Section 3.1.1)
043752	Turbine Driven Auxiliary Feedwater Pump Oil System Sight Glass Installation (see Section 3.1.1)
044300; 044303	Investigate Operation of Dampers 2HVS*MOD210B and 211B at Degraded Voltage
045086; 044723	Inspection of Unit 1 and Unit 2 Voltage Regulators (1/2PMP-35-Exc-Regulator-1E)
045006	Loop 3 Cold Leg RTD Calibration

045047 Replace Number 1-1 Emergency Diesel Generator Governor (see Section 3.1.2)

PMPs:

24FW-T-2/22 Turbine Auxiliary Feed Pump Linkage, Governor Valve and Turbine Maintenance (see Section 3.1.1)

CMPs:

75-FREEZE-SEAL Freeze Sealing of Piping

This procedure was used to establish a freeze seal on the 1A reactor coolant pump seal bypass line in order to repair a socket weld on an associated vent line. The procedure and its implementation were evaluated against NRC Inspection Manual Part 9900 technical guidance. The inspectors concluded that the procedure was well written with appropriate guidance. The licensee used a contractor with expertise in freeze seals to conduct the freeze seal operations. The contingency plans established for a loss of the freeze seal included an engineered pipe plug and operating crew briefings on the use of the reactor coolant loop isolation valves. The inspectors concluded that the licensee demonstrated excellent control over the freeze seal operations.

3.1.1 Unit 1 Turbine Driven Auxiliary Feedwater Pump Maintenance

On August 1, 1995, the inspectors observed three maintenance items on the Unit 1 turbine driven auxiliary feedwater pump. The three items involved: (1) checking the torque required to move the governor stem, and verification of the amount of stem travel (MWR 042185); (2) periodic inspection and lubrication of the governor valve, trip throttle valve and overspeed trip mechanism (1/2PMP-24FW-T-2/22-1M); and (3) installation of a design equivalent change that added a sight glass on the suction side of the integral oil pump (MWR 043752). The inspectors noted very good involvement by the System Engineer with performance of the maintenance activities. However, three problems with these activities were noted: (1) The maintenance planning process did not support minimizing the pump out-of-service time. The pump was out-of-service for approximately 6 hours prior to the start of maintenance. This time could have been reduced through better coordination of clearance activities and the pre-staging of tools and replacement parts. (2) The wrong revision of the technical evaluation report (TER) for the sight glass installation was in the work package. (3) The parts procured for the site glass installation were not adequately evaluated by the TER. A piping cross was intended as a replacement for a piping tee, but the cross was too big to fit in the tee location, and the weight of the cross was significantly greater than the value used in the seismic stress evaluation.

The maintenance planning observations were discussed with licensee management. The inspectors were informed that efforts were in progress to formalize a process to ensure minimum outage time for on-line maintenance of critical safety equipment. A problem report was initiated to document the TER revision discrepancy and the inadequacies associated with the TER. Additionally, licensee management directed a formal root cause evaluation of the TER inadequacies. The inspectors concluded that these actions were appropriate.

3.1.2 Unit 1 Emergency Diesel Generator Governor Replacement

On August 16, 1995, during the monthly surveillance test, the No. 1-1 emergency diesel generator (EDG) would not maintain steady load while paralleled to the grid. The licensee evaluated this problem, and through discussions with the EDG vendor, determined that the diesel was still operable. The licensee's basis for continued operation (BCO) evaluation stated that the condition indicated a possible minor internal hydraulic leak that would not effect emergency mode operations. The inspector reviewed BCO and determined that the licensee's evaluation was sound. EDG load drift during parallel mode operations is expected with minor governor internal oil leakage; however, minor governor oil leakage would not be evident during the isosynchronous (emergency) mode of operation. The evaluation also recommended replacement of the governor at the earliest opportunity. The licensee originally planned to replace the governor at power sometime during the following three weeks. Actual replacement appropriately occurred the following week when Unit 1 entered Mode 5 for an unscheduled outage.

The inspectors observed the governor replacement and testing activities. A vendor representative was present during all of these activities, and the activities were coordinated by the EDG System Engineer. During review of the maintenance work instructions, the inspectors noticed that the licensee intended to load the EDG, in parallel with the grid, with zero speed droop set into the governor. This would have presented a potentially unstable condition since the EDG would have attempted to rapidly achieve full load as soon as the generator output breaker was shut. The observation was discussed with the maintenance foreman and the vendor representative. The work instructions were subsequently changed to prevent parallel operations without speed droop. The inspectors also noticed that the work instructions did not include an evaluation of the proper setting of governor speed droop. This was discussed with the System Engineer who subsequently contacted the vendor for advice. The vendor explained how to evaluate the speed droop setting and also noted that the governor was delivered with a mark to indicate the recommended speed droop setting. The licensee's original plans were to set the speed droop at the same setting indicated on the old governor. The work instructions were changed to verify optimal governor speed droop.

The inspectors concluded that the licensee's maintenance work instructions demonstrated some lack of understanding of the emergency diesel generator governor as it relates to electrical performance. Ultimately, the licensee did demonstrate that the new governor would perform adequately under design basis conditions. The licensee plans to incorporate the lessons learned from this maintenance into a formal governor maintenance procedure. This should prevent the problems noted by the inspectors.

3.1.3 Return of Equipment to Operable Status

The inspectors performed a follow-up inspection involving the removal and return of technical specification equipment to service following routine preventive/elective maintenance. A past instance was previously identified in which maintenance was untimely in returning the equipment to Operations for operability testing (see NRC Inspection Report 50-412/94-28). The inspector specifically tracked the times the equipment was removed from service, maintenance initiated and completed, and operability test commenced and completed. The specific equipment monitored by the inspectors included the motor driven auxiliary feedwater pump (FW-P-23B), quench spray chemical injection pumps (2QSS-P-24A and B), and the supplemental leak collection and release system (2HVS-MOD-210B/211B). In each of these instances, electrical and mechanical maintenance personnel commenced and completed the work in a timely manner, such that the equipment was returned to operations for post-maintenance testing within an appropriate time period. This allowed the daylight operations shift to test the equipment for operability before turnover occurs with the afternoon shift (which would subsequently delay the testing by about 2 hours). One clearance (for 2QSS-P24A) was, however, posted about 90 minutes earlier than necessary and resulted in additional technical specification action time. This same observation was noted for the Unit 1 auxiliary feedwater pump (see Section 3.1.1) in which the clearance was posted about an hour earlier than necessary.

The Operations Department also completed a similar self assessment. The inspector reviewed this assessment and found it to be of very high quality. The same conclusions were reached by the licensee and inspectors. Overall, operations and maintenance personnel are demonstrating proper sensitivity towards technical specification action times. Also, the technical specification action time has been reduced from previous occasions involving preventive maintenance, but improvements can still be obtained.

3.1.4 Reactor Coolant Pump Seal Preventive Maintenance

Per the licensee's "Individual Plant Examination" for both units, a large fraction (about 50%) of the core damage frequency is associated with a reactor coolant pump seal loss of coolant accident. A large fraction of these events are caused by station blackout and loss of switchgear ventilation. During a review of rescheduled maintenance activities for Unit 2, the inspectors noted that the licensee's preventive maintenance of reactor coolant pump seals was not consistent with the vendor recommendations. Specifically, Westinghouse suggests performing seal inspections (number 1, 2 and 3 seals) at a frequency of every 16,000 hours of operation (about every 2 years). To satisfy this frequency, a three-loop plant such as Beaver Valley would have to perform a seal inspection of two reactor coolant pumps every other refueling outage. Instead, both Beaver Valley units perform only one reactor coolant pump seal inspection every refueling outage. Thus, the time between seal inspections for the same reactor coolant pump is 54 months (assuming a 18-month fuel cycle). For example, the 21A reactor coolant pump seals were last inspected during the third refueling outage in April 1992 and will next be re-inspected during the upcoming sixth refueling outage in September 1996. Westinghouse has not endorsed this change in inspection frequency. The licensee did not have a documented technical justification for the deviation from the vendor guidance. Per the licensee's preventive maintenance program, the Manager of Maintenance or the Manager of Maintenance Assessment and Engineering must authorize the rescheduling of preventive maintenance tasks. The inspectors questioned licensee personnel on the technical basis for the extension of the vendor recommended frequency and were provided the Westinghouse field reports. These reports consistently indicate that the number 1, 2 and 3 seal runners and rings have been found in a good condition, and that the height of the graphitar nose for the number 2 and 3 seals have been acceptable for reuse until the next planned inspection. The only common deficiency has been fretting on the number 1 seal insert (which is changed out every inspection). The inspector did not identify any notable deficiencies in these field reports. However, this issue shall remain open for additional inspection pending completion of a documented evaluation by the licensee (IFI 334/412-95-13-02).

3.2 Surveillance Observations

The inspectors witnessed/reviewed selected surveillance tests to determine whether properly approved procedures were in use, details were adequate, test instrumentation was properly calibrated and used, technical specifications were satisfied, testing was performed by qualified personnel, and test results satisfied acceptance criteria or were properly dispositioned. The operational surveillance tests (OSTs) listed below were observed and reviewed. Unless otherwise indicated, the activities observed and reviewed were properly conducted without any notable deficiencies.

1OST-1.7 Manual Reactor Trip Test

The inspectors noted very good coordination, communications and self checking during this surveillance test.

1OST-26.4 Main Turbine Pedestal Checks

The inspectors noted very good coordination and communications and excellent self checking during this surveillance test.

2OST-15.1 Primary Component Cooling Water Pump (2CCP-P21A) Test

This surveillance test was the first pump run conducted following the replacement of the rotating element. Accordingly, the operating crew treated this test as a high risk evolution. The system was twice verified as being properly filled and vented prior to the pump start. After a 1 second pump bump to verify proper rotation, the system was again verified as being properly filled and vented. During the actual pump run, operators properly monitored bearing temperatures on the plant computer with a 5 second scan interval. Operators were also sensitive to component cooling water system parameters (such as flow to the reactor coolant pump stator) during throttling evolutions. Overall, operators applied lessons learned from past events in which pumps were significantly damaged during post maintenance testing.

4.0 ENGINEERING (37551, 71707, 90712, 92700)

4.1 Review of Written Reports

The inspectors reviewed Licensee Event Reports (LERs) and other reports submitted to the NRC to verify that the details of the events were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspectors determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted further onsite follow-up. The following LERs were reviewed:

<u>Unit 1</u>:

94-09 Condition Prohibited by Technical Specifications-Inadequate Reactor Coolant System Relief Path (see Section 6.1)

94-10 Condition Prohibited by Technical Specifications-Low Air Pressure in the Control Room Ventilation Damper Seals (see Section 6.1)

95-01 Condition Prohibited by Technical Specifications-Containment Ventilation Flow Exceeded Refueling Limit (see Section 6.1)

95-02 Condition Prohibited by Technical Specifications-Safety Related 480 Volt Bus Found Seismically Unqualified (see Section 6.1)

<u>Unit 2</u>:

95-02 Entry into Technical Specification 3.0.3 Due to Isolation of Control Room Habitability Air Bottle Subsystem

This event involved a discharge of bottled air into the control room. The cause was the inadvertent electrical shorting across adjacent terminal screws while installing a test jumper. The inspectors interviewed the operators involved and noted that proper self-checking techniques were being applied. The root cause was determined to involve "man-machine interface" and a cramped work environment. As corrective action, terminal strip banana jack adapters are being installed which would reduce the probability of contacting adjacent terminals during such testing. The inspectors concluded that the licensee effectively identified and evaluated the root cause and that the corrective actions are appropriate.

95-03 Train 'B' Recirculation Spray System Header Cooling Flow Below Technical Specification Requirements

This issue was inspected separately as documented in NRC Inspection Report 95-80. The inspectors independently reviewed the containment analysis calculations which demonstrated that the recirculation spray system still would have met its design basis requirements. Specifically, following a design basis event, the quench spray/recirculation spray systems must be able to return the containment to a subatmospheric condition within 3600 seconds and subsequently be able to maintain subatmospheric conditions. The containment analysis was completed using an actual peak river water temperature of 82°F and assumed 200 tubes plugged (vice 55 actual). A second analysis was also completed using a design basis river water temperature of 89°F and actual tubes plugged. In both of these cases, the acceptance criteria was satisfied. Thus the safety significance of the reduced service water flow to the 'B' train recirculation spray heat exchangers was minimal. This LER is closed.

95-04 Technical Specification Violation Involving High Seal Injection Flow.

This event is discussed in Section 2.4.

The above LERs were reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. Generally, the LERs were found to be of high quality with good documentation of event analyses, root cause determinations, and corrective actions. These event reports are closed based on in-office review of the event report and onsite inspections.

4.2 Basis for Continued Operation Evaluations

The basis for continued operation (BCO) evaluations listed below were reviewed for technical adequacy and for compliance with regulatory requirements. No problems were identified during the review of these evaluations. Overall, the evaluations were of high quality and had sufficient documentation to justify continued operation with the identified condition.

1-95-005 Seismic Support Deficiencies Associated with Gaseous Waste System Rupture Disks (see Section 6.1)

1-95-007 No. 1 Emergency Diesel Generator Load Drift in Parallel with the Grid (see Section 3.1.2)

4.3 Protective Relay 10 CFR 21 Report

On July 19, ABB Power T & D Company issued a 10 CFR 21 Report involving a potential problem with type 51 and 87t relays. The specific problem involved a defective tap block which is used to select or change the relay current setting. The potential exists for the tap block to open circuit the transformer current when the tap pin is removed. A large voltage potential is possible when the current transformers are open circuited, thus creating a hazard to the technicians. These relays are installed for the motors of the Unit 2 reactor coolant pumps, cooling tower pumps, condensate pumps, and main feed pumps. The licensee has reviewed the applicable information and determined that the relays remain functional and the operability of the pumps is not affected. Also, the licensee's relay calibration procedure which changes the tap setting is only accomplished with the relays de-energized; thus, the personnel hazard would not present itself. The licensee has tested the spare relays in stock and no problem was identified. The licensee plans on testing the installed relays during the next scheduled calibration. The inspector reviewed the 10 CFR 21 report and the licensee's evaluation and did not find a need for a "basis for continued operation." The inspector also noted the relays were not installed in Quality Assurance Category I equipment (safety related); thus, the 10 CFR 21 report was not applicable.

4.4 Unit 2 Recirculation Spray Pump Performance

During the last Unit 2 refueling outage, the licensee overhauled the 21A recirculation spray pump and installed new first and second stage impellers. However, pump performance was virtually unchanged (see NRC inspection report

50-412/95-07) from its pre-overhaul condition. A technical specification amendment was subsequently submitted and approved to allow operation with the post-overhaul flow and head performance. The licensee has completed a follow-up investigation and determined that the vendor (Sulzer Bingham Pumps) provided the licensee with impellers machined with incorrect vane profiles. The backside diameter and vane angle of the impellers was consistent with the certified performance curves from the factory; however, the underfile and overfile dimensions to which the impellers were machined, were not consistent with the hydraulic requirements. Too much material had been removed from the sides of the suction and discharge vanes for both impellers. The overfile and underfile specifications were considered proprietary by the vendor and not provided to the licensee. A vendor representative was present during the receipt inspection and pump overhaul, but did not identify this deficiency. The licensee is currently evaluating any necessary corrective actions. Current pump performance is acceptable, based on the new technical specifications. The inspector reviewed the information provided by the pump vendor and noted the licensee's conclusions were correct. Additionally, the inspector considered the responsible engineer to be tenacious in completing the follow-up investigation and addressing why pump performance did not improve as expected.

4.5 Unit 2 Technical Specification Interpretation

During the Unit 2 shift brief on July 19, the inspectors learned that the licensee was implementing an interpretation of Technical Specification 3.8.1.1. The interpretation would allow one emergency diesel generator (EDG) to be taken out of service for planned maintenance or testing without testing the other EDG. The inspectors pointed out that while this interpretation is consistent with standard Technical Specifications, the licensee's plant specific Technical Specification clearly states that the redundant EDG is to be tested if one EDG is inoperable. The licensee promptly withdrew the interpretation. A Technical Specification amendment has been submitted to adopt the standard Technical Specification.

5.0 PLANT SUPPORT (71750)

5.1 Radiation Protection Program - Occupational Exposure Controls During Cyclic Operations

A review of the licensee's radiological controls program during cyclic operations at both units was conducted. The review included: audits and appraisals; changes; training and qualifications; external exposure control; internal exposure control; maintaining radiation exposures as low as is reasonably achievable (ALARA); and contamination controls.

5.1.1 Audits and Appraisals

The inspector reviewed the status of the health physics surveillance reporting program (called Health Physics Surveillance Reports by the licensee) as a follow-up to NRC Combined Inspection 50-344/94-81 and 50-412/94-81. The inspector concluded that a formal causal coding system had been established and that the program was up-to-date with all July 1995 findings entered into the system.

The inspector reviewed Problem Reports (the station discrepancy resolution system) which had been generated by the licensee since January 1, 1995, as a follow-up to NRC Combined Inspection 50-344/94-81 and 50-412/94-81. Based upon the Problem Reports reviewed, the inspector assessed that the Radiation Protection Manager (RPM) - Operations Experience Group (OEG) Manager interface had improved since no inadequacies in causal coding were noted. With the exception of improper high radiation area entries, discussed in Section 5.1.4 of this report, and monitoring system discrepancies, no repetitive failures and no items of regulatory significance were noted. Problem Reports generally dealt with issues of minor radiological safety significance.

Quality Assurance (QA) surveillances from January 1, 1995 to time of the inspection were reviewed. No items of regulatory significance had been identified. Poor radiation worker practices had been identified in several surveillances and the QA department intended to target this area in future surveillances.

In summary, those portions of the licensee's audit and appraisal program reviewed were considered very good.

5.1.2 Changes to the Radiation Protection Program

Since the last inspection in this area, nine radiological controls technician (RCT) positions were eliminated. Four dosimetry technician positions were eliminated, leaving six dosimetry technician positions. The four dosimetry technicians whose positions were eliminated were moved to field operations (leaving a total of 47 individuals in field operations).

The RPM informed the inspector that the radiation safety committee (RSC) will cease reviewing all non-intent (not safety related) procedure changes. The RPM was evaluating whether an individual should be moved to maintenance planning.

No degradation of the radiation protection program is expected as a result of these changes.

5.1.3 Training and Qualifications of Personnel

The inspector discussed with the RPM the licensee's efforts in enhancing personnel qualifications/expertise. The RPM provided a list of such efforts to the inspector which included visits to other nuclear facilities since January 1, 1995. The inspector considered these efforts extensive and included participation in audits/peer reviews and attendance at various workshops/seminars.

At the time of the inspection, two individuals within the Radiation Protection Department were in the plant certification program.

In summary, those portions of the licensee's training and qualification program reviewed were considered very good.

5.1.4 External Exposure Control

High Radiation Areas and Access Controls

On July 28, 1995, a licensee health physics technician identified two individuals from the in-service inspection group in an area posted and controlled as a high radiation area (Unit 2, 710' elevation of the primary auxiliary building). The area was posted in accordance with licensee procedures for a high radiation area. The two experienced radiation workers were directed by a RCT to meet at the work location. The two individuals proceeded to enter the posted high radiation area without a proper radiation monitoring device. Previously, the barrier to this high radiation area had been established at a doorway and the barrier had been moved inside the room shortly before this event had occurred. The individuals stated to the inspector that as they were approaching and entering the area, they were conversing with each other on the best method of completing their assigned task in the most expeditious manner. After entering the high radiation area, the individuals proceeded to don their anti-contamination clothing. Shortly thereafter, the individuals were discovered inside the high radiation area by the same RCT noted above, who then discussed the matter with his supervision.

As shown by subsequent surveys, the area did not actually contain radiation fields meeting the high radiation criteria established by the licensee's technical specifications.

Licensee corrective actions implemented at the time of the inspection included the following.

- The individuals' authorizations for radiologically controlled area access were removed.
- The event was included in the station morning meetings at which the event would be discussed by management with their respective staff members.
- An investigation was initiated. The area was resurveyed and the barricades moved to encompass more discrete areas of the 710' elevation. The inspector considered the licensee's investigation to be very good. Individuals formally trained in root cause determination conducted the event investigation.
- The individuals were counseled by radiation protection and by the workers' departmental management. The individuals were required to discuss this matter during a meeting with their peers.
- The event will be included in the annual general employee refresher training as a lesson learned item.

- A disciplinary policy for station supervision regarding high radiation area access controls was established and disseminated.

- A letter was prepared and signed by the Division Vice President, Nuclear Operations. The letter discussed the importance of high radiation area controls, previous events, the postings and barricades used at BVPS, the requirements for making a proper entry into an area controlled as a high radiation area, and management's expectations. This letter was handed out to personnel as they entered the protected area on August 21, 1995. Subsequently, copies were left at the security badge issuance point.

Additionally, the inspector noted two licensee initiatives which will further impact the quality of worker adherence to established high radiation area controls:

- The licensee was evaluating an integrated electronic self-reading dosimetry (ESRD)/access control system.

- The licensee established a high radiation area square foot performance indicator. This was considered a good initiative on the part of the licensee. The licensee had initiated this program in response to the concerns highlighted in NRC Inspection Report 50-334/95-07 and 50-412/95-07 and the recent improper high radiation area entries.

In conclusion, the failure to adhere to high radiation area access controls constituted a violation of radiological controls procedures, was of minor consequence and is being treated by the NRC as a non-cited violation, consistent with Section VII.B.1. of the NRC Enforcement Policy.

Dosimetry Program

At the time of the inspection, the licensee maintained an onsite thermoluminescent dosimeter (TLD) laboratory. The licensee used Panasonic Model UD812 dosimeters which had been accredited in the first seven test categories established by ANSI N13.11. The licensee used Landauer Neutrak-ER dosimeters for use in known neutron radiation fields. (This vendor is currently accredited in the eighth test category established by ANSI N13.11.)

Typically, the licensee did not use the Landauer dosimeters to assess the neutron component of the dose of record. The use of Eberline rem-balls with PNR-4 meters and stay times was the preferred method of assessing the neutron dose of record at BVPS. The licensee had performed a neutron energy spectrum study for both BVPS containment buildings. The licensee study indicated that the majority of the dose from neutrons in the containment buildings was from neutrons with energy less than 100 keV. No neutrons with energy greater than 1 MeV were detected during the study. The licensee found that both the rem-ball/PNR-4 detector/meter combination with stay times method and the Neutrak-ER dosimeter over-responded to the existing energy spectrum. The study noted that typically, neutron dosimeters lacked practicality because the majority of neutron exposures had been less than 30 mrem and the vendor had reported a practical lower threshold of detection of 40 mrem with the Neutrak-ER dosimeters. In summary, the study justified the current calibration factors of the rem-ball/PNR-4 detector/meter and also justified the current practice of using the rem-ball/PNR-4 to measure dose equivalent rate multiplying by the exposure time to determine dose equivalent from neutrons.

The licensee was monitoring the effectiveness of the program by sending batches of dosimeters to the University of Michigan for irradiation in selected test categories and by the subsequent evaluation at the onsite laboratory on a quarterly basis. The licensee quality control program had also established periodic tests for the TLD readers, which included heating cycle, electrometer, and alignment testing. The licensee's laboratory had also maintained trending charts of reader voltage setpoints. The inspector was also informed that the licensee's existing stock of TLD holders had been checked for acceptability of window thickness. At the time of the inspection, the licensee was developing a Quality Manual for the personnel TLD program.

Dosimeter Inconsistency Dose Assessment Record forms (used to evaluate anomalous TLD data and lost dosimeters) from January 1, 1995, were reviewed. No inadequacies in licensee conclusions were noted. The inspector verified that individual doses of record had been modified as appropriate as a result of the discrepancy evaluations.

Overall, quality control over the TLD program was found to be very good. The neutron dosimetry program was reviewed and found acceptable.

External Exposure Control Program Summary

Overall, this program area was considered good. Weak performance was noted in the worker implementation of the established program for access to high radiation areas.

5.1.5 Internal Exposure Control

The licensee's primary method for the evaluation of internal doses was the utilization of whole body counting. Two Canberra whole body counters, a stand-up model (FASTSCAN) and bed type (ACCUSCAN), were used for this purpose. Each unit was subject to daily background check(s), and multiple source checks. The results were plotted by hand on control charts, with an established action limit of +/- 3 standard deviations. On an annual basis, a calibration of each instrument was conducted using a ten-peak standard. Additionally, the licensee verified the whole body counter's calibration after six months in order to monitor the average relative bias and relative precision using the ten-peak standard.

In conclusion, whole body counting quality control was considered to be very good.

5.1.6 Maintaining Occupational Exposures ALARA

Goals for 1995 were considered by the inspector to be realistic. The inspector was informed that rework factors were not added to job ALARA targets as a matter of practice. There was no allocation of the budget goal for contingency work/outages. As a consequence, the 1995 ALARA goal will likely be exceeded as a result of the unplanned outages.

The inspector noted very good results from hot shutdown chemistry. The licensee estimated that about 315 Ci of Co-58, 4.6 Ci of Co-60, and 1035 grams of nickel were removed from the reactor coolant system during the shutdown prior to the tenth refueling outage at Unit 1 (denoted by the licensee as 1R10). The licensee estimated that about 635 Ci of Co-58, 5.5 Ci of Co-60, and 1186 grams of nickel were removed from the reactor coolant system during the shutdown prior to the fifth refueling outage at Unit 2 (2R05).

A Health Physics Surveillance Report was generated by the licensee to make an assessment of how the reduction of respirator usage had impacted ALARA on similar work-scope radiation work permits (RWPs) for 1R09 and 1R10. The inspector noted that RWPs covering steam generator work and certain in-service inspection activities formed the largest portion of the data selected by the licensee. The following information demonstrating a reduction of respirator use was provided by the licensee.

Outage	Respirators Used	Outage	Respirators Used	% Reduction
1R09	2876	1R10	262	90%
2R04	2605	2R05	128	95%

During 1R10, a total of 2,119 mrem committed effective dose equivalent (CEDE) was assessed by the licensee to individuals with the highest individual assessment being about 40 mrem. During 2R05, a total of 770 mrem CEDE was assessed. The highest individual CEDE assessment for an individual participating in both 1R10 and 2R05 was 49 mrem. When comparing similar work scope RWPs between 1R09 and 1R10, licensee data indicated that total effective dose equivalent (TEDE) had been reduced by 35 person-rem during 1R10. When comparing 2R04 and 2R05 in a similar manner, licensee data indicated that TEDE had been reduced by about 30 person-rem.

In conclusion, a large decrease in the number of respirators prescribed for protection against radioactive material in the most recent refueling outages conducted by the licensee was noted. There was no significant increase in CEDE, while deep dose equivalent (DDE) had been reduced by a significant amount for some similar work-scope jobs.

The Radiation Protection Department has received approval from engineering to store ladders and scaffold piping in designated storage locations within the containment building. The inspector considered this action to be a good ALARA initiative.

Overall, those portions of the ALARA program which were reviewed were considered very good.

5.1.7 Control of Radioactive Materials and Contamination, Surveys and Monitoring

The inspector reviewed licensee report "1995 Skin and Clothing Contamination Review for January 1 through June 30," dated August 4, 1995. The inspector assessed this report as providing very good trending of personnel contaminations. The inspector also assessed that although two refueling outages had occurred in 1995, personnel contaminations appeared somewhat high. The report noted that 287 skin contaminations and 275 personnel clothing contaminations had occurred during the period of review. It should be noted that the licensee has established a low reporting threshold, since any case showing greater than 100 cpm over background, whether on an individual or an individual's clothing, is recorded and tracked for future review. No skin exposures of regulatory significance were noted by the inspector. The report noted few cases in which skin exposures exceeded more than 1 rem shallow dose equivalent.

The licensee attributed 156 of the cases to decisions made by the Radiation Protection Department in regard to keeping exposures ALARA. Past practice had been to prescribe/use double sets of protective clothing for a particular task, whereas during the most recent refueling outages, only a single set of protective clothing had been prescribed/used to maximize worker efficiency and minimize heat stress.

Radiological housekeeping was considered very good for the areas toured.

5.2 Security

Implementation of the physical security plan was observed in various plant areas with regard to the following: protected area and vital area barriers were well maintained and not compromised; isolation zones were clear; personnel and their packages were properly searched and access control was in accordance with approved licensee procedures; security access controls to vital areas were maintained and persons in vital areas were authorized; security posts were properly staffed and equipped, security personnel were alert and knowledgeable regarding position requirements; written procedures were available; and lighting was sufficient.

5.3 Annual Emergency Preparedness Exercise

The licensee's annual emergency preparedness exercise was conducted from 8 a.m. to noon on July 26, 1995. This was a limited participation exercise. The Commonwealth of Pennsylvania and the States of Ohio and West Virginia provided personnel to participate in the Emergency Operations Facility (EOF) and the Joint Public Information Center, but no offsite agency facilities were activated.

Overall, exercise performance was good and demonstrated that the licensee was able to implement the Emergency Plan to protect the health and safety of the public. No exercise strengths were identified. Technical Support Center (TSC) involvement in evaluating conditions that place the plant outside of the emergency operating procedures (EOPs) was identified as an area for improvement. Two exercise weaknesses were identified: (1) Due to misinterpretation of an emergency action level (EAL) criterion, a Site Area Emergency (SAE) was declared prior to meeting all the criteria for the declaration. (2) The Pennsylvania Emergency Management Agency (PEMA) was not informed of the Site Area Emergency until 1 hour and 20 minutes after the declaration.

5.3.1 Exercise Scenario

The exercise scenario that was simulated started with a contaminated, injured man and a small leak to the environment from the Unit 1 refueling water storage tank. Neither condition met emergency declaration criteria. Next, a 30 gpm reactor coolant system leak was indicated in the Unit 1 'C' steam generator. This met Unusual Event criteria. The leak eventually progressed to a rupture, meeting Alert declaration criteria. Site Area Emergency criteria were finally met when the steam generator with the ruptured tube became faulted inside of containment, and the containment depressurization system failed to actuate as required. The exercise was terminated once containment pressure control was restored and pressure returned to subatmospheric conditions.

The licensee's exercise scenario and the associated objectives were reviewed by the inspectors and were found consistent with NRC expectations for off-year exercises.

5.3.2 Observations

As dictated by the exercise scenario, licensee activities occurred primarily in the control room, the Operations Support Center (OSC), the TSC, and the EOF. The areas primarily observed by the inspectors were the control room, the OSC and the TSC. Activities in the EOF were observed briefly following the SAE declaration.

Control Room

The Nuclear Shift Supervisor (NSS) accurately classified the Unusual Event and the Alert. All offsite notifications for the Unusual Event and the Alert were made within the required time limits. The shift of emergency director responsibilities from the NSS to the Unit Operations Manager was accomplished smoothly. Communications between the control room staff and other licensee emergency response facilities were good. Overall, the control room staff demonstrated very good use of procedures, a high level of integrated plant knowledge, and effective response to simulated plant events.

During the previous annual emergency exercise it was identified that the NSS often unnecessarily duplicated the information passed to the TSC instead of allowing the Operations Coordinator to handle information flow, potentially distracting him from plant control duties. During this exercise, the NSS was not unnecessarily distracted by communications with the TSC. Based on this observation, this area for improvement from the previous exercise is considered closed.

Operations Support Center

The Operations Support Center (OSC) provided good support in the evaluation and repair of equipment needed to mitigate the accident as specified in the exercise scenario. Prioritization of repair tasks was clear and communicated to the OSC staff. Feedback from the repair teams was effective and allowed the OSC coordinator to accurately track the status of the repair efforts. Accountability was properly stressed, and repair team efforts were well coordinated with the Radiological Operations Center (ROC) with one exception. Communication difficulties between the ROC and OSC resulted in a 15 minute delay in sending out a field team to the emergency diesel generator.

In contrast to the previous annual exercise, it was evident that the OSC was in charge of the dispatched repair teams. However, areas for improvement involving the control of the drill still exist. For example, the OSC was unsuccessful in obtaining an up-to-date status on equipment that was initially out of service because the repair crews were only simulated and thus the OSC had no individual to contact for real time information. Also, confusion existed between the controller and the OSC regarding the return of the diesel generator to service. The single controller in the OSC was overloaded in critiquing the drill and providing status updates to the OSC coordinator.

Technical Support Center

The TSC was activated approximately 36 minutes after the Alert declaration. In general, good communications were noted in the TSC and between the TSC and other licensee emergency response locations. Effective communications, however, were not demonstrated with all offsite agencies. During this exercise, PEMA was not notified of the SAE until 1 hour and 20 minutes after the declaration. This occurred because the TSC Communicator inadvertently auto-dialed the Beaver County Emergency Management Agency (BCEMA) twice during the initial notifications. The second call to BCEMA was logged as the initial notification to PEMA. One hour and 20 minutes later, PEMA was notified of the SAE during what should have been a follow-up notification. During an actual event or a full participation exercise, this mistake would not have resulted in such untimely PEMA notification. BCEMA is required by procedure to contact PEMA to verify the emergency declaration. This likely would have resulted in PEMA notification within 15 minutes of the SAE declaration. The failure to notify PEMA of the SAE declaration within 15 minutes was identified as an **exercise weakness** (IFI 50-412/95-13-02).

Another **exercise weakness** was identified when the SAE was declared prior to meeting all of the criteria (IFI 50-412/95-13-03). Indicated plant conditions involved a faulted steam generator that was also faulted inside of the containment building. Containment pressure was rising, and was close to the phase-B containment isolation (CIB) pressure (8 psig), the point at which the quench spray system automatically actuates. The criterion for a potential loss of the containment barrier, which was the additional criterion need for the SAE declaration, was "CNMT pressure >8 psig with less than one full train of CNMT spray." The A-train of containment (quench) spray was not available because the AE emergency bus was not available, but there was no reason to believe the B-train of quench spray was not available. The Emergency Director

(ED), however, was convinced that he needed to declare a SAE when containment pressure reached 8 psig. This was discussed with and agreed to by the Emergency Recovery Manager (the EOF was activated by this time). At 10:20 a.m., it was clear that containment pressure would exceed 8 psig, and the SAE was declared. Eight minutes later the TSC was informed that the train-B quench spray system failed to start. According to the licensee's Emergency Plan, this was the point at which the SAE declaration should have be made.

Overall, the TSC provided effective support for plant operations. Equipment repair priorities were clearly established and continuously evaluated, and technical support was generally provided as needed. The TSC was not, however, involved in evaluating the implications and subsequent actions associated with disabling all recirculation spray pumps. All four recirculation spray pumps were placed in pull-to-lock by the control room operators when the complete loss of quench spray was recognized. This action was outside of the EOPs, but prevented pump damage since the pumps would have started without adequate water in the containment sump. After quench spray was returned to service, the operators placed the recirculation spray pumps back in operation following the standard post-CIB time delay. This may have been the only reasonable course of action, but it was never evaluated by the TSC. Consequently, TSC involvement in evaluating conditions that place the plant outside of the emergency operating procedures (EOPs) was identified as an **area for improvement**.

Emergency Operations Facility

The EOF was activated approximately 1 hour and 11 minutes following the Alert declaration, and 10 minutes prior to the SAE declaration. This was a conservative action since EOF activation is not required until after declaration of a SAE or a General Emergency (GE). The inspectors did not have any further observations concerning the EOF.

Personnel Accountability

Accountability was begun when the SAE was declared, and was complete in 20 minutes. No problems with accountability were noted by the licensee or the inspectors.

Recovery Operations

Following the drill, the Emergency Director and the Emergency Recovery Manager discussed the actions necessary to terminate the emergency and recover the plant. The discussions were very thorough and appropriately covered the requirements of the licensee's Emergency Plan.

Licensee Critique

On July 27, the licensee held a formal critique of the exercise. The critique was appropriately self-critical, and identified all of the NRC findings with the exception of the area for improvement. Closing comments by the Vice President for Nuclear Services demonstrated senior management's concern for the decline in performance in the area of offsite communications. The inspectors concluded that this was a very good self-evaluation. Following the critique, the inspectors informed the licensee of the NRC findings, and met with senior licensee managers to discuss the identified exercise weaknesses. The managers indicated strong dedication to understanding and correcting the weaknesses.

5.4 Housekeeping

Plant housekeeping controls were monitored, including control and storage of flammable material and other potential safety hazards. The inspectors conducted detailed walkdowns of accessible areas of both Unit 1 and Unit 2. Housekeeping at both units was acceptable.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (71707, 62703, 61726, 37551, 71750)

6.1 Unit 1 Problem Reports

The problem reports listed below were reviewed to evaluate the licensee's effectiveness in identifying, evaluating, resolving and preventing problems.

1-94-225 Inadequate Reactor Coolant System Relief Path

While researching Unit 1 pressurizer power operated relief valve (PORV) stroke time problems, a system engineer noticed that the orifice diameter of the Unit 1 PORVs was smaller than previously assumed. The orifice diameter was thought to be 2 inches (the valve nominal trim size) vice 1.625 inches. The 2 inch diameter corresponds to the reactor coolant system vent opening required by Technical Specifications as a method of overpressure protection and as part of the boron injection flow path for the low head safety injection pumps. The 1.625 inch opening would not meet Technical Specification requirements simply by blocking open one PORV, as had been the practice.

The licensee did not do a root cause evaluation for this problem, apparently due to its age, but also did not justify this deviation from the problem report administrative procedure which requires a root cause analysis for all reportable events. The licensee's problem report file indicated that corrective actions were focused on evaluating the actual PORV vent size for adequacy, evaluating the applicability of the problem at Unit 2, and ensuring that Unit 1 Technical Specification requirements were met by blocking open two PORVs vice one. The problem report file did not document any evaluations of the operability of the overpressure protection system (OPPS) at either unit. Through discussions with the licensee, the inspectors determined that the licensee had recognized and evaluated the OPPS operability issue prior to using the systems in the plant outages that followed the discovery of this problem. On June 6, 1995, the licensee formally documented an evaluation that showed the PORV orifice diameters at both units were adequate to meet all design overpressure conditions. The inspectors noted that the documentation did not include an evaluation of the adequacy of the boron injection flow rate. Following discussions with the inspectors, the licensee showed that the boron injection rate would be satisfactory.

The licensee is submitting a Technical Specification change request to change the vent size requirements to match the PORV orifice area. The inspectors concluded that, overall, the licensee took adequate actions to correct and evaluate the problems that resulted from misinterpretation of the Unit 1 PORV orifice diameter. However, problem report documentation of the actions was weak. Recognition of the orifice diameter issue by the System Engineer was commendable.

1-95-236 Low Pressure in the Control Room Temperature Control Air System

This problem resulted when an automatic drain trap in the control room temperature control air system failed open and reduced pressure in the system. Low pressure in this system forced operators to declare the control room ventilation suction and exhaust dampers inoperable because it was not known if the air sealing bladders for these dampers would seal properly. Each of the sealing bladders has an appropriately sized air flask that is isolated by a check valve from the temperature control air system. However, at the time of the event, the check valves were not in the inservice testing program, and could not be relied upon for adequate isolation from the low pressure condition in the rest of the system.

The licensee decided to conduct a formal root cause analysis of this event, but more than 8 months following the event the analysis was not complete. The engineers assigned to do the analysis stated that they knew the cause, and simply needed to document it. The cause was said to be corrosion products from the drain trap causing mechanical failure of the trap. The contribution of maintenance program factors to the trap failure still required research.

The long term corrective actions specified in the problem report file were to evaluate the trap design and the temperature control air system low pressure alarm set point (the alarm set point was lower than the pressure required for adequate sealing of the bladders). The response due date for these items was April 10, 1995. As of late July, neither the responses nor a request for due date extension had been received by the Operations Experience Group.

Although not documented in the problem report file, the actual corrective actions taken by the licensee were quite prompt and effective. The event occurred on November 14, 1995. By December 22, all of the system automatic drain traps were replaced with manual drain valves (operators now blow-down the air lines at a frequency determined through dew-point monitoring). In June, all of the bladder air flask check valves were replaced and the valves were added to the inservice test program. The inspectors concluded that these actions were effective and timely, and will prevent recurrence of the problem.

1-95-20 Containment Ventilation Exhaust Flow Exceeds Refueling Limits

The root cause of this problem was determined to be personnel error. A clearance posted on the supplemental leak collection system was not evaluated for potential changes in the ventilation flow balance. The licensee did a root cause evaluation for this event, but the documentation was not sufficient to fully evaluate the adequacy of the evaluation. Long term corrective actions specified for this problem included procedural changes and training at both Units. The inspectors concluded that the corrective actions should prevent recurrence of the problem, and were implemented in a timely manner.

1-95-044 Safety Related 480V Bus Found Seismically Unqualified

The cause of this problem was determined to be an original construction deficiency, and was identified during seismic qualification inspections performed in response to NRC Unresolved Safety Issue A-46. The licensee did not do a root cause evaluation for this problem, apparently due to its age, but also did not justify this deviation from the problem report administrative procedure which requires a root cause analysis for all reportable events. Corrective actions for this problem focused on correcting the deficiency, and evaluating opposite train equipment for similar deficiencies. The inspectors concluded that timely, appropriate corrective actions were taken for this problem.

1-95-262 Gaseous Waste System Rupture Disk Support Deficiencies
1-95-289

These two problem reports identified seismic support deficiencies associated with three rupture disks in the gaseous waste system. The first problem report (1-95-262) documented deficiencies with RD-GW-100 and 101, and the second report (1-95-289) documented a deficiency with RD-GW-103A2. The deficiencies with RD-GW-100 and 101 were found by an engineer evaluating the acceptability of installing locking devices on two valves in the vicinity of the rupture disks. The deficiency associated with RD-GW-103A2 was found 11 days later when a Nuclear Shift Supervisor questioned the adequacy of the supports for the other eight rupture disks in the gaseous waste system. All three of the deficiencies were apparently introduced during construction of the plant. Two of the rupture disks had an inadequate number of supports, and the remaining rupture disk was not adequately supported by an existing support.

Within 24 hours of the discovery of each deficiency, the licensee completed a basis for continued operation (BCO) evaluation that showed the acceptability of operating with the deficiencies until the next refueling outage. The evaluations used the alternate stress evaluation criteria in Appendix F of Section III of the ASME Code (the 1983 edition), as discussed in Generic Letter 91-18 "Information to Licensees Regarding two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability." Repair of the deficiencies is scheduled for late October 1995.

The inspectors concluded that the licensee correctly evaluated the deficiencies after they were discovered. However, the licensee was slow to evaluate the other gaseous waste system rupture disks once the first deficiency was identified. These observations were discussed with the Operations Experience Group Manager (OEG). The OEG Manager stated that he is considering an administrative change to the problem report procedure to programmatically require an evaluation of the potential for identified problems to exist elsewhere.

Unit 1 Problem Report Summary

Overall, the inspectors concluded that the licensee effectively identified, evaluated and corrected the problems discussed above. It was not possible, however, to draw this conclusion based on review of the problem report files, since in most cases the documentation was incomplete or overdue. The inspectors are aware that the licensee is working to make the problem report system a more effective management tool.

6.2 Offsite Review Committee Meetings

During the report period, the inspectors attended three Offsite Review Committee (ORC) meetings: the full committee meeting, the Operating Experience Subcommittee meeting, and the Maintenance and Engineering Subcommittee meeting. The two subcommittee meetings were chaired by a consultant. The use of consultants as the committee chairmen was a recent improvement that should make the ORC more independent. All three meetings were effective in the evaluation and review of plant activities. Of particular note were the contributions and insights gained from the consultants.

6.3 Missed Technical Specification Surveillance

During a review of operator logs, Quality Assurance personnel identified a missed technical specification surveillance. This involved the failure by operators to manually calculate the quadrant power tilt ratio (QPTR) every 7 days as required by technical specification 4.2.4.a. Surveillance log "L5-27" directs operators to calculate the QPTR every Sunday on the midnight shift. However, an operator on the midnight shift of February 26, instead logged "not applicable." The safety significance of this missed surveillance is minimal, as the QPTR was within limits on February 19 and March 5, and no QPTR alarms were received during this period. Corrective actions include counseling of operators involved and revision of the surveillance log. The licensee plans on submitting a licensee event report. The inspectors considered this finding by the Quality Assurance staff to be notable and indicative of a thorough review of operating logs. A licensee event report is being prepared.

7.0 ADMINISTRATIVE

7.1 SALP Management Meeting

A public meeting was held with Duquesne Light Company management on August 9, 1995, at the licensee's emergency response facility to present the results of the NRC Systematic Assessment of Licensee Performance (SALP). A copy of the slides presented is attached. W. Kane, Deputy Regional Administrator, W. Lanning, Deputy Director, Division of Reactor Projects, and D. Brinkman, Senior Project Manager, attended from NRC Region I and Headquarters. The NRC managers also toured the site and held discussions with plant staff on August 8 and 9.

7.2 Preliminary Inspection Findings Exit

At periodic intervals during this inspection, meetings were held with senior plant management to discuss licensee activities and inspector areas of concern. Following conclusion of the report period, the resident inspector staff conducted an exit meeting on September 1, 1995, with Beaver Valley management summarizing inspection activity and findings for this period.

7.3 Attendance at Exit Meetings Conducted by Region-Based Inspectors

During this inspection period, the inspectors attended the following exit meetings:

Dates	Subject	Inspection Report No.	Reporting Inspector
7/27/95	Valve Mispositioning	95-80	C. Anderson
7/28/95	MOV GL 89-10 Closeout	95-12	J. Trap
8/25/95	Radiological Protection	95-13	L. Eckert

7.4 NRC Staff Activities

Inspections were conducted on both normal and backshift hours: 24 hours of direct inspection were conducted on backshift; 36 hours were conducted on deep backshift. The times of backshift hours were adjusted weekly to assure randomness.

W. Lazarus, Chief, Projects Section 3B, NRC Region I, visited the site on July 27 for discussions with the inspectors.

Beaver Valley SALP Management Meeting

Assessment Period
November 28, 1993 to
June 3, 1995

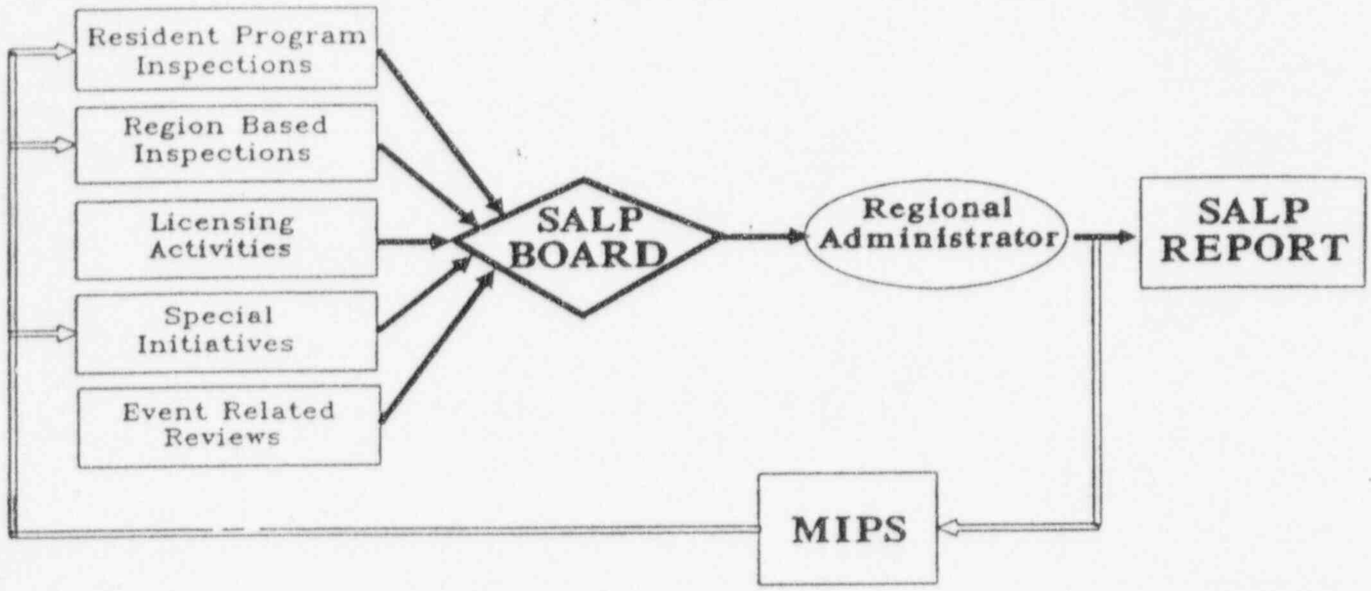
Board Meeting: June 13, 1995
Management Meeting: August 9, 1995

UNITED STATES NUCLEAR REGULATORY COMMISSION

Agenda

• Introductory Remarks	W. Kane Deputy Regional Administrator
• DLCo Comments	J. Cross Senior Vice-President
• Report Presentation	W. Lanning Deputy Director, Division of Reactor Projects
• DLCo Response	J. Cross
• Closing Remarks	W. Kane
• Public Questions	NRC

SALP Process



Performance Analysis Areas for Operating Reactors

- Plant Operations
- Maintenance
- Engineering
- Plant Support
  - » Radiological Controls
  - » Chemistry
  - » Emergency Preparedness
  - » Security
  - » Fire Protection
  - » Housekeeping

Performance Category Ratings

- Category 1: Superior Safety Performance
  - » Programs and procedures provide effective controls
  - » Self-assessment efforts are effective
  - » Corrective actions are comprehensive
  - » Recurring problems are eliminated
  - » Resolution of issues is timely
  - » Minimum inspections to verify safety
- Category 2: Good Safety Performance
  - » Corrective actions are usually effective, although some may be incomplete
  - » Licensee programs and procedures normally effective, however deficiencies may exist
  - » Root cause analyses are normally thorough
  - » Additional inspections necessary
  - » Self-assessments are normally good, although some issues may escape identification
- Category 3: Acceptable Safety Performance
  - » Insufficient control of activities in important areas
  - » Self-assessments ineffective in preventing problems
  - » Lack of understanding of safety implications of significant issues
  - » Corrective actions are not thorough
  - » Shallow root cause analyses
  - » Significant NRC and licensee attention required

SALP Category Ratings

	Previous	Current
• Operations	1	2
• Maintenance	2	1
• Engineering	2	2
• Plant Support	1	1