U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.	92-30 92-29
Docket Nos.	50-334 50-412
License Nos.	DPR-66 NPF-73
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:	December 22, 1992 - January 25, 1993
Inspectors:	Lawrence W. Rossbach, Senior Resident Inspector Peter P. Sena, Resident Inspector

Approved by: W. J. Lazarus 2/9/93
W. J. Lazarus, Chief, Reactor Projects Section No. 3B Date

Inspection Summary

This inspection report documents the safety inspections conducted during day and backshift hours of station activities in the areas of: plant operations; radiological controls; surveillance and maintenance; emergency preparedness; security; engineering and technical support; and safety assessment/quality verification.

EXECUTIVE SUMMARY
Beaver Valley Power Station
Report Nos. 50-334/92-30 & 50-412/92-29

Plant Operations

Overall, both units were operated safely and conservatively without any significant operational events. For a short duration (1 minute), the licensee inadvertently failed to maintain at least one senior reactor operator in the Unit 1 control room. This error was recognized by the operator upon his return to the control room. This event was of minor safety significance and considered to be an isolated oversight by a single individual. This was a non-cited violation.

Radiological Controls

The final phase of the licensee's spent fuel pool cleanup project was properly planned and executed. This involved the shipment of 172 curies of irradiated hardware/waste. Good health physics practices were demonstrated and contributed to exposures being less than projected.

Maintenance and Surveillance

Maintenance and surveillance activities were properly completed per approved procedures with good supervisory oversight.

Engineering and Technical Support

Degraded river water flow through the Unit 1 recirculation spray heat exchangers, while still greater than the technical specification minimum, was thoroughly evaluated by the licensee. Flow rates are currently considered adequate to ensure the plant operates within its design basis. The licensee's short-term actions to flush the heat exchangers weekly was considered prudent. The licensee's planned outage activities should eliminate the problem of silt accumulation.

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DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

On January 1, the management organization of Beaver Valley was restructured. Under the new organization, four executive level positions replaced the previous single position of Vice President, Nuclear Group. At the same time, all maintenance functions were consolidated under a new general manager of maintenance position. Other organizational and personnel changes were also made which resulted in new personnel in four of the five general manager positions. The reorganization is described in more detail in Section 8.1.

Unit 1 operated at 90% power throughout this inspection period without any significant operational events. The utility operates Unit 1 at 90% power to accommodate lower system demand and to extend the fuel cycle.

Unit 2 operated at full power from the beginning of this inspection period until December 24. From December 24 until January 4, power was reduced to 46% due to a lower system demand. From January 6 until January 9, power was reduced to 90% to repack moisture separator reheater drain pump 22B. From January 22 until January 24, power was reduced to 45% to extend the fuel cycle and due to lower system demand. Power was limited to 90% for the remainder of this inspection period due to the failure of moisture separator reheater drain pump 22B on January 24 during the return to full power.

2.0 PLANT OPERATIONS (71707, 93702)

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: recirculation spray, hydrogen recombiners, safety injection accumulators, river water, auxiliary feedwater, and supplemental leak collection and release. 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
- Safeguard Areas
- Service Buildings
- Turbine Buildings
- Intake Structure
- Yard Areas
- Containment Penetration Areas

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 except as discussed in Section 2.2 below. 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. The inspectors observed various alarm conditions and confirmed that operator response was in accordance with plant operating procedures. Compliance with TS and implementation of appropriate action statements for equipment out of service was 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.

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.

2.2 Failure to Maintain Proper Control Room Staffing

On January 14, 1993, the licensee failed to maintain the proper number of senior reactor operators (SROs) within the Unit 1 control room. The normal shift compliment includes two SROs; the Nuclear Shift Supervisor (NSS), and the Assistant Nuclear Shift Supervisor (ANSS). As per previous practice, the NSS exited the control room at 8:30 a.m. to attend the daily planning meeting. The NSS did inform the ANSS that he was exiting the control room. 10 CFR 50.54.m.2.iii requires that "when a nuclear power unit is in an operational mode other than cold shutdown or refueling, each licensee shall have a person holding a SRO license for the nuclear power unit in the control room at all times." Contrary to this requirement, the ANSS exited the control room at 8:50 a.m. in order to verify that a fire watch was posted in the cable tray mezzanine area directly below the control room. The ANSS was aware of the requirement to maintain a SRO in the control room during power operations but did not realize that the NSS was still at the planning meeting. The ANSS had informed the reactor operator that he was exiting the control room; however, the reactor operator was unaware that the NSS had not yet returned. Upon the return of the ANSS to the control room, the on-shift reactor operator and the ANSS immediately recognized the failure to meet the required staffing levels and informed licensee management.

Subsequent review of the security computer log indicated that the ANSS was outside of the control room for 1 minute. As corrective action, the ANSS has been counseled and will conduct training for other operating crews as to the circumstances of this event. The inspector reviewed this incident and concluded that it was an isolated oversight by the ANSS.

The inspector has previously observed good communications between SROs when either the NSS or ANSS had to exit the control room. The overall safety significance of this event was minor because of the short duration the SRO was outside of the control room and because the unit remained at steady state power operations with two reactor operators stationed in the control room. The failure to maintain at least one SRO in the control room is a violation of 10 CFR 50.54.m.2.iii. However, this violation is not being cited in accordance with Section VII.B of the Enforcement Policy due to the isolated nature of the incident, licensee identification, and implementation of proper corrective action.

3.0 RADIOLOGICAL CONTROLS (71707)

Posting and control of radiation and high radiation areas were inspected. Radiation work permit compliance and use of personnel monitoring devices were checked. Conditions of step-off pads, disposal of protective clothing, radiation control job coverage, area monitor operability and calibration (portable and permanent), and personnel frisking were observed on a sampling basis. Licensee personnel were observed to be properly implementing their radiological protection program.

3.1 Spent Fuel Pool Cleanup Activities

The inspector observed the final phases of the Unit 1 spent fuel pool cleanup activities involving the loading of the disposal liner into the TN-RAM shipping cask. Spent fuel pool irradiated waste components previously underwent direct waste characterization and disposal liner loading (see NRC inspection report 92-24). The disposal liner contents included burnable poison rod assemblies, rod control cluster assemblies, thimble plugs, and other miscellaneous hardware for a total of 172 curies of activity.

Temporary operating procedure 1TOP-92-12 was employed by licensee personnel to control the processing, packaging, and transportation of the irradiated hardware. Prior to lowering the shipping cask into the spent fuel pool cask area, the licensee had to partially drain about 6 feet of water from the deep pit area. This was necessary to prevent the overhead crane hook from being immersed in borated water. A submersible pump was used to transfer about 14,000 gallons into the fuel transfer canal. During this evolution, the inspector observed that the licensee had temporary water level indication installed in the deep pit in order to mark the final desired water level. This helped to ensure that about 5 feet of water remained above the liner. A radiation technician continuously monitored radiation levels at the water surface during the draining evolution. Measured dose rates were less than 1-2 mR/hr. The inspector also noted good control of airborne activity by licensee personnel. The transfer canal was covered and taped with yellow poly, and a HEPA filter was used to ventilate the canal as it filled with water.

Prior to draining the cask area, weir gates were installed to separate the spent fuel pool from the cask deep pit and the transfer canal. While the cask area was being drained, licensee personnel monitored the spent fuel pool level and noted about a 3-inch decrease in water

level. One of the weir gates was evidently leaking by. The licensee demonstrated good job preplanning as contingency measures were available to restore the spent fuel pool level. Technical specifications require a minimum of 23 feet of water above the top of the fuel racks. The licensee normally maintains about 24 feet of water above the spent fuel and was able to maintain water level above technical specification requirements. In the event of a weir gate failure, alarm response procedure 10M20.4.ACC, "Spent Fuel Pool Level Low," could have been used to make up borated water from the refueling water storage tank. Calculations previously performed by the licensee indicated that even with only 16 feet of water above the spent fuel, the dose rate to a worker at the fuel pool bridge would be less than 0.01 mR/hr.

When the desired water level in the deep pit cask area was reached, the shipping cask was lowered into the water. The refueling bridge was locked and chocked over the spent fuel area directly adjacent to the cask area. This measure, as well as oversight by the refueling supervisor, quality control personnel, and the crane spotter, ensured the heavy load did not travel over the fuel assemblies in the storage pool. Licensee personnel wet down the shipping cask with primary-grade water to minimize contamination. The inspector questioned health physics personnel as to the expected change in pool boron concentration since the cask was also filled with 400 gallons of primary-grade water. Licensee personnel had already calculated that the addition of 2,000 gallons of primary-grade water would decrease the pool boron concentration from 2,046 ppm to 2,036 ppm. The minimum technical specification boron concentration is 1,050 ppm. After the shipping cask was loaded into the water, the deep pit cask area was refilled from the transfer canal. This allowed licensee personnel to load the disposal liner into the cask. About 2 feet of water remained above the liner as it was aligned into the cask. Dose rates at the water surface were again continuously monitored and were consistent with those previously calculated by the licensee.

Overall, the inspector concluded that the final phase of the spent fuel pool cleanup project was properly planned and executed. Good management attention to this evolution was evident by the on-scene presence of the Operations Manager and the Health Physics Managers. Licensee personnel demonstrated good health physics practices during the cask loading phase. Personnel exposure was kept to a minimum and below the projected exposure goals. In-depth dose rate calculations were consistent with the actual dose rates experienced and contributed to a safely planned radwaste shipment.

4.0 MAINTENANCE AND SURVEILLANCE (62703, 61726, 71707)

4.1 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.

Maintenance work requests (MWRs) reviewed included:

MWR 15094	Reactor Plant Component Cooling Water Pump Outboard Seal Replacement
MWR 15344	PCV-CC-100 Diaphragm Replacement
MWR 15793	Median Signal Selector TAVE Calibration
MWR 15545	Pressurizer Pressure Loop Protection Channel III Test
MWR 15848	P-MS476 Loop 1 Steamline Pressure Protection Channel IV Calibration
MWR 14889	Check Diesel EDG2-2 Service Water Valve MOV 113D Operation
MWR 15914	Leak Repair Check Valve FWE-43B per Temporary Modification 93-2 and EM 104460
MWR 15965	Troubleshoot RCS RTD-T432

During the calibration of median delta-T-Tave and Tref temperature loops (T-RC408 and T-RC409), the inspector observed good coordination and communication between operations and maintenance personnel. The procedure required certain control systems to be placed in manual control to preclude automatic control problems. Operations and maintenance personnel were cognizant of the potential effects the calibration would have on plant equipment. The inspector also observed good control of lifted leads by the technicians during the calibration.

The repair of the reactor plant component cooling water pump (1CC-P-1A) involved the replacement of the outboard pump seal due to excessive leakage. The foreman provided good oversight of the maintenance activities and identified that the mechanic had incorrectly reassembled the pump seal by placing an O-ring on the wrong side of the mechanical seal gland. The inspector noted that the corrective maintenance procedure (1CMP-15CC-1A-B-C-1M) contained a detailed and accurate cross-sectional diagram of the seal, but was not extensively referenced by the mechanic. The inspector did subsequently observe a good questioning attitude by the mechanic toward the maintenance procedure. For example, the mechanic questioned why the procedure specified that the coupling end bearing be "heated to 350°F" prior to installation on the shaft. Further review by maintenance supervision determined that 250°F would be sufficient as temperatures in excess of 350°F could potentially damage the bearing.

MWR 015344 involved the replacement of a failed diaphragm for pressure control valve PCV-CC-100. This valve maintains a constant component cooling water (CCW) pressure to system loads by recirculating water from the 24-inch discharge header to the pump suction header. Due to the diaphragm failure, the licensee had to place the CCW system in an abnormal lineup in order to maintain proper system pressure. This involved isolating CCW flow to the spent fuel pool heat exchangers. Initial spent fuel pool temperature was 81°F. The Operations Manager appropriately conveyed the operational priority of repairing this valve to the procurement and maintenance departments. The licensee maintained the capability to reinitiate cooling water flow to the heat exchangers at all times, and spent fuel pool temperature was continuously monitored. Maintenance supervision properly allocated additional manpower to the repair effort after it was determined that the entire valve actuator needed to be removed for the diaphragm replacement. The repair effort was completed in a timely manner, and cooling water was reinitiated prior to pool temperature exceeding 100°F.

Overall, the maintenance activities observed by the inspector were completed by skilled individuals, per approved procedures, and with appropriate management or supervisory oversight.

4.2 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 following operational surveillance tests (OSTs) and maintenance surveillance procedures (MSPs) and temporary operating procedures (TOPs) were reviewed:

OST 1.30.3	Reactor Plant River Water Pump 1B Test (see 6.1)
OST 1.7.5	Centrifugal Charging Pump Test (1CH-P-1B)
OST 2.46.3	Six Month Hydrogen Recombiner 21A Test
OST 2.15.2	Primary Component Cooling Water Pump 21B Test
1 TOP-92-08	Operations for Maintenance of PCV-1PG-117
1 TOP-93-05	Reverse Flush of 1B or 1D Recirculation Spray Heat Exchanger (see 6.1)

The observed surveillance activities were properly conducted without any notable deficiencies.

5.0 SECURITY (71707)

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 vehicles entering and packages being delivered to the protected area were properly searched and access control was in accordance with approved licensee procedures; persons granted access to the site were badged to indicate whether they have unescorted access or escorted authorization; security access controls to vital areas were maintained and persons in vital areas were 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 illumination was maintained. Licensee personnel were observed to be properly implementing and following the Physical Security Plan.

6.0 ENGINEERING AND TECHNICAL SUPPORT (37700, 37828, 71707)

6.1 River Water Flow Degradation of Unit 1 Recirculation Spray Heat Exchangers

On January 21, 1993, the licensee declared the 1B recirculation spray heat exchanger (RSHX) inoperable after determining that the river water flow through the heat exchanger was inadequate. The licensee was in the process of conducting operational surveillance test 1.30.3, "Reactor Plant River Water Pump 1B Test." The licensee has previously experienced river water flow degradation through these heat exchangers and was taking action to monitor/improve the flow rates (see NRC inspection reports 90-20, 91-23, and 92-20). These actions have included an asiatic clam control program, river water intake bay cleaning, the use of a silt dispersant, monthly system flushing, and heat exchanger cleaning (while in cold shutdown).

Each RSHX is a vertical one pass heat exchanger through which river water flow is required for post-accident heat removal. The RSHXs (RS-E-1A, 1B, 1C, and 1D) are aligned such that two heat exchangers per train receive flow from one river water system header in a parallel flow arrangement. Technical specification 3.6.2.2 requires that four separate recirculation spray subsystems, each composed of a spray pump, heat exchanger, and flow path, be operable. A river water flow rate of at least 8,000 gpm is required through each train. The technical specifications do not specify a minimum river water flow rate for individual heat exchangers.

On January 18, 1993, during surveillance testing, river water flow through the 'B' heat exchanger was determined to be 3,700 - 3,800 gpm. The surveillance test acceptance criteria was 4,000 gpm in order to verify that inlet check valve RW-195 stroked full open. The licensee was able to increase this flow to 4,600 gpm following full flow river water flushing individually through each heat exchanger. Total flow through both train 'B' heat exchangers (RSHXs B and D) simultaneously was 8,025 gpm.

During a repeat of the surveillance test on January 21, the initial river water flow through the train 'B' heat exchangers was only 7,600 gpm. The licensee was able to increase the flow above the 8,000 gpm acceptance criteria to 8,100 gpm by again flushing the heat exchangers individually. However, this did represent a flow degradation of over 400 gpm in only 3 days. Additionally, the individual flow through the 'B' RSHX was only 3,500 gpm. The licensee was unable to increase this flow above the 4,000 gpm surveillance test acceptance criteria. The licensee declared the 'B' RSHX inoperable and applied the technical specification action statement which required the heat exchanger to be returned to operable status within 7 days.

The design basis river water flow is based on a loss of coolant accident (LOCA) occurring with a maximum river water temperature of 90°F. The river water would remove the decay heat (via the RSHXs) in the containment following the LOCA. The design basis calculations assume an equal flow split of 4,000 gpm per heat exchanger. The Updated Final Safety Analysis Report (table 9.9-3) lists a minimum flow requirement of 8,000 gpm through an individual recirculation spray train with 4,000 gpm per heat exchanger specified in parenthesis. The licensee had previously performed an analysis assuming a reduced river water temperature of 75°F and demonstrated that the required flow rate for design basis heat removal could be reduced to 6,000 gpm. A temporary waiver of compliance was previously approved by the NRC to allow the licensee to operate with less than 8,000 gpm total flow between October 1990 and April 1991.

After declaring the 'B' RSHX inoperable, the licensee disassembled and removed check valve RW-195 for inspection. No deficiencies were identified by the licensee or the inspector. The licensee believes that silt accumulation has been the cause of the degraded river water flow. The RSHXs are normally isolated from the river water system by RW-103A, B, C, and D. The licensee has previously identified that these valves leak by and thus allow silt to deposit within the heat exchangers. The licensee attempted to reverse flush the 'B' heat exchanger from the fire protection header via a fire hose. Licensee personnel and the inspector noted that very little silt was removed by this action since the fire water flow was limited by a 3/4-inch vent line connection. The licensee re-performed the surveillance test on January 24. Initial flow through both the 'B' and 'D' RSHXs was only 7,800 - 7,900 gpm. The licensee was again able to increase the total flow through both heat exchangers above the 8,000 gpm acceptance criteria by forward flushing each heat exchanger individually. However, the 'B' RSHX remained below the 4,000 gpm acceptance criteria with only 3,200 gpm with its outlet valve in the normal throttle position. The flow rate through the 'D' RSHX only, was 5,400 gpm.

An engineering analysis was performed to evaluate the effects of various flow split assumptions for river water through the RSHXs while maintaining the minimum train requirement of 8,000 gpm. The inspector reviewed this evaluation which analyzed the heat transfer capability of the heat exchangers. The analysis concluded that a flow imbalance of up to 3,000/5,000 gpm split between the 'B' and 'D' heat exchangers is acceptable without

degrading the RSHX capacity based on the current tube plugging margin. Based on this analysis, satisfactory inspection of check valve RW-195, and a total train flow rate greater than 8,000 gpm, the licensee declared the 'B' RSHX operable.

As short-term corrective action, the licensee plans on performing a forward flush of the 'B' train heat exchangers on a weekly basis. This inspector considered this a prudent action, given that river water flow has previously degraded to less than 8,000 gpm in less than 1 week. The inspector will continue to monitor the river water system for flow degradation during these tests. As long-term corrective action, the licensee plans on replacing the river water header isolation valves to the RSHXs during the ninth refueling outage commencing in March 1993. With these new isolation valves, the licensee will be able to maintain the RSHXs in chemical wet layup. This was originally planned for the April 1991 refueling outage, but the valve vendor went out of business prior to the outage. The Unit 2 RSHXs are maintained in dry layup and have not been as susceptible to biofouling or silt accumulation as the Unit 1 RSHXs.

In summary, the licensee showed good safety perspective in pursuing the degraded river water flow while still above the technical specification minimum. Operational priorities were appropriately communicated to engineering for completion of the safety evaluation. Proper action has been initiated to monitor and ensure adequate river water flow up to the outage. Engineering support was thorough and enabled the licensee to conclude that the plant could operate safely within its design basis.

7.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (40500, 71707, 90712, 91700)

7.1 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 followup. The following LERs were reviewed:

Unit 1:

92-12 Potential Trip of Emergency Bus 480 Volt Unit Substation Supply Breaker on CIB Signal

A review of the station service voltage and load analysis calculation noted that pressurizer heaters powered from Class 1E 480 volt busses 8N and 9P are assumed to be off during a containment isolation phase B (CIB) evolution. A scenario involving a steam line break inside containment initiating a CIB signal and a corresponding rise in pressurizer level

causing automatic pressurizer heater operation was identified. This scenario was not previously analyzed for loading considerations on the 480 volt supply breakers for the 8N and 9P busses powering the pressurizer heater with offsite power available. A calculation determined that the supply breaker current may exceed the 8N breaker trip setting (110% of the 1600 ampere breaker full load rating) causing a breaker trip. The 9P breaker has a higher overcurrent trip setting and is expected to remain energized. The cause of this event was an inadequacy in the original design basis calculation assumptions. The licensee has developed administrative guidance requiring the pressurizer heaters powered from the 8N and 9P 480 volt busses to be placed in the pull-to-lock position to preclude automatic operation. The technical specification minimum of 150 kw of pressurizer heaters being operable is still satisfied. The overcurrent trip setting of the 480 volt supply breakers is being evaluated to determine permanent corrective action.

Unit 2:

92-13 Steam Generator Blowdown Isolation

The steam generator blowdown isolation valves closed on high level in the blowdown tank due to a plugged blowdown demineralizer outlet filter. Blowdown was restored through a standby demineralizer, and the filter was replaced. Plant operation was not affected by this event. The inspectors have no additional comments on this event.

The above LERs were reviewed with respect to the requirements of 10CFR50.73 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.

8.0 ADMINISTRATIVE

8.1 Reorganization and Management Changes

On January 1, the management organization at Beaver Valley was restructured. Under the new organization, four executive level positions replaced the previous single position of Vice President, Nuclear Group. J. D. Sieber, who was the Vice President, Nuclear Group, became the Senior Vice President and Chief Nuclear Officer of the Nuclear Power Division. G. S. Thomas, who was the Nuclear Services Unit General Manager, became the Vice President, Nuclear Services. D. E. Spoerry, who was the Nuclear Operations Services Unit General Manager, became the Vice President, Nuclear Operations. W. S. Lacey, who was the Nuclear Planning and Development General Manager, became the Assistant Vice President, Nuclear Planning and Development.

Also on January 1, organizational changes were made which consolidated all maintenance functions under a new general manager of maintenance position. S. C. Fenner, who was assistant to the maintenance manager, became the Maintenance Programs Unit General

M'.nager. He reports to the Vice President, Nuclear Operations. Other organizational and personnel changes were also made which resulted in new personnel in three of the other four general manager positions. L. R. Freeland, who was the Unit 1 Operations Department Manager prior to an 18 month assignment with INPO, became the Nuclear Operations Unit General Manager. T. P. Noonan, who was the Nuclear Operations Unit General Manager, became the Nuclear Engineering and Safety Unit General Manager. He reports to the Vice President, Nuclear Services. E. Chatfield, who was the Nuclear Training Manager, became the Nuclear Support Unit General Manager. He also reports to the Vice President, Nuclear Services.

8.2 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 February 5, 1993, with Beaver Valley management summarizing inspection activity and findings for this period.

8.3 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
1/15/93	Erosion/Corrosion/RCS Fatigue	93-02/02	Kaplan; Lohmeier

8.4 NRC Staff Activities

Inspections were conducted on both normal and backshift hours: 21 hours of direct inspection were conducted on backshift; 3 hours were conducted on deep backshift. The times of backshift hours were adjusted weekly to ass: re randomness.

J. Linville, Chief, Region I, DRP Branch 3, visited the site on January 11 and 12 for discussions with the inspectors and utility management and to tour the site.