U. S. NUCLEAR REGULATORY COMMISSION
Region I

Report Nos.	50-334/88-23 50-412/88-18	License Nos.:	DPR-66 NPF-73

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

Facility name: Beaver Valley Power Station, Units 1 and 2

Location: Shippingport, Pennsylvania

Dates: July 16 - August 31, 1988

Inspectors: J. E. Beall, Senior Resident Inspector
S. M. Pindale, Resident Inspector

Approved by: Lowell E. Tripp 9/21/88
Lowell E. Tripp, Chief Date
Reactor Projects Section No. 3A
Division of Reactor Projects

Inspection Summary: Combined Inspection Report Nos. 50-334/88-23 and 50-412/88-18 for July 16 - August 31, 1988

Areas Inspected: Routine inspections by the resident inspectors of licensee actions on previous inspection findings, plant operations, security, radiological controls, plant housekeeping and fire protection, maintenance, surveillance testing, emergency preparedness exercise, generic letter responses, use of aluminum power cable, potential loss of containment isolation, river water system expansion joints, inoffice review of licensee event reports and review of periodic reports.

Results: One violation was identified regarding the failure to adhere to administrative procedures (Section 10). Two unresolved items were opened regarding 1) the appropriate use, installation and maintenance of aluminum power cabling in both Unit 1 and Unit 2 safety related equipment (Section 9), and 2) the development of a justification for continued operation and identification of root causes and corrective actions regarding a lower than expected river water system expansion joint design pressure on the "C" recirculation spray heat exchanger (Section 11). While overall plant housekeeping was found to be acceptable, a slight decline was observed in several Unit 1 radiologically controlled areas. Three previously open NRC items were closed.

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DETAILS

1. Persons Contacted

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

2. Summary of Facility Activities

At the beginning of the inspection period, both Unit 1 and Unit 2 were operating at full power. A Unit 2 reactor trip occurred on July 27, when several control rods fell into the core initiating a negative neutron flux reactor trip signal during maintenance troubleshooting activities (Section 4.2.1). The unit was returned to full power on July 29, and continued until August 18, when Unit 2 commenced a load reduction to about 35% power due oil sample results of the main transformer which showed the presence of combustible materials (Section 4.2.3). Upon reviewing the results of additional samples, and determining that the results were acceptable, the unit was returned to full power later that day. On August 22, both Unit 1 and Unit 2 began a manual plant shutdown in accordance with the provisions of Technical Specifications (Section 4.2.4). An unusual event was declared due to an apparent nearby or onsite potentially harmful release (chlorine), and the control room emergency pressurization system automatically actuated resulting in the entry into Technical Specifications. Both units were taken off-line early on August 23. Unit 1 was returned to full power on August 24 and continued until the end of the inspection period with the exception of a manual load reduction to about 50% from August 27-29 in an effort to extend core life in order to effect a later refueling outage start date. Unit 2 reached 30% power on August 23; however, commenced a plant shutdown due to a 10 CFR Part 21 issue that affected several safety-related valves (Section 10). The Unit reached Mode 4 (Hot Shutdown) on August 24 before all affected valves were inspected and modified. Mode 1 (Power Operation) was entered on August 25 and full power was reached on August 26, which continued until the end of the inspection period.

3. Followup on Outstanding Items

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

3.1 (Closed) IFI (50-334/85-02-04): Unexplained voltage shifts of control rods during power operation. Troubleshooting of deviations between control rod position indicating (RPI) system values and associated group demand counter indications concluded that the deviations were caused by a shift in RPI primary voltages. Exact causes for the shifts have not been identified nor can the licensee predict when such a shift will occur. Extensive trending of system parameters and specific troubleshooting directives have assisted the licensee in quickly identifying and resolving the infrequent occurrences. Additionally, this issue has been the subject of vendor (Westinghouse) and generic industry communications and resolution efforts. Some postulated causes for the deviations are coil stack temperature variations, secondary leakage, inductance, magnetism, inductance and cross coupling. This recognized industry-wide concern does not represent a significant safety problem so long as the system is monitored and maintained by the licensee. The inspector reviewed the licensee's testing and trending program associated with this system and found them to be effective for identifying and resolving such potential concerns. Based on the above, this item is closed.

3.2 (Closed) Unresolved Item (50-334/88-04-01): Modify safety injection system leakage test method to ensure that specific portions of piping are full so that minor valve leakage could readily be detected. The licensee revised Operations Surveillance Test (OST) No. 1.11.16, Leakage Testing RCS Pressure Isolation Valves, to include steps to fill and vent the lines prior to performing the OST. The Onsite Safety Committee reviewed the procedure change which became effective August 12. The inspector reviewed the approved change and no deficiencies were identified. This item is closed.

3.3 (Closed) Unresolved Item (50-412/87-61-01): Reevaluate as-built flows for the Supplementary Leak Collection and Release (SLCR) System emergency modes and revise the FSAR to reflect the new flow rates. The licensee adjusted and balanced the SLCR system in accordance with final system turnover requirements and station procedures. The licensee re-evaluated and documented the as-left flow rates and found them to be acceptable. The inspector reviewed the associated documentation and no deficiencies were identified. The licensee updated the FSAR to reflect the necessary changes. One group of design parameters (the "A" train normal exhaust fan) was inadvertently omitted from the UFSAR. The licensee stated that the above design parameters will be included in the next UFSAR amendment and is currently being tracked internally as an open action item. The inspector also reviewed TSs to verify consistency with final system evaluation flow rates and FSAR parameters. The TS values do not currently reflect the as-found flow rates; however, a proposed TS change request was submitted by the licensee to the NRC by letter dated August 11, 1988. The proposed changes include revising system flow rate values to be consistent with those in the most recent UFSAR submittal. Implementation of the approved TS change, including revision of the appropriate procedures, will be reviewed during a subsequent routine inspection. For the interim, the licensee plans to use and satisfy the current TS acceptance criteria. Based upon completion and disposition of final system performance parameters, this item is closed.

4. Plant Operations

4.1 General

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

-- Control Room
-- Auxiliary Building
-- Switchgear Area
-- Access Control Points
-- Protected Area Fence Line
-- Turbine Building
-- Safeguard Areas
-- Service Building
-- Diesel Generator Buildings
-- Containment Penetration Areas
-- Yard Area
-- Intake Structure

4.1.1 ESF Walkdown

The operability of selected engineered safety features systems were verified by performing detailed walkdowns of the accessible portions of the systems. The inspectors confirmed that system components were in the required alignments, instrumentation was valved-in with appropriate calibration dates, as-built prints reflected the as-installed systems and the overall conditions observed were satisfactory. The systems inspected during this period include the Emergency Diesel Generator, Quench Spray and Auxiliary Feedwater Systems. No concerns were identified.

4.1.2 Onsite Safety Committee

The inspector attended an Onsite Safety Committee (OSC) meeting on August 25. Technical Specification 6.5.1 member attendance requirements were met. The agenda included procedure, incident report and design change package reviews. The meeting was generally characterized by frank discussions and questioning of the relevant issues. No significant concerns were identified.

4.2 Operations

During the course of the inspection, discussions were conducted with operators concerning knowledge of recent changes to procedures, facility configuration and plant conditions. During plant tours, logs and records were reviewed to determine if entries were properly made, and that equipment status/deficiencies were identified and communicated. These records included operating logs, turnover sheets, tagout and jumper logs, process computer printouts, unit off-normal and draft incident reports. The inspector verified adherence to approved procedures for ongoing activities observed. Shift turnovers were witnessed and staffing requirements confirmed. Inspector comments or questions resulting from these reviews were resolved by licensee personnel. In addition, inspections were conducted during backshifts and weekends on July 31 - 9:30 a.m. - 3:30 p.m.; August 5 - 12:30 a.m. - 6:00 a.m.; August 17 - 2:15 a.m. - 6:00 a.m.; August 20 - 9:00 a.m. - 5:00 p.m.

4.2.1 Reactor Trip Due to Dropped Control Rods

On July 27, the Unit 2 reactor automatically tripped from full power due to a power range negative neutron flux reactor trip signal when several control rods fell into the reactor core. Prior to the event, plant operators were performing Operations Surveillance Test (OST) 2.1.1, Control Rod Assembly Partial Movement Test, which verifies the operability of each control rod by moving them at least 10 steps. The control room operators were unable to move the rods in Shutdown Bank A. Additionally, the ability to move the rods in Control Banks A and C was dependent upon which direction the bank selector switch was rotated when selecting the individual banks. The rods operated properly in all other individual banks, and the manual and automatic modes of rod control also functioned properly.

Technicians were troubleshooting problems with the rod control system when a stationary gripper circuit card was removed. This action immediately resulted in dropping several control rods into the reactor core. The technician performing the troubleshooting activities believed that removing the card would automatically generate only a rod urgent alarm and engage the moveable gripper latches to hold the associated control rods in place. Licensee followup investigation and consultation with the system vendor (Westinghouse) found that this is true only if two other associated circuit cards are operational and the above automatic actions occur before the affected control rods begin to fall into the reactor core (due to the disengaging of the stationary gripper latches upon card removal). However, due to a bad circuit card (one of the other two), removing the stationary gripper circuit card resulted in dropping control rods. The licensee subsequently replaced the defective card and successfully tested the rod control system. The plant response to the trip was normal and the reactor was taken critical on July 28. Full power operation resumed on July 29.

The licensee performed a systematic root cause evaluation to identify all contributory factors and to recommend corrective actions. The root cause analysis was completed on August 3, and attributed the event to several cause categories, including lack of specific troubleshooting procedures, inadequate system design knowledge and an inadequate retraining program. Licensee proposed corrective actions include 1) developing a guide to assist technicians in troubleshooting the rod control system, 2) reviewing this event with technicians in future training sessions, and 3) periodically retraining technicians on the rod control system. Implementation and the effectiveness of licensee corrective actions will be reviewed during a subsequent inspection.

4.2.2 Chlorine Gas Release

On August 3, an Unusual Event was declared at 9:30 am for the Beaver Valley Site while both units were operating at full power, in accordance with Emergency Preparedness Plan requirements due to the release of chlorine gas. Licensee personnel were in the process of replacing three empty chlorine cylinders when, during the performance of a fitting leak check on the first cylinder that was connected, the operator observed leakage. He attempted to tighten the fitting, however, the leakage worsened. In less than one minute, the operator isolated the affected cylinder by closing the associated isolation valve. Personnel in an adjacent area sensed the chlorine odor and notified control room personnel, who immediately dispatched the Emergency Squad, evacuated the Unit 1 turbine building and other areas adjacent to the chlorine cylinder area, and declared the Unusual Event. The licensee made the appropriate notifications in accordance with 10 CFR 50.72 reporting requirements.

Both control room ventilation systems were in the recirculation mode of operation at the time of the event. Neither ventilation unit experienced an automatic actuation signal from its associated chlorine detection system. Air samples in all adjacent areas were subsequently taken using portable instruments. No adverse chlorine conditions were detected. Access to the above areas was then returned to normal and the Unusual Event was terminated at 10:20 a.m.

Two operators were assigned to the job. The operator performing the cylinder changeout activities was dressed in the appropriate protective clothing, including a self-contained breathing apparatus. His clothes, which carried a strong chlorine odor following the event, were removed and the individual was showered on-site. The licensee sent all individuals (approximately 12) who were in close proximity to the chlorine cylinder area during the event or who were involved in response activities to a local hospital for evaluation as a precautionary measure. No adverse physical conditions were identified and the individuals subsequently returned to work.

4.2.3 Unit 2 Power Reduction

On August 18, while operating at full power, the licensee was informed of possible damage in the Unit 2 main transformer. Results from a previous transformer oil sample indicated the presence of combustible gases which was indicative of possible transformer internal arcing. Licensee management directed a controlled plant shutdown at 11:15 a.m. in order to examine the transformer, and personnel access to the affected area was restricted. Concurrent with the unit shutdown efforts, a second sample was taken and sent offsite for analysis. The unit was holding at 25% power awaiting the results of the second oil sample. The results indicated only traces of combustibles and the unit was returned to full power operation. A third, confirmatory sample was sent to an offsite contractor and the results were good. Results of future main transformer oil samples will be closely monitored by the licensee. The inspector will also monitor the future periodic oil sample results during routine inspections.

4.2.4. Chlorine Detection System Actuation, Manual Shutdown

On August 22 at 7:02 p.m., Unit 2 detected chlorine gas on one out of three chlorine detection system (CDS) channels. The Unit 1 CDS actuated at 7:13 p.m. on a two out of three coincidence. Unit 1 and Unit 2 share a common control room. The Unit 1 CDS actuation caused a control room isolation and air pressurization to occur. In addition, a chlorine odor was reported by plant personnel near the river which borders the site. Plant operators were immediately dispatched to search for chlorine leaks; however, none was identified. The five subsystems (each subsystem consisting of two large compressed air bottles) of the control room emergency bottled air pressurization (CREBAP) system began to discharge into the control room. The licensee declared an Unusual Event at 7:55 p.m. in accordance with Emergency Preparedness Plan requirements (nearby or onsite release potentially harmful). After plant operators used portable chlorine detectors and verified that no chlorine was present, the five CREBAP subsystems were manually isolated. Additional chlorine detection tests were performed which confirmed that no chlorine was present and the Unit 1 CDS annunciators were subsequently cleared. The Unusual Event was terminated at 8:40 p.m. The notifications required by 10 CFR 50.72 were properly made by the licensee.

Since more than one of the five subsystems depressurized below the Technical Specification (TS) limit of 1825 psig (all subsystems were depressurized to between 1240 psig and 1470 psig), TS 3.0.3 was entered and both units commenced a plant shutdown in accordance with the provisions of TS 3.0.3 at approximately 8:30 p.m. Unit 2 reached Mode 3 (Hot Standby) at 1:00 a.m. on August 23 and Unit 1 entered Mode 3 at 1:35 a.m. The licensee supplemented the CREBAP system repressurization efforts by using portable compressors, including equipment transported from a local fire department. At 4:05 a.m., four CREBAP subsystems were pressurized to 1825 psig. At 5:17 a.m. the CDS isolation circuit was reset and TS 3.0.3 was exited since the four subsystems were restored, therefore, a plant shutdown to Modes 4 and 5 was not required. The licensee remained in the Action Statement requirements of TS 3.7.7 (Control Room Habitability Systems) until 6:35 a.m., at which time all five CREBAP subsystems were restored to normal pressure and the system was restored to normal system alignment.

At the close of the inspection, the source of the chlorine had not been identified. On August 23, licensee investigators were sent to a nearby coal-fired facility, and inquiries were made of other neighboring facilities. Although no confirmation has been obtained, the licensee feels that an actual short-lived chlorine release was the cause for the event due to the common actuation of both Unit 1 and Unit 2 CDSs and due to plant personnel detecting a chlorine odor at about the time of the event.

Only one CREBAP system compressor was available at the time, resulting in a long repressurization time. The other system compressor and the onsite portable unit were both out of service. A new, previously ordered compressor is now onsite and the licensee is in the process of connecting it to the existing system to provide additional system capacity. Additionally, the licensee has made agreements with local agencies to promptly provide supplemental compressed breathing quality air, if needed. These efforts are in an attempt to prevent future plant shutdowns in the event that the CREBAP system discharges. The inspector will monitor the licensee's continuing investigation regarding the source of the chlorine and the effectiveness of licensee activities during future inspections.

4.2.5 Feedwater Isolation

On August 23, during a Unit 2 startup following the August 22 shutdown (Section 4.2.4), a feedwater isolation occurred. During the startup, a turbine trip test was performed as required by station procedures. Immediately following the turbine trip, the steam flow in all three steam generators (SGs) momentarily spiked high resulting in SG level increases due to feedwater "swell". The "B" SG level increased to its high-high setpoint, thereby automatically tripping the remaining main feed pump, isolating feed flow and actuating the Auxiliary Feedwater System. SG levels were subsequently returned to normal and the plant startup (to 30% power) was successfully completed later that day. The licensee notified the NRC of this event in accordance with 10 CFR 50.72 reporting requirements.

The [illegible] initially believed that a misoperation of the st[illegible] system caused the steam flow spike, however, sub[illegible] inve[illegible] determined that the system contr[illegible] fun[illegible] properly. Additionally, plant op[illegible] in the manual mode of operation.

Further investigation identified that the "B" atmospheric steam dump valve was leaking steam. The licensee subsequently concluded that the valve had lifted due to the elevated header pressure following the turbine trip, thereby worsening the effects of the steam flow spike. Also contributory to this event, was the fact that with the steam dump system in manual automatic pressure control is inhibited. To prevent similar events during subsequent plant startup evolutions, the licensee is considering incorporating procedure changes to ensure that the steam dump system is maintained in automatic while performing the turbine trip test. Interim guidance has already been provided to plant operators. The inspector will review the effectiveness of the licensee's actions during future inspection.

4.2.6. High Ambient Temperature Effects

For several consecutive days during this inspection, the outside air temperature was in excess of 90 degrees F. Several nuclear plants experienced problems with meeting Technical Specification (TS) requirements with respect to ultimate heat sink temperatures. The Ohio River is the ultimate heat sink for the Beaver Valley Site. TS 3.7.5 for both units requires that the average water temperature be less than or equal to 86 degrees F. Additionally, TSs specify an upper containment average air temperature limit of less than or equal to 105 degrees F. While both parameters increased during the periods of elevated outside air temperatures, the TS values were not reached. The maximum river temperature was 84.5 degrees F, and was reached on August 18. The maximum containment average air temperature during the period was 102 degrees F (Unit 1). Additionally, electrical equipment was not adversely affected by the high temperatures. Towards the end of the inspection period, ambient temperatures had decreased, and plant parameters had returned to normal values.

4.3 Plant Security/Physical Protection

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 being maintained and that persons in Vital Areas were properly authorized.

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

-- Adequate illumination was maintained.

No deficiencies were identified.

4.4 Radiological Controls

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. No concerns were identified.

4.5 Plant Housekeeping and Fire Protection

Plant housekeeping conditions, including general cleanliness conditions and control and storage of flammable material and other potential safety hazards, were observed in various areas during plant tours. Maintenance of fire barriers, fire barrier penetrations, and verification of posted fire watches in these areas were also observed. The inspector conducted detailed walkdowns of the accessible areas of both Unit 1 and Unit 2. One noted improvement was the installation of "curbing" surrounding potential sources of radioactive leakage (e.g., pumps). This improvement is an effective means to control the spread of radioactive contamination. Overall, housekeeping was found to be adequate for both units. Individual deficiencies, primarily in Unit 1 radiologically controlled areas, were identified to the licensee for resolution.

5. Maintenance

The inspector reviewed selected maintenance activities to assure that:

-- the activity did not violate Technical Specification Limiting Conditions for Operation and that redundart 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;

-- where necessary, radiological and fire preventive controls were adequate and implemented;

-- QC hold points were established where required, and observed;

-- equipment was properly testeo `nd returned to service.

Maintenance activities reviewed included:

MWR 880121 Inspect EE-EG-1 Air Start System Strainer for Debris.

MWR 882244 Troubleshoot FCV-FW-499.

No deficiencies were identified.

6. Surveillance Testing

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 surveillance testing activities were reviewed:

MSP 6.13 P-456 Pressurizer Pressure Protection Channel II Test.

OST 1.36.2 Diesel Generator No. 2 Monthly Test.

OST 2.11.2 Low Head Safety Injection Pump Test.

OST 2.24.4 Steam Turbine Driven Auxiliary Feed Pump Test.

No deficiencies were identified.

7. Emergency Preparedness Exercise

On August 16, the licensee conducted a Unit 1 Emergency Preparedness mini-drill. The drill scenario was such that appropriate actions taken by participating personnel could impact the outcome of events. This is an innovative approach to developing drill scenarios for the station. Industry guidelines were used in developing the scenario. Two such potential events were prevented or mitigated by prompt and effective personnel response. The overall performance by the participants was good. Deficiencies noted during drill critique included minor communication and Emergency Squad coordination problems. Resolution of these items are being tracked by the licensee internally.

8. Generic Letter 88-05

Generic Letter (GL) No. 88-05, Boric Acid Corrosion of Carbon Steel Reactor Boundary Components in PWR Plants, was issued on March 17, 1988. By letter dated May 31, 1988, the licensee responded to the GL describing a commitment to a boric acid leakage monitoring and preventive program. By letter dated August 24, 1988, the NRC determined that the licensee met the requirements of GL 88-05. The inspectors will periodically verify proper implementation and maintenance of the above program during future inspections.

9. Aluminum Cable on Class 1E Equipment

On August 17, several Unit 1 480-volt bus ground annunciators alarmed in the control room. Coincident with the control room alarms, leak collection exhaust fan VS-F-4A automatically tripped off and Auxiliary Building (752' elevation) smoke alarms annunciated in the control room. Plant operators and the fire brigade immediately responded to the area to investigate and found that smoke was issuing from the ceiling area of 752'. The brigade confirmed that VS-F-4A was the source of the smoke. The fan motor and associated conduit were very hot to the touch. The supply breaker was then racked off the 480-volt bus. Carbon dioxide was sprayed down the conduit to aid in cooling and for smoke removal. The response personnel noted that the wiring in the motor termination end of the conduit was burned. Within an hour, the event was terminated and a fire watch was posted in the area.

The two 100% capacity leak collection exhaust fans (VS-F-4A and VS-F-4B) are part of the Supplementary Leak Collection and Release (SLCR) System. The primary function of the SLCR system is to ensure that radioactive leakage from the containment following an accident or radioactive release due to a fuel handling accident is collected and filtered for radioactive iodine removal prior to discharge to the atmosphere. During normal operation, the exhaust flow is not filtered; but upon automatic system realignment, the exhaust is diverted to the main filter banks and through the elevated release point on top of the reactor containment. VS-F-4B remained operable throughout this event.

The repair of the damage cable involved replacing between 30 to 40 feet of damaged cable with new copper cable. The original power cable was aluminum. Splices were made at the aluminum/copper connections using joint compound to minimize the possibility of galvanic corrosion. On August 30, several days following the repair to VS-F-4A, the licensee identified that the 480-volt motor termination connectors for VS-F-4B were also damaged. The fan unit was declared inoperable and the termination was subsequently repaired. VS-F-4B was returned to service late on August 31.

The licensee determined that the power cable associated with VS-F-4B is also aluminum while the motor connectors are copper. The use of dissimilar metals may lead to excessive cxidation and corrosion under certain conditions. The corrective action for VS-F-4B included removing the copper connectors and installing aluminum connectors. This is an interim measure as is the corrective action for VS-F-4A (replacing a portion of the cable). One long term resolution of this issue being considered by the licensee was to change entire cable runs from the substation to plant components from aluminum to copper cabling using copper connecting lugs. Additionally, the licensee generated a list of all aluminum wiring in Unit 1. An inspection plan for potentially affected components was being developed. The licensee also plans to initiate an investigation to determine if Unit 2 is similarly affected.

The appropriateness of the use, installation and maintenance of aluminum power cable in Category 1E equipment for both units including procedural control; the licensee's inspection plan; and long term approaches to resolution of these issues will be reviewed during a future inspection. Additionally, compliance to the appropriate electrical codes and station procedures will be reviewed. This is an Unresolved Item (50-334/88-23-01). Due to the potentially generic nature of this issue, the licensee was requested to respond formally to the above concerns in writing. Inspector followup of this item will include a review of the licensee's response.

10. Potential Loss of Containment Isolation Capability

On October 14, 1987, the licensee received a telephone notification from a vendor (Xomox Corporation) of a potential defect affecting 15 valves provided for Unit 2. The valves were two-, three-, and four-inch plug valves. The potential existed for certain components inside the valve operator or at the operator-valve stem connection to move out of engagement. Such a disengagement would prevent valve movement and could give incorrect valve position indication. The telephone notification included identification of eleven of the valves by plant installed mark number and the other four as spares. The installed valves included 2IAC*MOV-130, 2IAC*MOV-133, and 2IAC*MOV-134 which are in the containment instrument air system. The vendor indicated that a review for reportability under 10 CFR 21 was being performed. The telephone notification was followed by a letter from the vendor dated October 15, 1987.

The three valves listed above are containment isolation valves and are required to close automatically following certain design basis accidents. The reactor containment building is one of the principal barriers to the release of fission products following a hypothetical accident. The isolation of all penetrations of the containment structure is an engineered safety feature and the design requirements for containment isolation are specified in General Design Criteria (GDC) 54-57 in Appendix A of 10 CFR 50. The Beaver Valley Unit 2 design is in accordance with the GDC as described in Section 6.2.4 of the UFSAR. The design of the non-safety related containment instrument air system is described in Section 9.3.1.3 of the UFSAR. The only components of the containment instrument air system that are safety related are those associated with containment isolation.

Upon notification of the potential defect, the licensee implemented Chapter 17 of the Station Administrative Procedures, "10 CFR 21 Reporting of Defects and Noncompliances." These administrative procedures are required by the Unit 2 Operating License in Section 6.8.1 of the Technical Specifications. Chapter 17 establishes requirements and responsibilities for evaluating and reporting defects and applies to all personnel employed by the licensee who may be involved in the identification, evaluation and reporting process. Figure 1 of Chapter 17 is a form, "10 CFR 21 Evaluation Report." In accordance with Chapter 17, this form was completed on October 14, 1987, contained the vendor notification, including the valve numbers, and was forwarded to the plant manager.

The Chapter 17 procedure requires that the 10 CFR 21 analysis be completed and returned to the plant manager within 30 days. The analysis by the licensee's engineering group, located onsite, is supposed to include the effect of the potential defect and the determination if a potential safety hazard could be created (Chapter 17, Section VI.B.2). The engineering group was tasked with this analysis via an internal memo from the plant manager on October 29, 1987. The memo specified a routine priority (Priority 5) for the task but contained a response due date of November 27, 1987.

The valve vendor notified the licensee in a letter dated November 9, 1987, that another utility had reported the defect under 10 CFR 21. The effect of a valve defect is site specific, that is, it varies with the application of the valve in each specific design. The letter again listed the affected valves by the Unit 2 identification numbers.

For the next several months, licensee and contractor engineers working in the licensee's engineering department evaluated the valve defect. Internal correspondence, telephone notes and vendor facsimile transmissions document a protracted review of exact failure mechanisms, replacement parts availability and reportability review. On August 22, 1988, more than 10 months after the initial vendor notification, licensee engineers concluded that the defects involved a potential safety hazard.

The plant manager was informed of the defect on August 23, 1988, during a Unit 2 startup. The affected containment isolation valves were declared inoperable, the startup was terminated, Unit 2 was shut down. It was found that the potential malfunction which involved possible misalignment in the linkage between the valve operator and valve had not occurred. The valves were subsequently modified to prevent the potential malfunction. Upon completion of the valve modifications, Unit 2 was returned to operation.

Failure to comply w'th the 30-day time limit specified in Chapter 17 of the Station Administration Procedures is a violation (50-412/88-18-01).

11. River Water System Expansion Joints

On August 24, the licensee discovered that the documented design pressure for the four river water system metal expansion joints (MEJs) on the outlet of the Unit 1 recirculation spray (RS) heat exchangers was lower than expected. The current design pressure specification for the four MEJs is 85 psig, however, the installed MEJs were all rated for 50 psig. Subsequent correspondence and review with the manufacturer resulted in upgrading three of the four MEJs to 85 psig. The appropriate documentation was provided to the licensee by the manufacturer. The remaining MEJ (for the "C" heat exchanger) was upgraded to 61 psig. Although the design pressure is 85 psig, licensee calculations (using conservative assumptions) show that the maximum pressure that the MEJ will experience is 57.9 psig. Additionally, all four MEJs have been pressure tested each refueling at pressures in excess of 90 psig without distortion or leakage. The licensee analyzed the above conditions and found the current configuration to be acceptable for the duration of the operating cycle. The licensee plans to replace the "C" MEJ during the next refueling outage. An internal justification for continued operation (JCO) and technical evaluation report (TER) were being developed by the licensee at the end of the inspection period.

The licensee is currently investigating the details of this event to determine the root cause for the problem. The licensee plans to replace the "C" MEJ during the next refueling outage and to reduce the associated "C" relief valve setpoint if the heat exchanger must be isolated from the river water system header for any reason before the next outage. The development of the JCO and TER, root cause determinations and corrective actions will be the subject of a followup inspection (Unresolved Item No. 50-334/88-23-02).

12. Inoffice Review of Licensee Event Reports (LERs)

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

Unit 1:

LER: 87-13-00 Exceeding Technical Specification Surveillance Requirements

Unit 2:

LER: 87-30-01 Revisinn to LER 87-30-00

No deficiencies were identified.

13. Review of Periodic Reports

Upon receipt, periodic reports submitted pursuant to Technical Specification 6.9 (Reporting Requirements) are reviewed. The review assessed whether the reported information was valid, included the NRC required data and whether results and supporting information were consistent with design predictions and performance specifications. The inspector also ascertained whether any reported information should be classified as an abnormal occurrence. The following report was reviewed:

BV-1/BV-2 Monthly Operating Report of Plant Operations for July, 1988.

14. Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. Unresolved items are discussed in Sections 9 and 11.

15. Meetings

Periodic meetings were held with senior facility management during the course of this inspection to discuss the inspection scope and findings. A summary of inspection findings was further discussed with the licensee at the conclusion of the report period on September 2.

On August 31, 1988, NRC and Duquesne Light Company senior management held a media-attended public meeting onsite to discuss the recent Systematic Assessment of Licensee Performance (SALP). The report assessed licensee performance from March 16, 1987 - May 31, 1988 for Unit 1 and from March 1, 1987 - May 31, 1988 for Unit 2.