U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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Licensee:	Duquesne Light Company P. O. Box 4 Shippingport, PA 15077-0004
Facility:	Beaver Valley Power Station, Units 1 and 2
Location:	Shippingport, Pennsylvania
Inspection Period:	November 21, 1995 - January 1, 1996
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Inspection Summary

This inspection report documents the safety inspections conducted during day and backshift hours of station activities in the areas of: plant operations; maintenance and surveillance; engineering; plant support; and safety assessment and quality verification. Additionally, inspections conducted by Region-based inspectors are documented in the areas of engineering and security. The results of these inspections are summarized in the executive summary.

EXECUTIVE SUMMARY
Beaver Valley Power Station
Report Nos. 50-334/95-21 & 50-412/95-21

Plant Operations

Due to an excellent response by station personnel, a ruptured expansion joint in the Unit 1 river water system was quickly diagnosed and isolated. During the event, control room operators maintained good attention to plant conditions, communicated effectively with field operators, and responded effectively so as to minimize the effects of the expansion joint rupture. Station management provided good command and control and contributed to the diagnosis of the event. Station management demonstrated a strong safety focus throughout the replacement of the ruptured expansion joint by ensuring that it was replaced promptly, by reducing the risk of having a plant transient, and by ensuring that the other river water header was not challenged. After review of other rubber expansion joints, station management conservatively elected to shut down Unit 1 to replace other rubber expansion joints, even though the replacement of the expansion joints could have been completed within the 72-hour action statement while remaining at power. Probabilistic risk assessment information was a critical part of this decision making process. The risk assessment led management to conclude that it would be more prudent to perform this maintenance off-line. Operator attention to detail during the plant shutdown and subsequent plant startup was evident as no operator error occurred.

Excellent operator action was also evident at Unit 2 where prompt action to restore main feedwater flow averted the need for an automatic reactor trip. This followed an event in which a transformer failure resulted in the inadvertent de-energization of four non-class 1E buses. Operator action, however, could have been better in a subsequent event involving a partial loss of annunciators. Operators were noted as being overly focused on determining the cause of the problem, vice performing enhanced monitoring of control room parameters associated with the failed annunciators.

Maintenance

Maintenance activities to replace river water rubber expansion joints were comprehensive, as all expansion joints with potential operability concerns were replaced. A review of the preventive maintenance program for expansion joints found that sufficient technical justification existed for those joints for which replacement was previously deferred. Procurement support for the replacement of the expansion joints was very good, as all necessary materials were available for the timely completion of the maintenance. However, room for improvement in procurement support still exists as parts were not available on a timely basis for three overcurrent relays. In this case, an off-normal electrical lineup was in place for longer than necessary and indirectly factored into the loss of the four nonemergency electrical buses.

(EXECUTIVE SUMMARY CONTINUED)

Engineering

The quality of the engineering work outputs was good, including six previously unresolved items involving electrical systems which were inspected and closed. The technical content of the documents was good, and provided sufficient detail to resolve the items.

The root cause analysis of the expansion joint failure was found to be well developed and have a proper technical basis. The engineering analysis determined that flow induced erosion allowed water to penetrate the carcass of the expansion joint and corroded the wire reinforcing bands. Engineering identification of a seismic deficiency involving post-accident monitoring recorders was also found to be indicative of a detailed engineering effort.

While progress is being made at reducing the engineering work backlog, it continues to be large in comparison to the rate of work accomplishment. No issues that would pose an immediate safety concern were identified in the engineering backlog nor were any safety issues being overlooked. However, the timeliness of record updates, engineering response to issues, and the prioritization of issues affecting safety-related equipment, such as the evaluation of lowering the Unit 2 emergency switchgear high temperature alarm, appear to be in need of improvement. Similar conclusions were reached in an audit by the licensee's quality assurance organization. The computer-based workload prioritization system is a good initiative to assign site-wide priorities to all outstanding work and is based upon the affect of the work on plant operation. While it may not always initially reflect the needs of operations and maintenance, mechanisms exist for adjusting priorities, and these are being used.

Plant Support

Health physics activities to dispose of contaminated river water were consistent with the ALARA philosophy of 10 CFR 50, Appendix I. Multiple efforts to process the liquid radioactive waste resulted in a significant decrease in the offsite doses. An error in the cooling tower blowdown flow instrumentation was discovered, which had the potential to impact offsite dose calculations associated with liquid effluent releases since this flow is a dilution factor. Prompt review by effluents personnel determined that this error would have been in the conservative direction. However, Quality Assurance personnel did have prior opportunity to identify this error during an effluents audit, had a field verification of the instruments been completed.

Following the expiration of the contract between the union security force and Burns Security, a lockout of the site's security force members occurred. A review of the post-lockout activities found that the replacement personnel were properly carrying out their duties and responsibilities in accordance with the security plan. Proper contingencies were also in place to ensure unimpeded access of authorized personnel to the station.

(EXECUTIVE SUMMARY CONTINUED)

Safety Assessment and Quality Verification

Quality Assurance assessment involving the review of actions associated with the security force lockout was appropriately initiated by the licensee. A Quality Assurance audit of engineering activities was also reviewed and found to contain valid examples of engineering memorandums in which timeliness of resolution is in need of improvement. Quality Assurance findings were found to be consistent with NRC findings in both of these reviews.

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DETAILS

1.0 MAJOR FACILITY ACTIVITIES

Unit 1 operated at full power from November 21 until December 18, when a plant shutdown was initiated after the licensee declared the 'B' river water system inoperable. The plant entered cold shutdown on December 20. Following the replacement of rubber expansion joints in the river water system, the unit was returned to critical operations on December 25, 1995. Full power operation was reached on December 27.

Unit 2 operated at full power throughout this inspection period except for power reductions to 46% power from November 22 to November 27, and from December 29 to January 2, to conserve fuel.

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: emergency diesel generator lube oil, emergency diesel generator cooling water, river water, essential service bus power supply alignment, and auxiliary feedwater (including main steam supply to the terry turbine). The Unit 1 river water system verification was a detailed inspection in accordance with the guidelines of Section 2.05 of the 71707 Core Inspection Procedure. 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

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 use of overtime by licensed operators was verified to be consistent with Regulatory requirements. 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 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 properly 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 River Water Expansion Joint Failure

On December 15, 1995, while conducting tests on motor operated valve MOV-RW-116A, the isolation valve between the auxiliary river water supply header and the 'A' train of the Unit 1 river water system, 24-inch rubber expansion joint REJ-RW-4A2 in the 'A' river water train ruptured. The 'B' train of the Unit 1 river water system was providing all required cooling loads, and the plant was operating at 100% power when the expansion joint ruptured. Water in the primary auxiliary building was observed by station personnel and was indicated by several sump and drain tank alarms and a gas decay tank oxygen analyzer trouble alarm. The oxygen analyzer, O2A-GW-110-2, is mounted a few inches above the floor next to the manhole containing the ruptured expansion joint. No other safety related equipment was effected. Disposal of water released from the expansion joint is discussed in Section 5.1.2. Excellent response was observed from all station personnel involved in this event. During the response to this event, the inspectors observed that the control room operators maintained good attention to plant conditions, communicated effectively with field operators, and responded effectively so as to minimize the effects of the expansion joint rupture. Station management was also observed in the control room providing good command and control and contributed to the diagnosis of the event. Test personnel, operators, and the system engineer involved with the testing of MOV-RW-116A also contributed to the event response. As a result of the excellent response from all involved, the ruptured expansion joint was quickly diagnosed and isolated.

With the Unit 1 'A' river water header now inoperable due to the ruptured expansion joint, the licensee quickly established plans to replace the ruptured joint and review the operability of other expansion joints. The operability determination for the other expansion joints is discussed in Section 2.3. The replacement of REJ-RW-4A2 was properly planned to ensure availability of the staffing, materials, and procedures needed to complete the replacement in a timely manner. Station management discussed probabilistic risk assessment (PRA) based arguments for completing the repair promptly, while also emphasizing maintaining good work standards and safety. In order to reduce the risk of a plant transient while the 'A' river water header was inoperable, all substation work was halted, no new work clearances were posted except as needed for the REJ-RW-4A2, and any activities that could challenge the 'B' river water header were stopped. As a result of these efforts, REJ-RW-4A2 was replaced, and the 'A' river water header was returned to service in approximately half of the 72-hour technical specification allowable outage time.

The inspector concluded that station management demonstrated a strong safety focus throughout the efforts to replace the ruptured expansion joint.

2.3 Operability Determination of Rubber Expansion Joints

In parallel with the repair efforts to the '4A2' rubber expansion joint, the licensee began reviewing the basis for operability for the remaining expansion joints in the river water system and other saf ty-related systems. Initial efforts focused on the root cause of the failed expansion joint and data gathering for the remaining REJs. Specifically, the licensee obtained the maintenance history of each REJ with respect to service life, test data, and inspection data. The inspectors also independently reviewed and assessed the maintenance history data. The REJ with the highest priority for review was REJ-RW-4B2, the complement of the failed REJ-RW-4A2. Based on the following information, the licensee declared the 'B' river water train inoperable on December 18, 1995, at 1430:

- Previously completed external inspections alone cannot identify the type of internal degradation experienced by REJ-RW-4A2;
- REJ-RW-4B2 had exceeded its 12-year service life by about 8 years;
- Re-review of internal robotics inspection video tapes revealed some discoloration similar to that noted on REJ-RW-4A2.

The inspector considered the licensee's operability determination to be appropriately conservative. Technical Specification 3.7.4.1 specifies that two river water systems must be restored to operable status within 72 hours, or the plant must be placed in cold shutdown within the next 30 hours. Estimates from mechanical maintenance indicated that all expansions joints in need of replacement could be accomplished within the action statement time frame. However, the licensee evaluated the risk significance of removing the 'B' river water header from service for this time period. Based on probabilistic risk assessment (PRA) data, the licensee determined that the incremental increase in core damage probability was unacceptable. Licensee management elected to place the unit in cold shutdown for the replacement of the expansion joints. The inspectors considered the licensee's use of PRA data to be an excellent application of risk based information to assess safety significance and determine a conservative course of action.

2.4 Unit 1 Plant Shutdown and Startup

The inspectors observed selected portions of the plant shutdown and subsequent plant heatup. The inspectors also reviewed the technical specification prerequisites for plant mode changes. No deficiencies were identified. Overall, the inspectors noted good command and control by the shift supervisors. Proper attention to detail by operators was evident. During the plant shutdown and subsequent plant startup, no operator errors occurred which resulted in plant challenges or degraded safety margins. While the plant was in cold shutdown, the inspectors found the operators to be attentive to shutdown cooling concerns and were appropriately monitoring multiple instruments in verifying core cooling. Operators were also found to be familiar with recent industry experience with respect to loss of shutdown cooling events. Shutdown cooling concerns were also highlighted at the morning manager's meeting.

2.5 Unit 2 Loss of 480V Electrical Buses

On December 18, 1995, Unit 2 experienced a failure of the '2-2C' 4160/480 transformer which resulted in the de-energization of four non-class 1E 480V electrical buses. At the time of the transient, 4160V bus 'B' was supplying 480V buses '2C', '2D', '2G', and '2H' via breaker '2B3'. A phase 'A' fault to ground in transformer '2-2C' initiated a voltage transient which tripped open supply breaker 2B3. The inspectors reviewed the cause of the fault and its impact on station operations to ensure safety-related systems were not challenged or degraded.

The above electrical transient had an impact on station operations, as operators had to take immediate action to preclude the need for a reactor trip. The de-energization of the buses resulted in the main feedwater pump recirculation valves failing full open. This resulted in an immediate drop in steam generator level. Operators had observed the feedwater pump recirculation valves open and immediately took manual control of the feedwater regulating valves and bypass valves to the full open position. Plant response was assisted by the auto-start of a third condensate pump from the pressure decrease in the feedwater header. Operators were able to turn steam generator level before the low level reactor trip setpoint of 18.2% was reached. The 'A' steam generator had decreased to 21% narrow range.

After plant recovery, the lost electrical loads were reviewed by operators and Operations Management and compensatory actions were taken where needed. For example, this included enhanced monitoring of the 'C' charging pump lube oil and bearing temperatures since the associated temperature control valve was effected. Timely I & C investigation of a rod control non-urgent alarm verified that power had been lost to one of the backup/redundant power supplies to the logic cabinet. A non-urgent alarm does not affect the ability to move control rods. The inspectors independently reviewed the load lists and noted that component restoration sequencing was properly prioritized. One anomaly did, however, occur during the restoration of the alternate power supply to the essential buses and is discussed in Section 2.6.

The electrical buses, as aligned above, were in an off-normal configuration. Normally, the 'B' 4160V bus supplies only the '2C' and '2G' 480V buses, while the 'D' 4160V bus supplies the '2B' and '2H' 480V buses. The off-normal lineup was necessary due to preventive maintenance on three overcurrent protection relays. This lineup did not result in challenging the load carrying capability of the failed transformer. However, the inspectors noted that this configuration remained in place longer than necessary due to not having replacement parts available for these relays. For example, relay 51-VD203C was found defective during the preventive maintenance checks; however, six identical replacement relays, which had been in stock, were inadvertently scrapped by procurement. There were no reliability, design or safety concerns associated with these original relays. As a result, delays were experienced since the new style replacement relays required an additional review prior to installation. Also, the computer stock status for replacement parts for relays 51-VD1203 and 51-VD-203 indicated that none were in stock; however, parts were actually available and required additional effort to locate in a timely manner. If the electrical lineup was in a normal configuration, only two of the four buses would have been de-energized when the transformer failed.

Overall, the inspectors found that operator response to the initial transient was excellent in taking proper and immediate actions to avert the need for a reactor trip. Licensee evaluation and prioritization of system restoration was also well focused on plant safety. The inspectors discussed the procurement issues with the Procurement Manager, who stated that lessons learned will be incorporated into their ongoing self-assessment.

2.6 Unit 2 Partial Loss of Annunciators

During the restoration of system loads on December 18, from the earlier loss of 480V buses, an unanticipated voltage spike resulted in a partial loss of overhead annunciators at 7:14 p.m. Specifically, operators were restoring the alternate power supply to essential buses 5 and 6 to the standby mode. During normal operation, two uninterruptible power supplies (UPS) power essential buses 5 and 6 via an invertor/rectifier assembly. The alternate power supply is a 480V/120V step down transformer which can automatically supply either essential bus via a static switch if a UPS unit fails. At the time of the voltage spike, the UPS units were in service supplying the essential buses. However, when operators re-energized the transformer, 33 annunciator windows illuminated and would not clear. These windows consisted primarily of the first-out annunciators associated with solid state protection. These include, for example: turbine control oil pressure low; steam generator high/low; pressurizer high level reactor trip, loop low flow reactor trip; neutron flux high reactor trip; containment pressure high; pressurizer pressure high; neutron flux rate high reactor trip; and reactor coolant pump underfrequency/undervoltage. Operators proceeded to test the annunciator windows and verified that the remaining plant annunciators were operable. Operators also verified that solid state protection was not generating the annunciator alarms as the individual channel bistables for the associated annunciators were not illuminated. The inspectors, however, observed that the entire operating crew (*i.e.*, the shift supervisor, shift foreman, reactor operator, and plant operator) were all focused on reviewing electrical prints in an attempt to identify the cause of the partial annunciator failure. It was not evident to the inspectors that enhanced control board monitoring was being accomplished. Abnormal Operating Procedure, AOP 2.5.1, "Loss of Control Room Annunciators," which applies to a loss of all annunciators, directs operators to heighten the frequency of monitoring control board parameters at the discretion of the shift supervisor. The inspector questioned the need for a temporary log so that enhanced monitoring of the parameters associated with the failed annunciators would be accomplished. Although AOP 2.5.1 does not specify the need for a temporary log, the shift supervisor concluded it would be prudent to implement such a log. The inspectors reviewed the licensee's Emergency Action Level Criteria and verified that the conditions for declaring an Unusual Event were not satisfied. The criterion specifies an unplanned loss of most (>75%) annunciators for greater than 15 minutes. In this instance, about 5% of annunciators were out of service. At about 4 hours after the initial voltage transient, the shift technical advisor was able to identify a common fuse for the inoperable annunciator windows. The power supply fuse to the solid state protection computer demultiplexer cabinet (2IHC-DMX) was identified as blown. This fuse was replaced and the annunciators were returned to service at 11:30 p.m. Instrumentation and Controls personnel also verified that the voltage spike had no effect on the operability of the alternate power supply or the uninterruptible power supplies to the essential buses. The inspector considered the STA's investigation in identifying the common link between the failed annunciator windows to be excellent.

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) listed below were observed and reviewed. Unless otherwise indicated, the activities observed and reviewed were properly conducted.

MWR	048804	Re-install Cable Vault Area AC Unit Ductwork
MWR	048588; 048589	Relay VD-51-1203 and 203 Repairs
MWR	048229	Ground investigation for 2MSS-SOV-105C

The steam driven auxiliary feedwater pump has three steam supplies normally available, one supply from each steam header. 2MSS-SOV-105C is associated with the 'C' steam supply. Following a failure of this valve, licensee troubleshooting identified a ground on the solenoid. Technical Specification 3.7.1.2 states that the steam turbine auxiliary feedwater pump must be capable of being powered from an operable steam supply system. With 2MSS-SOV-105C out of service, technical specifications remained satisfied with two independent, 100% capacity, steam supplies to the steam turbine remaining operable as supplied from the 'A' and 'B' steam headers. The inspectors observed that operations did properly prioritize the repair of this valve so that additional redundancy was maintained. Replacement of the solenoid was, however, not successful as the ground re-appeared. Subsequent troubleshooting identified that the ground was heat induced due to steam leakby past the valve seat and appeared when solenoid temperature exceeded 320° F. Repair of the valve seat while at power is not possible due to personnel safety concerns, since single valve isolation to the main steam header would be the clearance boundary. As a precaution, the manual isolation valve (2MSS-17) was shut in order to isolate 2MSS-SOV-105C and prevent further degradation of the solenoid to the point of failure. This action will allow the 'C' steam line to be "available" if needed, following manual operator action. No credit is being taken for this line as being part of the operable steam supply system, thus technical specifications continue to be satisfied. The inspectors concluded that the licensee's course of action was appropriate.

3.1.1 Replacement of River Water Expansion Joints

The inspectors observed various portions of the inspection and replacement of the following rubber expansion joints.

MWRs:	029129	REJ-RW-4A2	'A' River Water Header
	036901	REJ-RW-4B2	'B' River Water Header
	029109	REJ-RW-6B	'1B' Pump Discharge
	029119	REJ-RW-18A	Inlet to 'A' Component Cooling Water Heat Exchanger
	029121	REJ-RW-18C	Inlet to 'C' Component Cooling Water Heat Exchanger
	029111	REJ-RW-7B	Inlet to 'B' Recirculation Spray Heat Exchanger
	029112	REJ-RW-7D	Inlet to 'D' Recirculation Spray Heat Exchanger
	037012	REJ-RW-7A	Inlet to 'A' Recirculation Spray Heat Exchanger
	029127	REJ-RW-24A	Main Header Inlet to Recirculation Spray Heat Exchangers
	037016	REJ-RW-24B	Main Header Inlet to Recirculation Spray Heat Exchangers
	037017	REJ-RW-25B	Main Header Inlet to Recirculation Spray Heat Exchangers
	029176	REJ-CC-16B	Inlet to 'B' Component Cooling Water Pump

Those REJs on the "dry" side of the river water system (*i.e.*, downstream of normally shut isolation valves RW-MOV-103A-D) were found to be in excellent condition. Minor flow induced erosion was identified on the interior of REJ-RW-4B2. This erosion had not yet penetrated through to the carcass of the joint, such that the integrity of the joint was degraded. Overall, the inspectors found the replacement of the REJs to be a complete team effort by licensee personnel. Mechanical maintenance personnel aggressively removed and replaced the REJs in a proficient manner. In fact, mechanical maintenance supervision played a pivotal role in ensuring that all appropriate REJs were replaced, and none were deferred past the current shutdown. Good support from engineering was evident by the completion of the technical evaluation report which reviewed the acceptability of the Garlock replacement expansion joints. Good procurement support ensured all necessary materials were on hand to proceed with the replacement of all necessary REJs. The inspectors also independently reviewed the maintenance history data (inspections, service life, and test data) and assessed that the licensee replaced all those expansion joints in which an operability question existed.

3.1.2 Expansion Joint Preventive Maintenance

An expansion joint preventive maintenance program has been in existence since 1993, and an external inspection program since 1987. Inspections are conducted on an 18-month frequency. The inspectors reviewed the basis for the licensee's justification for deferring the replacement of eight REJs during the previous refueling outage (spring 1995). The following REJs were scheduled for replacement for the upcoming fall 1996 refueling outage:

REJ-RW-4A2	'A' River Water Header;
REJ-RW-4B2	'B' River Water Header;
REJ-RW-7A,B,C	Inlet to Recirculation Spray Heat Exchangers;
REJ-RW-24A,B	Main Header Inlet to Recirculation Spray Heat Exchangers; and
REJ-RW-25B	Main Header Inlet to Recirculation Spray Heat Exchangers

Although the licensee's documentation of the deferment was weak, the inspector concluded that a sufficient technical basis existed for the licensee's decision. Of the REJs listed above, only REJ-RW-4A2 was within its vendor recommended service life of 12 years (by 1 year). The deferment was based on external visual inspections (conducted by both the vendor and licensee) in December 1994, hydrostatic test data from May 1993, and the satisfactory physical condition of those expansion joints that had just been replaced. Additionally, internal robotics inspections were completed on REJ-RW-4A2 and 4B2, and at the time did not indicate any unusual degradation. As long-term corrective action, the licensee is re-evaluating the REJ replacement frequency to be more consistent with actual field performance.

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-24.9 Turbine-Driven Auxiliary Feedwater Pump Operability Test

The inspectors noted that proper corrective actions were in place to preclude the possibility of cold air affecting the performance of the turbine governor. Previously, during start-up activities last year, a ventilation damper was left open for an excessive period. This allowed cold, outside air to affect the viscosity of the governor oil, and thus affect speed control of the governor.

1/2OST-44A.12 CIB Actuation of Control Room Isolation/CREBAPS

1OST-21.4 Main Steam Trip Valve Full Closure Test

1OST-2.4A	Quadrant Power Tilt Ratio Manual Calculation
1OST-46.3	Hydrogen Recombiner 1A Semi-Annual Test
1/2OST-43.17A	Control Room Area Monitor [1RM-218A] Functional Test

4.0 ENGINEERING (37550, 37551)

4.1 Root Cause Analysis of Expansion Joint Failure

The rubber expansion joint which failed (REJ-RW-4A2) was manufactured by the Goodall Rubber Company. An expansion joint consists of three basic components. The tube, or lining of the joint, is made of rubber and is the only part of the joint which comes in contact with the fluid. The carcass provides the strength of the joint and consists of synthetic materials embedded with metal wires for reinforcement. The neoprene cover protects the joint from external environmental attack. The vendor recommends a service life of 12 years. However, the REJ which failed was within its service life, was hydrostatically tested, and externally inspected. The root cause of the failure determined that the rubber liner on the interior surface of the expansion joint had been worn through by flow induced erosion. The water penetrated the polyester carcass to the wire banding. The corrosion of the wire reinforcing bands degraded the integrity of the expansion joint. The breech of the REJ wall occurred when a pressure transient was induced on the river water system. This pressure transient was induced by dynamic MOVATS testing of MOV-RW-116A (auxiliary river water pump discharge) and was within the design limitations of the REJ. The inspectors considered the root cause analysis to be well developed and have a proper technical basis for its conclusions.

4.2 Post-Accident Monitoring Recorders

During component walkdowns, Engineering Department personnel identified a seismic inadequacy for the Unit 1 post-accident monitoring strip chart recorders. Recorders for containment hydrogen, refueling water storage tank level, pressurizer level, containment pressure, containment radiation, reactor coolant loop temperature, and reactor vessel level were improperly mounted for proper seismic qualification. The inspectors reviewed the licensee's basis for continued operability and noted that redundant/equivalent indicators are available to the operators for post-accident monitoring during a seismic event. The licensee plans to correct the seismic deficiency during the next refueling outage. The inspectors considered this action to be acceptable, and the identification of the seismic deficiency to be indicative of a detailed engineering walkdown.

4.3 Engineering Program Review

4.3.1 Procedures

The inspector reviewed the following Nuclear Power Division Administrative Procedures (NPDAP) and Nuclear Engineering Administrative Procedures (NEAP):

NPDAP 2.4, Engineering Memoranda, Revision 3
NPDAP 2.12, Long-Range Planning Program, Revision 1
NPDAP 2.17, Workload Priority System, Revision 1
NPDAP 7.2, Change Control, Revision 4
NPDAP 7.4, Temporary Modifications, Revision 3
NPDAP 7.7, Plant Installation Process Standards, Revision 2
NPDAP 8.16, Computer Administration and Assurance Program, Revision 0
NEAP 1.1, NED Functional organization, Revision 0
NEAP 2.13, Technical Evaluation Reports, Revision 12

Based upon the review of the procedures, the inspector concluded that adequate administrative controls exist to ensure that the engineering work is properly performed.

4.3.2 Work Backlog

The inspector reviewed the Nuclear Engineering Department (NED) performance indicators monthly report for the month of October 1995. The report was issued November 17, 1995, and shows a small downward trend in the total number of open work items for NED since May of 1995. The overall performance trend page also has a table that correlates Engineering Department priorities to workload prioritization system priority point values. The report evaluates performance by work item-type (engineering memoranda, technical evaluation reports, design-change packages, record updates, etc.) and delineated goals to be met for those items. In those cases where goals were not being met, corrective actions were specified. In several cases, the goals had been exceeded on a routine basis. In those areas, more aggressive goals were adopted.

The inspector reviewed the data for the individual work item types. The following observations were made:

<u>Engineering Memoranda (EM)</u> - the data show that nearly 62% of all the outstanding engineering memoranda are beyond their target due dates. The corrective action for the vast majority (Priority 3 and Priority 4) will be to review and renegotiate the due dates semiannually.

The inspectors reviewed the engineering memoranda backlog trends and reviewed the actual backlog to ensure that no safety-significant EMs were outstanding. From the licensee's performance indicator data (November 17, 1995), a total of 460 EMs were open, of which 284 were past their due dates. The inspectors specifically reviewed the Priority 4 EMs in detail and to ensure that low priority assigned did not result in any safety issues being buried in the backlog since these had the greatest number overdue (206). Trend information indicates that progress is being made to reduce this backlog as the number of Priority 4 EMs has been reduced from 429 in May to 327 in October, a reduction rate of 20 per month. Of the remaining Priority 4 EMs, the inspectors did not identify any open EMs that posed an immediate safety concern. However, as evidenced by the following selected EMs, there still existed a significant number of valid technical issues that remained to be addressed. This indicates to the inspectors that continued effort is needed by NED to address the backlog reduction. Even though the licensee is within their goal of less than 250 Priority 4 EMs overdue, it was apparent to the inspectors that additional attention is needed in ensuring the timely resolution of these EMs, since 62% of all Priority 4 EMs are currently overdue.

EM 104091 was prepared on October 22, 1992, to evaluate replacement parts for the emergency diesel generator, but has not yet been completed. The old parts are no longer available from the vendor, and substitute parts have been recommended. An evaluation of replacement relays is still in progress. A replacement generator bearing has not yet been evaluated. Per the licensee's prioritization system, all spare part evaluations, regardless of their role with respect to equipment safety significance, are assigned Priority 4.

EM 108897 was prepared December 9, 1994, to evaluate necessary corrective actions to prevent future failures of an auxiliary feedwater pressure switch. This pressure switch functions to isolate steam generator blowdown upon auxiliary feedwater pump start in order to conserve steam generator water inventory. Moisture intrusion has caused previous failures of this pressure switch. There is no immediate safety issue in this matter since these switches are currently operable, are not safety related, and no credit is taken for blowdown isolation in the accident analysis section of the final safety analysis report. This EM was designated as Priority 4 and is past the original due date of June 1, 1995.

EM 109613 was prepared on February 25, 1995, to evaluate the lowering of the Unit 2 emergency switchgear high temperature alarm (Annunciator A-10, F6). The current setpoint appears to be above the maximum allowed setpoint based on a draft calculation. Loss of switchgear ventilation is a major contributor to core damage frequency per the licensee's individual plant examination. This EM was designated as Priority 4 and is past its original target due date of March 30, 1995. The current engineering memorandum prioritization system specifies that Priority 3 should be assigned to evaluations that affect the operability of PRA-sensitive equipment. This item has now been assigned Priority 3 and is being actively worked by the licensee.

EM 109376 was prepared on January 31, 1995, to evaluate the constants used in the reactor coolant system (RCS) leak rate calculation. This evaluation is to further refine the accuracy of the leak rate calculation, since it is possible to calculate a negative value for unidentified leakage. This EM was designated Priority 4 and has not yet been worked by engineering, even though its requested due date was March 30, 1995.

The inspectors also discussed with the Manager of Quality Services a finding identified in a recently-completed quality assurance (QA) audit. The EM backlog was also reviewed by this organization. The licensee's oversight group reached conclusions similar to those above. The inspectors found this audit to reach credible conclusions with supportive examples. In general, the QA audit found examples of EMs in which:

Originators of EMs were not always notified of target date extensions;

The prioritization of EMs was not consistent with current prioritization system. Several operator workarounds were identified as Priority 4 when Priority 2 would have been more appropriate.

A lack of timely resolution of EMs existed; and

Safety significance of components is not considered for EMs involving spare part evaluations.

Design-Change Package (DCP) Records Updates - the goal for records updates is that no more than 24% of all outstanding record updates would be greater than two years old. The performance indicators report shows that over 50% are greater than two years old. Corrective actions listed are to emphasize completing records updates for DCPs that were operationally accepted more than three years ago (this is in response to a quality assurance audit finding).

Based on the information in the October performance indicators report, it is apparent that timeliness continues to be a problem. Duquesne Light Company has identified this problem via internal audits, and actions are being implemented to address the issue.

4.3.3 Workload Prioritization

The inspector selected a number of items for review that were shown in the site work prioritization system database as being open. The work priorities are labeled 1 through 4, with 1 being the highest. The items selected were shown as Priority 1 or 2, with the exception of the technical evaluation reports, all of which were shown as Priority 4. In addition, one Priority 4 EM was selected for review, as a result of being referenced in a technical evaluation report (TER). Also, the listing of Priority 4 EMs was reviewed to determine if any safety-significant work was being overlooked due to having been assigned a low priority. During discussions with engineering and plant personnel, the inspector determined that critical work, involving immediate operational needs, was normally dealt with and completed prior to the assignment of priorities. The inspector noted that provisions exist for increasing the priority of a specific work item through management input and identified an instance where this had occurred.

Of the six Priority 2 EMs selected for review, four were past their target due dates and remained unanswered at the time of the inspection. One of the six had been answered within a week of its origination.

Several of the selected items (five TERs and one engineering memorandum) shown as open in the workload prioritization system database were found to be completed and issued. While reviewing the identified discrepancies in the data, Duquesne Light Company personnel determined that this was due, in part, to items being closed out in the document control system without the duplicate entries necessary to close the item in the workload prioritization system having been made. At the end of the inspection, Duquesne Light Company was in the process of reviewing and verifying the status of the items in the workload prioritization system database. Updates, as necessary, were to be made during the process.

The workload prioritization system does not currently fall under the software quality assurance system specified in NPDAP 8.16. The program applies to new software being procured and to revisions of existing software, when they are performed. The procedure does not require backfitting to existing software at this time.

4.3.4 Conclusions

While progress is being made, the engineering work backlog continues to be large in comparison to the rate of work accomplishment. No issues that would pose an immediate safety concern were identified in the engineering backlog nor were any safety issues being overlooked. However, the timeliness of record updates, engineering response to issues, and the prioritization of issues affecting safety-related equipment, such as the evaluation of lowering the Unit 2 emergency switchgear high temperature alarm, appear to be in need of improvement. Similar conclusions were reached by the licensee's quality assurance organization in an audit of EMs. The computer-based workload prioritization system is a good initiative to assign site-wide priorities to all outstanding work and is based upon the affect of the work on plant operation. While it may not always initially reflect the needs of operations and maintenance, mechanisms exist for adjusting priorities, and these are being used.

4.4 Electrical Systems Open Item Review

4.4.1 Settings of Degraded Grid Relays (Unresolved Item 50-334/91-80-04; 50-412/91-80-04)

Issue

The NRC Electrical Distribution System Functional Inspection (EDSFI) team identified that the setpoint of the degraded grid relays were set at 90% $\pm$ 1.6% of their respective nominal bus voltage. The team noted that the 4160V and 480V motors had a continuous rating of 90% of the nominal nameplate voltage, *i.e.*, 3744V and 414V (460V x 0.9), respectively. This would result in the 4160V motors operating at a voltage less than 90% of the nameplate under degraded grid conditions and the 480V motors would be within 10V of their continuous rating. The operating voltages would be reduced further when cable voltage drops are considered.

This item was unresolved pending the performance of an appropriate licensee analysis to justify the degraded grid relay setpoints.

Licensee Actions

Subsequent to the EDSFI inspection, the licensee adjusted the setpoint of the degraded grid relay setpoints to address questions regarding the adequacy of the voltages to safety-related loads. Issues were identified regarding the available starting voltages and ampacity of some cables during their evaluation of the Unit 1 setpoints. These issues were documented in Problem Report 1-93-45, and any conditions determined to potentially affect the ability of safety equipment to perform their function were addressed prior to plant restart from the refueling outage.

As discussed in a letter from the licensee to the NRC, dated March 23, 1994, the 120 Vac calculations needed to be completed at both units prior to determining whether the new relay setpoints would remain as the final setpoints. The schedule for completion of the calculations was May 1996 for Unit 1 and June 1995 for Unit 2.

The licensee completed Calculation 10080-E-76, "Voltage Levels at 120 Vac Loads," for Unit 2. This calculation determined the voltage available at the 120 Vac loads under several operating conditions, including minimum voltages during degraded grid conditions and maximum voltage conditions during plant shutdowns. The available voltages were evaluated to ensure that the voltages were within the minimum and maximums identified by the component manufacturer, or that they were within $\pm$ 10% of nominal voltage if the vendor did not specify minimum or maximum voltages. This evaluation determined that adequate voltage was available to all loads during minimum voltage conditions. The evaluation also determined that, during plant shutdown conditions and the electrical buses being backfed through the main transformer, voltages to many of the components could be slightly higher than the acceptable values specified. Most of the voltages would be less than two volts above the established criteria, and the maximum component could be at 6.44 volts above the acceptance criteria specified in the calculation. As a result, engineering has recommended transformer tap changes to reduce the voltages and thereby minimize the number of components that could be outside of the recommended values established in the calculation. Maintenance work requests have been written to implement the tap changes.

The licensee then re-performed the calculation using the revised transformer tap connections and found that most of the cases where the maximum voltage could be exceeded during plant shutdowns would be eliminated by the tap changes. The voltages with the revised tap settings could be slightly higher than the acceptance criteria for one circuit; and, under degraded grid conditions, two circuits could be slightly lower than the voltages desired in the calculation. The conditions were appropriately evaluated and resolved by an engineering analysis and/or component testing.

NRC Review and Conclusions

During NRC Inspections 50-334/94-10 and 50-412/94-10, the inspector reviewed the relay settings and their bases. The inspector concluded that the degraded grid relays had been conservatively set and that there was an adequate basis for the specified settings. The issues remained open at that time pending the completion of the 120 Vac voltage drop calculations and the resolution of any resulting issues.

During this inspection, the inspector reviewed the Unit 2 120 Vac system voltage drop calculation assumptions, conclusions, and recommendations. The inspector found that the calculation was thorough and used conservative assumptions to ensure that the results reflected worst-case conditions. Operating conditions, which were representative of worst-case conditions for low voltage and high voltages, were evaluated, and potential concerns were documented in the calculation and in a plant problem report. Equipment operability assessments were performed, and appropriate recommendations were made to optimize system performance.

This item is closed for Unit 2. The Unit 1 120 Vac system voltage drop calculations were in progress at the time of this inspection. This item will remain open for Unit 1 pending licensee completion and NRC review of the calculation.

4.4.2 Emergency Diesel Generator Mode Change (Unresolved Item 50-412/91-80-09)

Issue

The EDSFI team identified that, when a Unit 1 EDG is in parallel with the off-site power, a degraded grid condition or loss of off-site power would cause a trip of the normal breaker and the immediate addition of emergency loads. The addition of the emergency loads could be added before the governor could change from droop to isochronous operation and before the voltage regulator could change from the parallel to isolated mode, and potentially result in the failure of the EDGs to properly start and power emergency loads. This is a result of a set of contacts associated with the tripped breaker, along with contacts associated with the closed EDG breaker, signaling the load sequencer to load the emergency bus.

This item had been previously addressed for Unit 1 and was unresolved for Unit 2 pending the performance of licensee reviews and/or analysis.

Licensee Actions

The licensee performed Calculation 10080-E-243, "EDG Mode Change Due to LOOP During OST 2.36.1," to analyze this situation. The results of this analysis showed that if the normal power feed was lost to the 4160 volt bus while the EDG was operating in the test mode the following would occur:

- The actuation of a directional overcurrent relay would cause the tie breaker between the normal and emergency 4160 volt buses to open when the EDG begins to supply the loads on the normal bus. The opening of the tie breaker would trip all of the motor loads on the emergency bus and start the EDG load sequencer.
- The EDG frequency would drop to approximately 58 Hz when the feeder breaker trips and then overshoot to approximately 63 Hz as a result of the load rejection when the feeder breaker opens on overcurrent. This transient would not result in an overspeed trip of the EDG.
- The loads would be sequenced onto the emergency bus starting 0.5 seconds after the feeder breaker trip. The analysis showed that the emergency bus voltage and frequency would stabilize before the next load was sequenced onto the bus and that all motors could be started and accelerated during the transient.

The overall conclusion of the analysis was that the mode change would be accomplished without any detrimental effects on the EDG or the supplied loads.

NRC Review and Conclusions

This issue was previously updated in NRC Inspection Report Nos. 50-334/93-23 and 50-412/93-27. At that time, the licensee had completed their analysis for this issue on Unit 1. The item remained open pending NRC review of the licensee's assumptions and completed analyses of both units for evaluation of the EDG and motors' operation during load sequencing and a degraded grid or loss of off-site power event.

The NRC completed their review of this issue for Unit 1, as documented in Inspection Report Nos. 50-334/94-10 and 50-412/94-10. However, the analysis for Unit 2 was not available for review at that time.

The inspector reviewed the design inputs, assumptions, approach, and results of the calculation and discussed the analysis with the responsible engineer. Based on these reviews and discussions, the inspector concluded that the licensee had adequately evaluated this concern and that no additional actions are required. This item is closed.

4.4.3 Penetration Heat Loading (Unresolved Item 50-334/91-80-10)

Issue

The EDSFI team reviewed Calculation No. 10080-E-84, Revision 3, to assess the suitability of the Unit 2 electrical containment penetrations to carry continuous currents without exceeding the allowable temperature rating of the penetration. The team compared the requirements of the calculation against the design limits of IEEE Standard 317-1976, which is referenced in the final safety analysis report (FSAR). The team noted that the calculation had used a conservative assumption that the maximum continuous currents were equal to the overload settings of the protective devices rather than the load demands. Also, the calculation assumed a 100% load factor and an ambient temperature of 40°C for each penetration and recommendations of IEEE 317 that the maximum heat loading should be less than 30 watts per foot were also considered in the calculation.

For Unit 1, no calculation was available for review; and, although Specification No. BVS-384, Revision 3, referenced IEEE 317, the team had no basis for concluding that the Unit 1 penetrations were adequately sized and protected for continuous loads.

The team also noted that, for Unit 1, although the design appeared to be satisfactory, the licensee did not have a basis for their determination that the capability of the penetrations to carry overload currents without exceeding the limits on temperature and mechanical loading.

The team was also unable to conclusively determine whether the protective devices for the Unit 1 circuits were appropriately chosen to ensure that the penetration conductors were properly protected against prolonged overcurrents.

This item was unresolved pending the performance of appropriate calculations by the licensee.

Licensee Actions

The licensee performed an evaluation of these issues and documented the results in Calculation 8700-E-251, "Evaluation Of Electrical Penetration Integrity For Steady State & Short Circuit Conditions," and Addenda 1A, 2A, and 3A to the calculation. For the 480 volt and 4160 volt penetrations, these calculations compared the circuit loads to the design ampacity of the penetrations based on the design specification and vendor drawings. The total heat load generated during various plant operating modes was also calculated to ensure that the watts per foot heat load were less than that established to be acceptable during prototype testing. The short circuit capability was also evaluated by assessing the available short circuit at the penetration against prototype testing, or by verifying that the I^2t rating of the conductor would not be exceeded before the fault was interrupted by the circuit breaker.

The results of this analysis showed that the steady state heat loading of the penetration was well within the acceptance criteria of 30 watts per foot with the smallest margin being approximately 33%. The short circuit capabilities were also found to be acceptable and again had significant margin between the available short circuit currents and the conductor design capability and prototype test results.

For the electrical penetrations designed for control circuits, the licensee compared the load currents for each conductor to the design rating of the penetration conductors to ensure that the individual currents were within the design and that the penetration heat load would not be excessive. The design limit was 11 amps, and the maximum continuous load on any conductor was determined to be 5 amps. The effects of fault currents on the penetration were also reviewed to ensure that there was adequate overcurrent protection provided for the circuits to protect the penetration conductors or, in the cases where overload protection was not provided, that the fault currents were below a level that could result in damage to the conductors or penetration. Most of the cases, where overcurrent protection was not available, were with the secondary side of motor control center control power transformers. The plant design does not utilize fuses on either the primary or secondary circuit of the control power transformers. The licensee calculated that the maximum short circuit at the secondary of the 150 VA control transformer would be approximately 31 amps. The available short circuit calculation was conservative, since the impedance of the cables between the transformer and the penetration was not included. The penetration conductors are #12 AWG 90°C-rated conductors with a continuous current carrying rating of 30 amps. The licensee concluded that there would not be any detrimental effects on the penetration, since the available short circuit calculation was conservative and the control power transformers could not sustain a current at this level for any significant period without failure. This was confirmed by tests performed by the vendor that verified that shorted transformers would fail open in a very short time. Also, the licensee had previously replaced the original control transformers with an encapsulated type to ensure that failures of the transformers would not create a fire hazard.

The licensee also evaluated the instrumentation penetrations to ensure that normal full load currents were within the penetration design ratings and that there were no overloads of fault current conditions that would challenge the integrity of the penetrations. No problems were identified by the licensee.

NRC Review and Conclusions

This item was reviewed during NRC Inspections 50-334/94-10 and 50-412/94-10. However, the licensee analysis had not progressed to a point to permit the inspector to review this issue.

The inspector reviewed the design inputs, assumptions, methodology, and results of the calculations and discussed the calculations with the engineering staff. The inspector found that the calculations were thorough and utilized design inputs that yielded conservative results. The inspector concluded that the licensee evaluation provided an appropriate design basis for the adequacy of the electrical penetrations. This item is closed.

4.4.4 Availability of Design Documents (Unresolved Item 50-334/91-80-12)

Issue

The EDSFI team identified areas where an adequate evaluation of the Unit 1 electrical system could not be performed because of a lack of documents. These areas included: (1) sizing of MCC cables for power and control circuits, (2) acceptability of the bus fast transfer scheme, (3) short circuit current available at the 120 Vac buses, and (4) coordination of DC protective devices.

These issues were unresolved pending NRC review of appropriate documentation when made available by the licensee.

Licensee Actions

1. Sizing of MCC cables - The licensee previously completed calculations to assess the adequacy of the MCC power cables. At the time of the previous NRC review, the inspector concluded that all power cable issues had been resolved except for the adequacy of several cables located in duct banks. The adequacy of these cables was reassessed by the licensee in Addenda A2 to Calculation 8700-E-221, "4160 and 480 Volt AC Load Management and Voltage Profile Calculations." The result of this analysis was that the cable sizing was adequate and that the cables would operate below their design-temperature limit.

   The licensee also performed Calculation 8700-E-113 to evaluate the adequacy of the control circuit design for the Unit 1 safety-related motor control centers. The licensee had not completed the software quality assurance review of the computer program utilized in the calculations; and, therefore, the calculation was not issued at the time of the inspection. However, the evaluation of all circuits and components was complete, and the responsible engineer did not expect any changes when the calculation was finalized. The potential problems that were identified were documented in Problem Report 95-495. The potential problems that affected safety-related components were that, in two cases, the inrush rating of the control power transformers exceed the manufacturer's specification. However, the voltage provided to the motor starters was above the minimum required to operate the starter; and, once the contactor closes the control power, transformer steady state load is within the continuous rating of the transformer. Engineering also reviewed the maintenance history of these components for the period between 1989 and 1995 and did not identify any problems. Engineering recommended replacement of the existing 150 VA transformers with 250 VA transformers. The other potential concern, which was identified during the calculation, was the potential for some circuit relays being subjected to slightly higher voltages than those specified by the manufacturer. The higher voltage conditions would be present only during plant outage conditions when the electrical buses are lightly loaded. Engineering reviewed the maintenance history for the affected components and did not identify any problems that may have been the result of high voltage conditions. Engineering recommended that the affected relays be replaced with similar relays with coils rated at 127 volts.

2. Bus Fast Transfer Evaluation - The licensee performed Calculation 8700-E-271, "Beaver Valley Power Station - Unit 1 Station Service System Dynamic Stability Study," to evaluate the adequacy of the electrical system under various transient conditions. This study included an assessment of the response of the electrical system and components during a fast transfer of the 4160 volt bus supply from the normal to alternate feed. For the transients involving fast bus transfers, the analyses were performed with an assumed dead bus time of six cycles and then was repeated assuming an eight-cycle bus dead time. These times were chosen because past data indicated that, at one time, a bus dead time of 7½ cycles was experienced, and six cycles is the expected dead bus time based on design-breaker operating times. Recent testing indicated that the bus dead time decreased from 7½ cycles to around 5½ cycles following circuit breaker maintenance.

   The analysis determined the minimum bus voltages and frequencies expected to occur during the transients and compared them to the protective relay setpoints to determine if relay actuations would occur. The difference in the residual bus voltage and the incoming bus voltage was also determined to ensure that the difference would not be significant enough to result in any equipment damage during the transfer. The resultant voltage in per unit volts per hertz was compared against the recommended maximum of 1.33 volts/hz, as specified in ANSI C50.41-1982, "Polyphase Induction Motors for Power Generating Stations."

   The results of the analysis indicated that there were some cases where bus transfers could be unsuccessful in that bus voltage and frequency dips could result in the actuation of protective relays. These relay actuations could result in the tripping of bus feeder breakers and pump breaker trips. However, in all cases, the emergency bus would be re-energized by the emergency diesel generator, and all of the scenarios were bounded by the UFSAR analyses. The licensee also determined that, in some cases, the resultant voltage differential exceeded the 1.33 volts/hz by a small amount.

Based on the initial calculation results, the licensee reviewed the protective relaying setpoints and has generated setpoint changes that should eliminate the potential for protective relay actuation for most of cases analyzed. In the cases where there is a potential for relay actuation, the emergency buses can be safely re-energized from the emergency diesel generators. The cases where the volts/hz limit may be exceeded amount were determined not to be a safety concern, since the expected value is just slightly above the recommended limit, there have been no identified failures in the industry due to excessive volts/hz during fast transfers, the expected failures would be a result of the cumulative effects of numerous fast transfers, and the number of actual fast transfers is small.

The licensee is planning to replace the main transformer during the next refueling outage and plans to repeat the analyses using the design parameters for the new transformer and to implement the relay setpoint changes during the refueling outage. The licensee is also considering testing changes to permit the monitoring of bus voltage during transfers to obtain a measure bus dead time directly, which would eliminate the need to rely on computer sequence of event data and design-breaker operating times.

3. 120 Vac Short Circuit Analysis - The licensee performed Calculation 8700-E-120, "208/120V Three Phase and 120/240V Single Phase Class 1E Distribution Panels Short Circuit Analysis," to calculate the available short circuit current at the panels and to verify the adequacy of the short circuit ratings of the panels and their associated circuit breakers. The results of this calculation showed that the available short circuit currents were less than the panel and circuit breaker ratings and that there was coordination between the panel circuit breakers and the upstream panel feeder circuit breaker.

4. Coordination of DC protective devices - The licensee performed Calculation 8700-E-207, "Short Circuit Analysis 125V Class 1-E DC System," to assess the system protective device coordination. Several potential coordination concerns were identified during this calculation and were identified in a problem report. The conditions were corrected by minor modifications to the circuits.

<u>NRC Review and Conclusions</u>

1. Sizing of MCC cables - The inspector reviewed the assumptions, results, and recommendations associated with the calculations. The assumptions utilized were found to be appropriate and chosen as to ensure conservative results. The results were clearly specified, and conditions, where the acceptance criteria within the calculation were not met, were documented and evaluated in a plant problem report. The

potential effects on equipment operability were assessed and documented in the problem report. The recommendations were also appropriate and resulted in all conditions being appropriately resolved.

2. Bus Fast Transfer Evaluation - The inspector reviewed the results of the licensee analyses and discussed the issues with the responsible engineers. The inspector found that the licensee had appropriately addressed this issue and planned to repeat the analyses, following the replacement of the main transformer during the next refueling outage. The inspector also reviewed the potential implications of the cases where the analyses indicated that a fast transfer may be unsuccessful. The inspector noted that most of the potential failures involved the loss of nonsafety loads due to protective relay actuation and the potential failures were more likely when an eight-cycle bus dead time was assumed. The expected bus dead time would be approximately five to six cycles. In the cases where power to the safety buses could be lost during a transfer, the emergency diesel generators would then start and power the bus. Also, the planned relay setpoint changes will further minimize the potential for any failures during fast transfers. The inspector also found that the licensee had appropriately evaluated the cases where the voltage mismatch exceeded the recommended value of 1.33 volts/hz.

3. 120 Vac Short Circuit Analysis - The inspector reviewed the calculation assumptions, results, and an alternate calculation that was performed to verify the results of the calculations performed with by a computer. The inspector found that the assumptions that were utilized in the calculation yield conservative results the calculation was properly performed. The results were properly evaluated and documented.

4. Coordination of DC protective devices - This item was previously reviewed during NRC Inspection 50-334/94-25 and 50-412/94-26 and was found to have been appropriately resolved with the exception of completing the minor modifications. During this inspection, the inspector noted that the modifications had been completed.

   This item is closed.

4.4.5 Emergency Diesel Generator Frequency Response (Unresolved Item 50-412/94-10-01)

Issue

During a review of performance curves for the Unit 2 EDGs, an NRC inspector noted that the frequency of Emergency Diesel Generator 2EDG1 had a long recovery time. The frequency reached a maximum of 64.5 Hz during testing and did not drop to the nominal value of 60 Hz for approximately 16 seconds. At the time of that inspection, the licensee had not completed an engineering evaluation of the test data and a resolution had not been reached by the end of the inspection. Following the inspection, the licensee informed the inspector that the slow response was probably the result of misadjustments of either a governor needle valve or the control box.

This item was unresolved pending evaluation and resolution by the licensee and subsequent NRC review.

Licensee Actions

The licensee monitored the performance of the EDG during the monthly surveillance tests and observed a similar frequency response during each of the tests. The governor was then replaced during the refueling outage in accordance with the preventive maintenance program. The governor for each of the EDGs is replaced on a five-year frequency. Tuning was then performed on the replacement unit, and the desired frequency response was achieved. The Maintenance Department was in the process of revising the maintenance procedures to add a step to routinely obtain transient analysis data following work on the EDG governor.

NRC Review and Conclusions

The inspector discussed the problem with the responsible design engineer and system engineer and reviewed the results of the testing performed after the governor replacement. The inspector found that the slow frequency response of the EDG was eliminated by the maintenance and that the licensee actions to improve the post-maintenance testing were appropriate. This item is closed.

4.4.6 Harmonic Distortion Effects on Degraded Grid Relays (Unresolved Item 95-09-05)

Issue

The Unit 1 emergency bus degraded grid relays were upgraded from Asea Brown Boveri (ABB) Model ITE 27H to ABB Model ITE 27N to increase setpoint accuracy and gain added control over the reset point. The inspectors noted that the ABB data sheets indicated the relays were susceptible to setpoint inaccuracy in the presence of harmonic distortion. ABB provides a harmonic filter to counter this problem. However, the licensee did not install the filter, or evaluate harmonic distortion levels on the emergency buses. The issue of bus harmonic distortion was unresolved pending NRC review of the licensee's evaluations.

Licensee Actions

The licensee evaluated the test equipment utilized to perform the relay calibrations to ensure that there was no excessive harmonic distortion in the test signal. The licensee evaluation concluded that the test equipment used at Beaver Valley had less than the maximum of 0.3 % harmonic distortion that was specified by the relay manufacturer.

The licensee also monitored the 480 volt and 4160 volt safety buses to assess the extent of any harmonic distortion on the busses. The analyzer utilized during the monitoring measured up to the 50th harmonic. The results of the bus monitoring showed that there was no significant harmonic distortion present. The licensee plans to have a calibration check performed on the analyzer to ensure the results were accurate and then factor the monitoring results into the relay setpoint calculations. Based on the very low level of harmonic distortion measured, the licensee did not expect any effect on the relay setpoints.

NRC Review and Conclusions

The inspector reviewed the results of the licensee evaluations and bus monitoring data and discussed the issue with the responsible engineer. The inspector concluded that the licensee was properly addressing the issue and that there was no concern with harmonic effects on the degraded grid relays. This item is closed.

4.4.7 Overall Summary

The inspector found that the calculations were well organized and contained good detailed assumptions, results and recommended actions. Deficiencies were documented in problem reports and included a thorough evaluation on the effects of the component and or system operability. The calculations are contained in a computer data base to facilitate the performance of plant design changes or additional analyses.

5.0 PLANT SUPPORT (71750, 92709, 92711)

5.1 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. Licensee personnel were observed to be properly implementing the radiological protection program.

5.1.1 Cooling Tower Blowdown Flow Instrumentation

The inspectors performed a review of radioactive liquid waste discharge authorization permit RWDA-L-04215, to ensure the discharge was in accordance with the offsite dose calculation manual (ODCM). This discharge involved the release of 28,000 gallon from liquid waste tank LW-TK-7A. Per the discharge permit, a minimum cooling tower blowdown flow of 10,000 gpm must be satisfied for proper dilution of the liquid waste prior to release to the environment. This dilution factor is used in the calculation of annual doses to man from routine batch releases of reactor effluents. These calculations are used to assure compliance with 10 CFR 50, Appendix I, which provides guidance on the doses to members of the public resulting from effluent releases that may be considered as low as reasonable achievable. The limit for the annual dose to the total body is 3 mrem or 10 mrem to any organ of an individual in an unrestricted area due to liquid effluent releases per reactor unit.

During the inspectors walkdown of the operating procedure for liquid waste discharges, the inspectors noted a discrepancy involving cooling tower blowdown flow. Specifically, the combined cooling tower blowdown flow recorder (FR-CW-101-1) for both units indicated a value of 25,350 gpm. However, the individual flow recorder for Unit 1 (1FR-CW-101) indicated a blowdown flow of 7,500 gpm, while the individual flow recorder for Unit 2 (2FR-CW-101) indicated a blowdown flow of 7,200 gpm. This is a resultant 10,000 gpm less than the combined flow recorder. All recorders were within their respective calibration periodicity. During verification of minimum flow for the discharge permit, operators typically used the combined flow instrument since a low flow alarm is part of its design. However, the inspector was initially concerned that if the 25,000 gpm value was in error and that 15,000 gpm was accurate, then the dilution factor used would be higher by almost a factor of two and result in a nonconservative calculation for offsite dose. The inspectors raised this question to the effluents division who were unaware of this flow discrepancy. A subsequent mass balance calculation verified that the 25,000 gpm value was accurate and that the Unit 1 individual flow recorder was suspected of being in error. Thus, the inspectors' safety concern was adequately addressed. Effluents personnel plan on re-reviewing previous discharge permits to identify if the individual flow recorders were used so that the offsite calculated doses can be re-adjusted to a more accurate value as part of the licensee's submittal of the annual effluents report. Instrumentation and controls personnel are also currently investigating the cause of this anomaly.

The inspectors also discussed with the Manager of Quality Services as to why this flow discrepancy was not earlier identified via an annual audit of the effluents program. The inspector recognizes that this difference in flow is not easily identifiable, since a multiplication factor of 650 must be applied to the combined recorder to yield the flow rate. Additionally, these recorders are located in different areas of the plant. However, the inspector concluded that an opportunity existed for Quality Assurance identification of this flow discrepancy as part of the effluents audit.

5.1.2 Health Physics Actions in Response to River Water Expansion Joint Rupture

The inspectors reviewed the initial and follow-up actions by health physics personnel in response to the river water leak in the primary auxiliary building (PAB). This building is part of the radiologically controlled area (RCA). Due to the overflow of various contaminated sumps in the PAB, the principle concern of a potential release of radioactive material was immediately addressed. All outside areas adjacent to the RCA were inspected. Dampness was identified outside of the fuel handling building. Water may have flowed from the 735-foot elevation of the PAB and into the 735-foot elevation of the fuel handling building and beneath a door. The dampness was cleaned up and the absorbent material was analyzed; no isotopes were identified. There were no other locations identified in which water may have escaped to the environment. This was also later confirmed via the radiation release monitoring system.

The primary elevations of the PAB which were affected by the spill were the 735 and 722-foot levels. As the extent of any contamination was initially unknown, precaution contamination control measures were put in effect. This included restricting access and requiring personnel to wear partial anticontamination clothing. Subsequent surveys were reviewed by the inspectors and indicated that the principle areas which became highly contaminated included the liquid waste tank (LW-TK-2A, 2B, 3A, 3B) cubicles (30,000 dpm/swipe), the east valve trench (500,000 dpm/swipe), and primary drain transfer tank Number 2 (40,000 dpm/swipe). The inspectors walked down these areas and verified posting were consistent with the survey results. Long-term actions to decontaminate these areas are in progress.

Approximately 71,000 gallons of river water were transferred to the liquid waste system. An initial sample of liquid waste tank '7B' on December 18 indicated cobalt-60 at 3.347 E-7 μCi/ml and cesium-137 at 4.095 μCi/ml. Liquid waste tank '7A' had similar results. A discharge of these tanks was permissible and would have resulted in an organ dose of 0.68 mrem and a total body dose of 0.50 mrem to the maximum exposed individual. This was within the annual 10 CFR 50, Appendix I, limits of 10 mrem organ dose and 3 mrem total body dose. The licensee, however, appropriately elected to process this liquid waste to further reduce the resulting contribution to the annual offsite dose. Multiple efforts to process the liquid waste were successful and resulted in a reduction in dose to .015 mrem organ dose and .01 mrem total body dose. The inspectors considered these efforts to be properly consistent with the ALARA policy of effluent releases as discussed in Appendix I.

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.

5.2.1 Security Force Union Contract Expiration

5.2.1.1 Security Force Lockout

The contract between the union security force (SF) and its contractor management expired on November 30, 1995. Collective bargaining took place prior to contract expiration and continued after the contract expired, but failed to ratify a new contract by December 1, 1995. The contractor then gave the union an ultimatum to ratify the contract within 72 hours or face a lockout. The ultimatum did not result in ratification of a new contract. The contractor initiated a lockout of the SF bargaining unit members at 1 p.m. on December 4, 1995, and, shortly thereafter, the licensee escorted all SF bargaining unit members from the station.

Prior to the expiration of the contract, the contractor had brought in and trained a contingency force, consisting of a number of the contractor's supervisory personnel from other nuclear facilities, to augment non-bargaining members in the event of labor actions. The NRC verified that the contingency force was at the station and in position when the lockout occurred. The NRC observed the lockout activities and determined that it did not adversely impact or decrease the effectiveness of station security. In addition, the inspectors noted that the licensee reviewed the security work request backlog before the lockout and verified that none of them would necessitate compensatory posts or additional staffing during a lockout.

5.2.1.2 Post-Lockout Activities

A regional safeguards inspector was dispatched to the station and reviewed relative security force activities from December 5-7, 1995. The inspector reviewed a sample of contingency force training records. The records reviewed indicated that all required training/certification had been conducted and documented in accordance with the NRC-approved Guard Training & Qualification Plan. The inspector also observed and interviewed contingency force members as they performed their assigned duties. No discrepancy was identified.

The inspector discussed the impasse in negotiations with the licensee and the contractor. Based on those discussions, the inspector determined that a federal mediator had been requested and was subsequently assigned to participate in future negotiations. In the meantime, the contractor has begun the processes of hiring and training replacement members for the security force.

5.2.1.3 Contingency Planning

The inspector reviewed the contractor's contingency plans for handling a work stoppage at the station. The plans were logistically sound and had been effectively implemented at the station. The inspector also reviewed the licensee's "Nuclear Power Division Work Stoppage Contingency Plan." Based on that review and discussions with security management, the inspector determined that the plan was comprehensive, logistically sound, and had provisions to ensure: (1) unimpeded access of authorized personnel to the station; (2) unencumbered delivery of support goods to the station and unencumbered off-site shipment of radioactive materials; (3) mitigation of possible threats to the station, including abusive or violent strikers; (4) unimpeded access of medical care and ambulance services to injured or contaminated persons; and (5) unimpeded access of the local fire department to supplement the station fire fighting unit.

5.2.1.4 Conclusion

The inspector found that contingency force and non-bargaining members of the station's security force were carrying out their duties and responsibilities in a manner that would protect the safety of the station in accordance with the licensee's NRC approved security plan.

5.3 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

The inspectors reviewed the Quality Assurance assessment of the security contingency plan. The security plan was implemented as a result of the Burns International Security Services labor dispute and lockout of the guard workers. Key items evaluated included the ability to meet the Physical Security Plan, staffing levels, training and qualifications, and measures to detect and mitigate any possible threat to the site, including unimpeded plant access for plant personnel, as a result of the labor dispute. Overall, no deficiencies were identified by the Quality Assurance personnel. A valid recommendation was, however, made to increase the number of qualified response team members (RTMs) to ensure additional personnel are available in the event that existing RTMs cannot perform their job duties. This recommendation was adopted by the site security organization. Overall, the inspectors found this assessment to be well focused and thorough.

7.0 ADMINISTRATIVE

7.1 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. Preliminary inspection finding exits were held on December 7 by R. Albert in the area of security, and on December 8 by R. Fuhrmeister and L. Scholl in the area of engineering. Following conclusion of the report period, the resident inspector staff conducted an exit meeting on January 18, 1996, with Beaver Valley management summarizing inspection activity and findings for this period.

7.2 Management Meetings

Mr. Thomas T. Martin, Regional Administrator, NRC Region I, visited the site on November 29, 1995. Mr. Martin met with Mr. Thomas Noonan, Vice President of Nuclear Operations and Plant Manager; Mr. George Thomas, Vice President of Nuclear Services; and Mr. Brian Tuite, General Manager of Operations to discuss licensee performance and improvement initiatives. The Regional Administrator also toured the site with the inspector.

On December 21, 1995, the Beaver Valley Station Senior Vice President and Chief Nuclear Officer, James E. Cross, visited the Regional Administrator, Thomas T. Martin to discuss various topics of current interest to Duquesne Light Company and the NRC. Also in attendance were Roy K. Brosi, Beaver Valley Nuclear Safety Manager; Richard W. Cooper, Region I Director of Reactor Projects; and Peter W. Eselgroth, Region I Chief of Reactor Projects Branch No. 7. The topics of discussion included the following: Unit 1 forced outage rate performance improvement in the past year; the recent Unit 1 rubber expansion joint failure in the river water system and the licensee's conservative safety action to take the unit off line for repairs; progress on addressing biological attacks on river water systems; maintaining adequate staffing of on-shift senior reactor operator licensed personnel; steam generator water chemistry; the station's component position verification program and station tracking and trending of personnel errors. The visit lasted about an hour and a half.

7.3 NRC Staff Activities

Inspections were conducted on both normal and backshift hours: 17.5 hours of direct inspection were conducted on backshift; 30 hours were conducted on deep backshift. The times of backshift hours were adjusted weekly to assure randomness.